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and

THE WORLD BANK ESMAP

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAM

Proceedings of the Regional Seminar on Electric Power System Loss Reduction in the Caribbean

Kingston, Jamaica

July 3-7, 1989

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAM

PURPOSE

The World Bank/UNDP/Bilateral Aid Energy Sector Management Assistance Program (ESMAP) was launched in 1983 to complement the Energy Assessment Program which had been established three years earlier. The Assessment Program was designed to identify the most serious energy problems facing some 70 developing countries and to propose remedial action. ESMAP was conceived, in part, as a preinvestment facility to help implement recommendations made during the course of assessment. Today ESMAP is carrying out preinvestment and prefeasibility activities in about 60 countries and is providing a wide range of institutional and policy advice. The program plays a significant role in the overall international effort to provide technical assistance to the energy sector of developing countries. It attempts to strengthen the impact of bilateral and multilateral resources and private sector investment The findings and recommendations emerging from ESMAP country activities provide governments, donors, and potential investors with the information needed to identify economically and environmentally sound energy projects and to accelerate their preparation and implementation. ESMAP's policy and research work analyzing cross-country trends and issues in specific energy subsectors make an important contribution in highlighting critical problems and suggesting solutions.

ESMAP's operational activities are managed by three units within the Energy Strategy Management and Assessment Division of the Industry and Energy Department at the World Bank.

- ***The Energy Efficiency and Strategy Unit*** engages in energy assessments addressing institutional, financial, and policy issues, design of sector strategies, the strengthening of energy sector enterprises and sector management, the defining of investment programs, efficiency improvements in energy supply, and energy use, training and research.
- ***The Household and Renewable Energy Unit*** addresses technical, economic, financial, institutional and policy issues in the areas of energy use by urban and rural households and small industries, and includes traditional and modern fuel supplies, prefeasibility studies, pilot activities, technology assessments, seminars and workshops, and policy and research work.
- ***The Natural Gas Development Unit*** addresses gas issues and promotes the development and use of natural gas in developing countries through preinvestment work, formulating natural gas development and related environmental strategies, and research.

FUNDING

The ESMAP Program is a major international effort supported by the World Bank, the United Nations Development Programme, and Bilateral Aid from a number of countries including Australia, Belgium, Canada, Denmark, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

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ESMAP/OLADE

PROCEEDINGS OF THE REGIONAL SEMINAR ON

ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN

Kingston, Jamaica

July 3-7, 1989

Energy Efficiency and Strategy Unit
Industry and Energy Department
World Bank
Washington, D.C.

PROCEEDINGS OF THE

REGIONAL SEMINAR ON ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN, KINGSTON, JAMAICA, JULY 3-7, 1989

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ESMAP/OLADE

REGIONAL SEMINAR ON ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN

KINGSTON, JAMAICA

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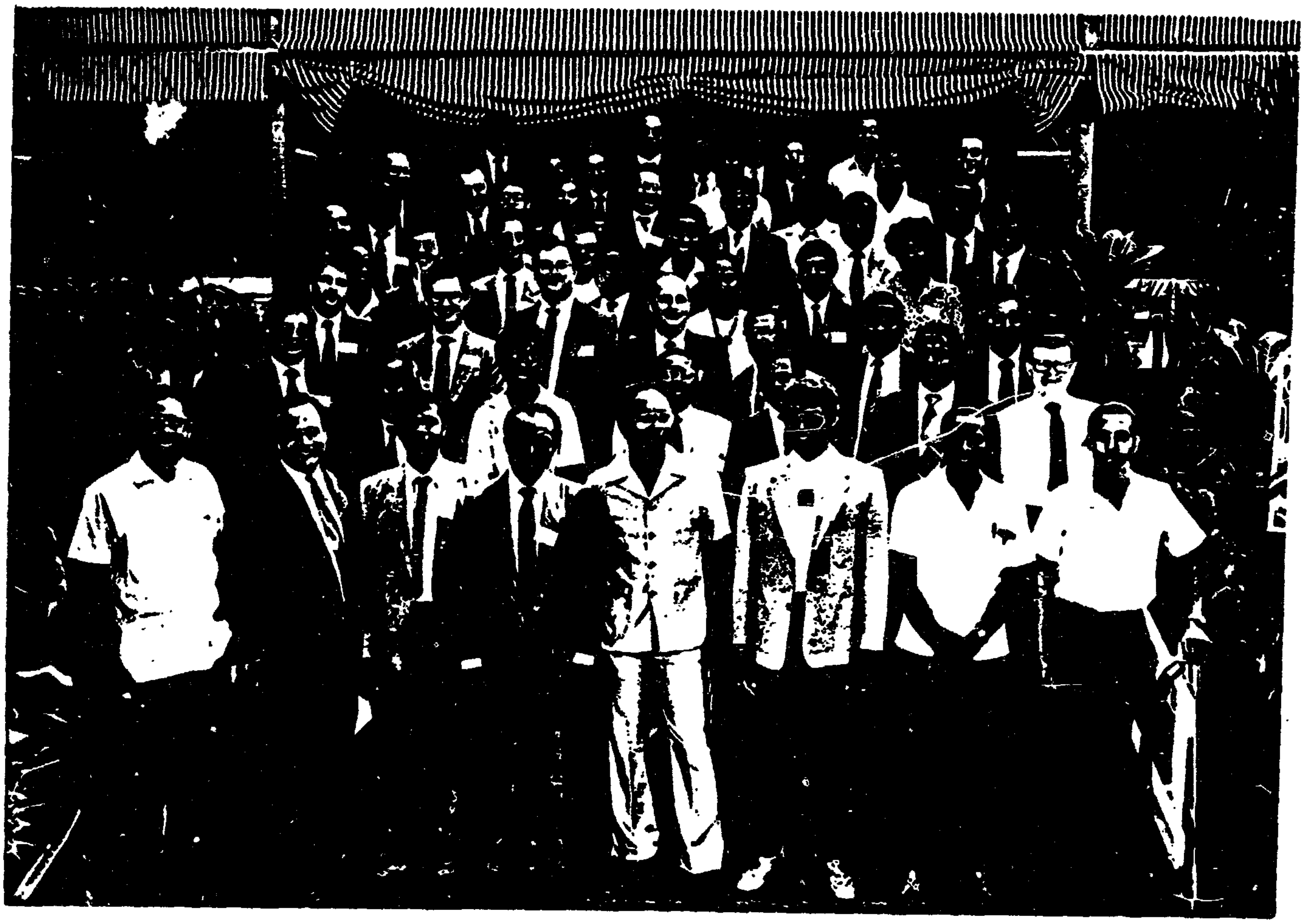

PREFACE

On July 3-7, 1989, the World Bank/UNDP Energy Sector Management Assistance Program (ESMAP) and the Latin American Energy Organization (OLADE), jointly sponsored a seminar for the Caribbean region on the reduction of losses on electric power systems. The purpose of the Seminar was to share with participants the experience of the two organizations on economic methods of reducing both technical and non-technical electric power system losses. Participants, drawn from 20 Caribbean countries, included high-level management personnel in electric utilities and senior civil servants who administer their governments' policies in the electric power sector.

ESMAP, the Energy Sector Management Assistance Program, is an international effort in the energy sectors of developing countries, sponsored by the World Bank, the United Nations Development Programme (UNDP) and several bilateral and other multilateral aid groups. As its name implies, ESMAP's major role is to provide technical assistance to developing countries in the efficient management of their energy sectors. OLADE, the Latin American Energy Organization, provides energy assistance to its member countries from Latin America and the Caribbean.

The expenditures for the Caribbean seminar were borne by the sponsoring agencies. ESMAP's costs were met from contributions to the program made by the Governments of Switzerland and the United Kingdom. Funds made available to OLADE by the European Community defrayed the expenses which OLADE incurred. The Government of Jamaica graciously hosted the week-long seminar in Kingston.

This volume contains papers prepared for the seminar. It has been compiled as a record of the proceedings of the seminar and in the hope that it may be of use to persons who were not participants in the seminar but are concerned with efficient power system operations, particularly in maintaining losses at economically acceptable levels.

INTRODUCTION

ESMAP findings in a number of developing countries indicate that electric utilities often issue invoices for less than 80 percent of the energy sent out from the generating stations. The 20 percent difference is classified as losses. In some extreme cases losses exceed 40 percent. In industrialized countries losses do not normally exceed 10 percent.

Power system losses may be divided into two categories, technical and nontechnical. Technical losses are those which result from current flowing through the transmission and distribution lines, transformers, customer serviced lines, etc. There are also nontechnical losses which are due primarily to human factors including such problems as consumer invoicing, accounting, metering or meter-reading errors, and power theft. Electricity losses represent an economic cost to the country since the resources used to generate and distribute electricity are not being utilized to the greatest productive advantage. They also represent a financial cost to the utility which is thereby deprived of revenues due to it for energy consumed.

ESMAP and OLADE Partnership

Much of ESMAP's previous work has been focused on making recommendations as to specific measures by which power system losses may be reduced and on preparing evaluations which indicate the approximate costs and benefits of the measures. ESMAP has extended its work in this area by presenting a series of seminars in power loss reduction to qualified personnel in developing countries. The first two of these seminars took place concurrently in Abidjan, Côte d'Ivoire, in November 1987. Participants were drawn from 26 sub-Saharan African countries. One of the seminars was presented in the English language, the other in French.

OLADE has also been active in promoting loss reduction in Latin America and hosted a seminar on this topic in October 1988 in Bogota, Colombia. Participants were drawn from the Spanish-speaking countries of the region. As a number of the English-speaking Caribbean countries are also members of OLADE, the organization was beginning to plan a similar seminar in the Caribbean when it was discovered that ESMAP was also planning in the same direction. It was decided that a joint seminar would not only make more efficient use of the resources available but would also demonstrate the commonality of purpose of these two organizations active in the regional energy sector.

ESMAP and OLADE agreed that the seminar would be targeted to participants drawn from senior management positions in electric utilities, particularly those persons with responsibility for power distribution and commercial operations. However, civil servants who monitor the performance of the utilities and/or determine electricity tariffs were also considered. In addition to the Anglophone countries of the region, Haiti and the former Dutch colonies were invited to nominate persons for participation in the seminar.

All participants expenses which resulted directly from the seminar were borne by the organizers. These expenses comprised the cost of travel and accommodations, including overnight accommodations en route to or from the seminar, where necessary, and the provision of a daily allowance to meet subsistence costs.

Seminar Objectives and Proceedings

The seminar was developed to meet four objectives. The foremost was to improve awareness of the economic and financial costs of power system losses. The seminar was also to be useful in indicating methods by which power system losses may be reduced to economic levels. Because the participants had some experience in confronting these types of problems and the sessions were intermingled with experts having worked on resolving these problems, the seminar was to be a forum for interchange of ideas on the subject. Finally, the meetings were to be opportunities to encourage innovative approaches to system efficiency improvement.

The seminar was presented in Kingston, Jamaica, July 3 to 7, 1989. There were 48 attendees from 20 countries, the countries represented being Antigua, Anguilla, Aruba, Bahamas, Barbados, Belize, Bonnaire, British Virgin Islands, Cayman Islands, Dominica, Grenada, Guyana, Haiti, Jamaica, Monteserrat, St. Lucia, St. Vincent, Suriname, Trinidad and the Turks and Caicos Islands. Thirty-three of the participants are employed by electric utilities and 15 are in the civil service. Five women were included among the participants.

The topics for the formal sessions of the proceedings included the relationship between national development and power losses, the energy balance of the Caribbean, sources of technical and nontechnical losses, identification and reduction of technical and nontechnical losses, economic evaluation of loss reduction projects, computer calculation of technical losses, and efficient operation of diesel generating stations.

A major focus of the presentations was the economic appraisal of losses, both technical and nontechnical.

They further recognized that projects designed to reduce losses always require investment of some funds. Discussions centered on the fact that the investment required to reduce losses by a given increment increases as the losses get lower. A point, thus, will be reached at which the investment required to produce further reduction in losses will exceed the benefits which will derive from the reduction in losses. this point will be the economic level of losses and is dependent on a number of factors peculiar to each system.

Participants agreed there is no level of loses which can be selected as the standard to be used as the goal of all utilities. Each loss reduction project must, therefore, before implementation, be subjected to careful cost benefit analysis to ensure that the benefits are commensurate with the costs. The methodologies by which the costs and benefits of loss reduction projects are evaluated absorbed much of the time devoted to the formal sessions of the seminar.

Three countries in the region, Jamaica, Barbados, and St. Vincent presented case studies of their own experience in loss control. The case studies indicated the successes and frustrations which each utility had experienced and the programs being developed to deal with the areas in which improvement was still required. These case studies were included as one of the means by which the objective of providing a forum for the useful interchange of experiences in and ideas for loss reduction programs could be achieved.

Field trips also formed part of the seminar agenda. Jamaica Public Service arranged for visits to be made to a number of its installations which proved to be of great interest to many of the participants. These installations included the Rockfort Diesel Barge, the System Control Center, and the Roaring River Hydroelectric Station.

Evaluation and Future Programs

Participants were asked to evaluate the relevance and effectiveness of each session and to assess the extent to which the seminar achieved its overall objectives. The average ratings on all counts was encouragingly high, above 70 percent. Among the recommendations made by participants was a similar seminar on the topic of efficient thermal generation, both diesel and steam, which they believed would be of benefit to the regional utilities.

ESMAP and OLADE were satisfied with the success of their initial joint effort in seminar presentation. The various suggestions made by the country delegates could very well form the foundation on which ESMAP and OLADE will build their next joint venture in the Caribbean.

REGIONAL SEMINAR ON ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN
Wyndham Hotel

Kingston, Jamaica : July 2-7, 1989

SEMINAR AGENDA

DAY/DATE	TIME/HOURS	ACTIVITY	SPEAKER
SUNDAY JULY 2	1500-1800	Registration	
	1900-2100	Reception	
MONDAY JULY 3	0800-0845	Registration	
	0900-0930	Opening Address - OLADE	Gabriel Sanchez-Sierra, Executive Secretary, OLADE
	0930-1000	Opening Address - ESMAP	Alastair J. McKechnie, Division Chief, World Bank
	1000-1030	Opening Ceremony	Orville W. Cox, Executive Chairman, Jamaica Public Service CO.
	1030-1045	Break	
	1045-1130	Power Losses and Development Levels	Trevor Byer, Principal Evaluation Officer, World Bank
	1130-1230	Energy Balance of the Caribbean	June Budhooram, Chief, Energy Balance Program, OLADE
	1230-1400	Lunch	
	1400-1500	Sources of Losses	Winston Hay, Senior Power Engineer, World Bank
	1500-1515	Break	
	1515-1615	Important Loss Parameters	Winston Hay, Senior Power Engineer, World Bank
	1615-1630	General Instructions	

DAY/DATE	TIME/HOURS	ACTIVITY	SPEAKER
TUESDAY JULY 4	0900-0945	Case Study	Huntley Higgins, Director, Engineering & Projects; Raymond Silvera, Director of Districts, Jamaica Public Service Co. Ltd.
	0945-1030	Demand Management	Alfred Gulstone, Senior Power Engineer, World Bank
	1030-1045	Break	
	1045-1145	Efficient Diesel Generation	Klaas Kimstra, Engineering Manager, Stork-Werkspoor Diesel, The Netherlands
	1145-1245	Ways to Reduce Distribution Losses	Barry Kennedy, Consultant, Electricity Loss Reduction
	1245-1400	Lunch	
	1400-1500	Engineering Economics of Loss Reduction Project	Barry Kennedy, Consultant, Electricity Loss Reduction
	1500-1515	Break	
	1515-1615	Problem Solving	Barry Kennedy, Consultant, Electricity Loss Reduction
	1615-1630	Announcements, General Discussions	
	1930-2200	Dinner	Guest Speaker, Rt Hon Hugh Small, Minister of Mining and Energy
WEDNESDAY JULY 5 Installations:		All Day	Field Trip to Jamaica Public Service Co.

- Roaring River Hydro Power Station
- Lunch
- Rockfort Diesel Power Station
- JPS System Control Centre

DAY/DATE	TIME/HOURS	ACTIVITY	SPEAKER
THURSDAY JULY 6	0900-0945	Cost/Benefit Analysis of Non-Technical Loss Reduction Programs	Luis Gutierrez, Senior Energy Economist, World Bank
	0945-1045	Identification and Classification of Non-Technical Losses	Renato Cespedes, Professor Universidad Nacional de Colombia
	1045-1115	Break	
	1115-1215	Evaluation of Non-technical Losses	Angel Zannier, Manager, Electricity Program, OLADE
	1215-1400	Lunch	
	1400-1500	Corrective Measures for Non-technical Losses	Willy Pacheco, Operational Manager, Bolivian Power Company
	1500-1530	Break	
	1530-1630	Case Study	Claude Franklin, Chief Distribution Engineer, Barbados Light and Power
	1630-1730	Announcements and General Discussions	
FRIDAY JULY 7	0900-1030	Micro-computer Calculation of Technical Losses	Okorie Uchendu, Power Engineer, World Bank
	1030-1045	Break	
	1045-1230	Panel Discussion on Loss Reduction	Moderator: Rafael Moscote, Division Chief, World Bank
	1230-1345	Lunch	
	1345-1445	Case Study	Lennox Morris, Planning Engineer, St. Vincent Electricity Services Ltd.
	1445-1500	Break	
	1500-1600	Course Evaluation and Certificate Presentations	

REGIONAL SEMINAR ON ELECTRIC POWER LOSS REDUCTION IN THE CARIBBEAN

Wyndham Hotel

Kingston, Jamaica - July 2-7, 1989

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REGIONAL SEMINAR ON ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN

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REGIONAL SEMINAR ON ELECTRIC POWER LOSS REDUCTION
IN THE CARIBBEAN

OPENING STATEMENT

By

Gabriel Sanchez-Sierra, Executive Secretary, Latin American Energy Organization

July 3, 1989 Kingston, Jamaica

Mr. Chairman, Ladies and Gentlemen.

For the OLADE (Latin American Energy Organization) Secretariat, it is a source of great satisfaction to be able to welcome all of you to this Seminar on Power Loss Reduction for the English-speaking Caribbean countries, which the Government of Jamaica has so generously agreed to host and the ESMAP (Energy Sector Management Assistance Program) Division of the World Bank has co-sponsored with us for the benefit of the whole region.

The presence of delegations from both OLADE members and non-members is yet another eloquent expression of the broad-based support for the integrationist principles which mark the Latin American energy organization's programs and activities throughout the region.

As all of us here today are aware, that the Latin American and Caribbean countries are immersed in an acute economic crisis, within which the energy sector has reached a situation of stagnation and even deterioration. There are no simple, individual solutions to our problems; the solution will have to come through a true integration process based on strong, united actions.

The energy problems must be solved within the complex overall socioeconomic panorama for the region and, since the problems are structural in nature, the solutions must be structural as well.

A new energy development strategy must be found: a strategy more in line with the countries' macroeconomic context and also their energy resource endowment. This will require changes in the supply structure and also improvements on the demand side. Efficient production will in turn be achieved through suitable policies for the optimal expansion of power facilities and through optimized system operation.

It is in the context of these considerations that OLADE has identified several areas of action geared to improving the efficiency of the power subsector in the countries of the region. For example:

- System planning
- Strategic financial planning
- Optimal system operation
- Effective management
- Tariff policies

- System rehabilitation and
- Control of losses

Any improvement in efficiency, in any one of the components of a power system, will have repercussions for the subsector as a whole. These will then be reflected at the level of the global energy sector and, finally, at the macroeconomic level.

The reduction of power losses at the level of end-users, through programs of rational use of energy, combined with programs geared to demand management and to the reduction of losses in the transmission and distribution systems and in the generation systems, can together have significant repercussions for the power subsector overall.

At the level of the energy sector, these results will imply a reduction in the use of primary energy and, consequently, deferring some of the planned power system investments.

Finally, there may be various types of repercussions at the macroeconomic level. Some of the scarce financial resources availabe to Latin American and Caribbean countries may be freed for use in top-priority areas, i.e. social sectors. There may also be fuel surpluses in the exporting countries, and a lighter fuel bill in the current account of the importing ones.

Global programs of power loss reduction prove to be highly effective. OLADE has done preliminary estimates of their quantitative worth, based on information from the energy balances for the countries in the region. In this exercise, assuming power consumption growth rate of 6% annually over a 15-year period 1983-1997, it was found that in the most pessimistic loss reduction scenario an average of 190,000 GWh can be saved per year - and 87,000 MW during the 15-year period.

Considering an economic value of US$30,000/kWh as the average production cost and some 1,750 dollars/kW as the investment cost, the regional potential for savings would be around US$240 billion over the period. These figures clearly demonstrate the importance of the topics to be discussed at this Seminar. However, investments have to be made and in any case, they would be in the order of one hundred billion dollars.

In closing, may I take this opportunity to express my sincere appreciation to the Jamaican Government officials, in particular to the Minister of Mining and Energy and the Jamaican Public Service Company (JPS) for their collaboration in the organization of this event; and on behalf of the OLADE secretariat, I would also like to thank all of the delegates for their interest in attending this Seminar, which consitutes one more step on the road to integration among the Latin American and Caribbean countries.

Finally, I would like to specially thank the ESMAP Division of the World Bank, which financed the participation of all the non-OLADE member countries at this Seminar, which also marks the initiation of joint activities between our institutions, in an effort to optimize our common goals in the Caribbean Region.

REGIONAL SEMINAR ON ELECTRIC POWER LOSS REDUCTION IN THE CARIBBEAN

OPENING STATEMENT

by

Alastair McKechnie, Chief, Energy Efficiency & Strategy Unit, World Bank

July 3, 1989 Kingston, Jamaica

Mr. Chairman, Ladies and Gentlemen.

It gives me great pleasure to welcome you to this seminar on behalf of the World Bank and ESMAP. This is the second seminar on power efficiency that we have held. The first was held in Africa in November 1987. In our view these seminars offer an excellent opportunity for us to share the experience we have gained in studying how to improve the efficiency in electric power systems in more than 20 countries. It is also an opportunity for you, the participants, to renew contacts among each other and to exchange experiences on loss reduction.

As you may know, the acronym ESMAP stands for Energy Sector Management Assistance Program. ESMAP is a joint program of the World Bank, the United Nations Development Programme and bilateral donors. ESMAP provides technical and policy advice, performs investment studies and research, and carries out training activities.

We are conscious that the demand on ESMAP services is much greater than we can meet. In a region such as this there are many countries which are often small, so that it is difficult to meet individual needs. Regional seminars such as this enable us to provide a basic service that we hope will encourage countries that we otherwise could not work in to make progress in reducing system losses.

My talk this morning is in two parts. The first concerns some of the issues that we believe are important in the effective development of the power sector. Improving efficiency is of course one of the most important. The second part is about what ESMAP is doing to address these issues.

In 1988 the World Bank published the results of a review of about twenty years of lending in the electric power sector. This review confirmed what many of us active in the sector had suspected. Irrespective of how efficiency is defined, there had been a general trend for efficiency to decrease. For example, financial performance had become steadily worse. Transmission and distribution losses generally had risen. In many countries losses are now between 20% to 30% of net generation, and in some systems approach 50%. Quality of service -- reliability, voltage levels, for example -- had deteriorated. Project implementation had been subject to delays and cost overruns.

What have been the effects of this deterioration in utility performance? As you are aware the problem of servicing external debt has become acute, especially in the Latin America and Caribbean region. Available data indicate that the impact of the power sector on indebtedness has been significant. Electric power investment has often accounted for 15-25% of all investment and as much as 35% of external debt. In many countries the "debt crisis" in a large part was due to power investment that was excessive for several reasons, such as

- demand that was over-stimulated by low prices;
- errors in demand forecasting;
- excessive reliance on large capital intensive plants, especially hydro, that resulted in investment programs that were difficult to adjust as circumstances changed;
- the overlooking of low cost options such as natural gas based generation, rehabilitation and efficiency improvements; and
- investment in generation was needed to cover increasing technical losses in generation and distribution.

Furthermore, the deteriorating financial performance of utilities has caused the power sector to rely on government financial handouts that may be direct or disguised through tax exemptions and subsidized credits. This has affected both the financial solvency of the government itself and the autonomy and morale of utilities. Non-technical losses -- theft, metering and billing inadequacies -- have contributed to these financial problems.

As well as producing economic benefits, raising efficiency is one of the most effective means for reducing the burden of energy use on the environment. Lowering the ultimate fuel input or investment requirements to supply a kilowatt-hour of useful energy to the consumer through higher efficiency, usually leads to less air and water pollution, and in some cases can postpone the impacts on forests and human settlements arising from the construction of hydro reservoirs.

While the consequences of inefficiency in electricity supply may be serious, this seminar will demonstrate that the costs of reducing losses are generally not great. A dollar spent in improving efficiency may provide as much as three to ten times more capacity than that spent on construction of new plants.

Nevertheless, we should not lose sight of the fact that improving efficiency in the electricity supply industry is not just a simple technical matter. Engineers in power utilities are well educated intelligent people -- in many respects the technological elite of the country -- who are usually aware of the options for loss reduction. However, they need the correct set of incentives and the support of governments if a successful program is to be implemented. We have found repeatedly that utilities with high losses are characterized by weak internal organization and a poorly defined relationship with the government. Reducing non-technical losses requires decisive action to impose sanctions on those stealing electricity and to root out dishonesty among utility staff involved in meter reading and billing. Governments need to hold utility managers accountable for the efficiency of electricty supply. Governments also need to resist the urge to meddle in management matters and to provide the resources needed to do the job.

What is ESMAP doing to help increase efficiency in the power sector?

Our range of activities is broad, including overall assessments of energy policy, studies of strategy, efficiency and management in the various energy supply subsectors, supporting energy conservation in the industrial and other sectors, determining how to meet the energy requirements of low income households, and evaluating new and renewable technologies.

ESMAP services are provided on a grant basis for high priority activities that are wanted by the recipient countries, are consistent with an efficient energy sector strategy, and are capable of financial support from the program donors. We are pleased to consider requests for ESMAP assistance from countries directly, and activities are also identified by donors and the World Bank operational staff.

ESMAP activities increasingly involve active participation by the recipients. In power efficiency work we are ensuring that beneficiaries obtain relevant software and hardware to analyse technical losses. Staff are trained in their use and initially work closely with the ESMAP team to identify actions to reduce losses. Our aim is for this activity to carry on after the completion of ESMAP's work.

As we are accountable to donors for the effective utilization of funds provided, an ESMAP task manager is responsible for the overall activity, and we insist that a concrete output is produced, e.g. a report detailing investments and policy and administrative measures to reduce losses. The ESMAP team typically consists of the task manager, maybe one other of our staff, and a number of short term international or local consultants.

ESMAP can not function without donor support and we are particularly grateful to the Governments of Switzerland and the United Kingdom which have partly funded this seminar through their contributions to ESMAP. We are also pleased that this seminar is a joint effort with OLADE. We welcome this opportunity to strengthen our cooperation. UNDP has supported the seminar through its contribution to ESMAP and through the excellent assistance given by the UNDP resident mission in Jamaica. Finally, and certainly not least, this seminar could not have taken place without the support of the Government of Jamaica and Jamaica Public Service Company.

To conclude, I suspect much of what you will hear this week is not new to you. However, I believe the strength of the ESMAP approach to power efficiency is to bring together a number of elements to form a field of activity -- power efficiency -- that produces wide ranging economic, financial, and environmental benefits. I hope you find the seminar instructive and useful and that it leads to sustained improvements in the efficiency of your power systems.

Thank you.

REGIONAL SEMINAR ON ELECTRIC POWER LOSS REDUCTION IN THE CARIBBEAN

OPENING ADDRESS

By

Mr. Orville W. Cox, Executive Chairman, Jamaica Public Service Co. Ltd.

July 3, 1989

Mr. Chairman, the Hon. Hugh Small, Mr. Alastair McKechnie, Chief of Energy Efficiency and Strategy at the World Bank, Mr. Gabriel Sanchez-Sierra, Executive Secretary, OLADE; visiting participants to this Seminar; Ladies and Gentlemen.

I must first of all express the pleasure on behalf of the Jamaica Public Service Company for the invitation to participate in this Seminar on electric power loss reduction for utilities in the Caribbean. Thanks to the World Bank, UNDP and OLADE which have seen fit to host a conference of this nature, and I am sure I am expressing the sentiment of other electric utilities present here, as power loss of any kind does have a debilitating effect on the financial viability of any electric utility company. The interest which your organizations have shown in the development of enterprises such as ours is heartening and for that we are extremely grateful.

While you and our Caribbean colleagues are here with us in Jamaica, we hope you will feel that you are a part of our family and would be pleased to have you visit with us to see any aspect of our operations which may be of interest to you. I am sure that we will all find the deliberations fulfilling.

The matter of electric power loss from both the technical and non-technical stand point has, for a long time, been of great concern to the Jamaica Public Service Company. This has resulted in loss of revenue amounting to millions of dollars which we have continually tried to recover with marginal success. At present, the rate of power losses accruing to the JPS stand at some 20.1%.

In this regard a number of studies have been undertaken with a view to determining how best this problem can be addressed.

In August 1986, the Jamaica Public Service Company commissioned the firm of EBASCO Corporation of the United States of America to undertake a study of losses in the electricity system in Jamaica and to make recommendations on how these losses could be reduced.

The study was completed in July 1988 and presented to the Company for consideration. Its main focus concerned the technical losses in the transmission and distribution systems.

This report, however, fell short of our expectations as the study was restricted to an evaluation of the 13.8 kV and 69 kV transmission systems, the primary distribution feeders and the distribution transformers. The report also stated that the main emphasis was placed on the primary distribution feeders as these would yield the highest benefit to cost ratio.

Briefly, the EBASCO Corporation's recommendations to us proposed the conversion of a number of distribution feeders from 13.8 kV and 12 kV to 24 kV. This suggestion was not new to us as we had already been carrying out such a program across the island with funding from the World Bank.

The Management of the Company felt that more could have been done in the examination of the issue of power losses and this led to the establishment of an in-house committee comprising senior engineers to look at other factors which to us, were important if we were indeed serious about reducing electric power losses. Chief among the Committee's concerns was a study of non-technical losses as they affected the Company's operations.

This Committee drew on the experiences of the Company's Revenue Protection Department, a unit which was officially established in 1987 primarily to deal with those losses which are not confined to the tramsmission and distribution systems. The Committee in their report identified that approximately 12% of all customer accounts, supplies or metering systems were in error thereby leading to revenue loss to the Company. Main areas contributing to these losses were:

- defective meters
- tampered and backed meters (theft)
- incorrect meter multipliers
- line-taps including meter by-pass
- incorrect meter installation and
- unbilled metered supplies.

We are well aware that non-technical losses are not the major contribution to the shortfalls in revenue to the Company; yet, we nevertheless felt that it was important enough for the Company to focus its attention in this area to be able to meaningfully minimize the problem.

Over the past two years the Company has, through the efforts of the Revenue Protection Department, made considerable progress in billing a total of Jamaica $4.5 million in non-technical losses. Of this amount Jamaica $3.3 million has actually been collected by the Company. Overall effects of this will result in an expected annualised revenue of Jamaica $1.8 million per annum.

Much of what I have made mention of in my address I am sure will be dealt with in greater detail by the Company's two presenters Mr. Raymond Silvera, Director of District Operations and Mr. Huntley Higgins, Director of Engineering. Both gentlemen have been very involved in the activities of the power loss program and are competent to share with you more in-depth information as to what the Company is doing in this regard.

The Jamaica Public Service Company realizes, as I have said in my opening comments, that we are not alone in the problem of addressing power losses. We have from time to time, in our own quest to find solutions to our problems, been exposed to the statistics of other countries in, and outside of the region.

The Caribbean Electric Utility Surveys for 1987 and 1989 in giving an account of electric utilities in the English-speaking Caribbean has shown a number of countries whose power loss situation compare closely with our own here in Jamaica. We note in 1987 that islands like Grenada experienced a level of 19.77% in power losses,

St. Kitts - 27.9% in power losses
St. Vincent - 21.99% and
Trinidad & Tobago - 19.23% in power losses.

They, like Jamaica, fall in the higher percentage power loss-group in this part of the Caribbean. The report for 1989 is by and large similar except for Trinidad and Tobago which has shown a marked reduction from the 19.23% figure in 1987 to 11% in 1989. We also note the current figures for our fellow territory Guyana (which was not included in the 1987 Report) being in the region of 25% in power losses. These facts should make for interesting analysis during your deliberations.

A seminar such as this one, therefore, should be taken as the golden opportunity for Caribbean utilites to examine and identify, in a spirit of co-operation, problems which for them are common in some cases and unique in others. By the sharing of ideas and technical expertise bold attempts could be made to reduce electric power losses to acceptable levels.

The matter of co-operation among regional countries is one which has come to the fore many times in the last two years, and there is the ever-increasing indication that Caribbean countries, if they are to realise positive social and economic development, will have to become committed to collaboration at a much greater level.

In 1987, this Company along with the two Italian firms ANSALDO and ENEL hosted a regional conference for co-operation between electricity generating companies on Power Plant Maintenance here in Kingston. Much was achieved by way of the exchange of ideas and experiences of participating countries. What, however, stood out on that occasion and gained the unanimous approval of the delegates present, was that there was a need for the establishment of a body of Caribbean electricity generating companies to promote more intra-regional training and technical assistance between these companies. It was at that conference that it was suggested that a committee be set up to draft specific proposals with a view to making this a reality.

More recently, the need for cooperation has been reinforced even further with the devastating Hurricane 'Gilbert' experience. In addition to the assistance given to us by the more developed countries such as the United States, Britain, Canada and Italy, our Caribbean neighbours like the Bahamas, Bermuda similarities which exist between our country and their own, were able to give invaluable assistance in the restoration of power to several sections of our island. Once again, we all saw the need to forge more formal links of cooperation between our countries.

It is my impression, however, that we have not moved swiftly enough in making this ambition a reality. If we hope as developing countries to provide a necessary service to consumers at the best possible cost, we will meet the particular needs of our region. It might, therefore, be prudent for us to initially look to training as one area which provides opportunities for this increased cooperation. May I suggest that this be done on a formally structured basis or be pursued through the exchange of staff at various levels within sister utility companies.

In conclusion, let me say that it is my fervent wish that your discussions here at this Seminar will break new ground in finding solutions to reducing the awesome problem of power losses in electric utilities as we are all well aware of the havoc which it plays with the revenues of our companies. Let us be positive about it. The challenge is ours, my friends, and with will and purpose these goals can be achieved.

Once again, may I welcome you all here and wish you every success in your deliberations. It is with great pleasure that I now declare this Seminar on Electric Power Loss Reduction officially open.

POWER LOSSES AND DEVELOPMENT LEVELS

by

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This paper was prepared for the Caribbean Power Loss Reduction Seminar held between 3-7 July 1989, in Kingston, Jamaica, and sponsored jointly by the Latin American Energy Organization (OLADE) and the UNDP/World Bank Energy Sector Management Assistance Program (ESMAP).

POWER LOSSES AND DEVELOPMENT LEVELS

I. INTRODUCTION

1.1 For the past several decades power development has been at the forefront of development priorities in developing countries. The two primary objectives in focussing on this essential infrastructure were:

(i) to improve economic growth and development prospects; and

(ii) to enhance living standards--especially in rural areas and slum areas of urban centers.

1.2 Changes, however, since the early 1980s, in both international and domestic LDC financial markets have tended to force a shift in priorities in the power sector in most LDCs towards much greater concentration on efficiency improvements, greater sector financial savings, reduced investment programmes, and, as a consequence, somewhat lesser emphasis on enhanced coverage.

1.3 Typically, however, we hear about how many hundreds of billions of dollars in investment are going to be needed in the 1990s by LDCs to finance the several hundred thousand megawatts of new capacity that are expected to be commissioned. These numbers mean nothing in a Caribbean context and, hence, are of little relevance to this region, so I will not bore you with them. What is of relevance to this region, in the framework of the power sector, is that what one believed was affordable during the 1980s is likely to be less so in the

1990s. This is because of the high share of foreign costs in power sector investment in the region and the uncertain foreign exchange earnings expected from regional economies. Second, because of the adjustment policies in the region the power sector can no longer indulge in the past luxury of negatively impacting the public sector fiscal deficit, implying significantly increased sector savings are called for. What all of this means is that the fulcrum about which power sector policy has to balance in the 1990s is that of improved efficiency and higher savings.

1.4 We are going to hear in this Seminar many presentations and discussions about how to equip ourselves and our companies better to reduce power losses. What I wish to focus on, however, is setting a context for the effort we will undertake this week. The context necessarily will be broad, since too often we plunge into a world of details without understanding the critical relationships between first, the task at hand (which we are trying to solve); second, the tools available to address the problem; and third, and above all, the setting and environment within which the problem exists.

1.5 In this presentation there is first a discussion of the broad characteristics of the "post-generation" losses in power systems along with very rough estimates of the economic costs of power losses within the region. This is followed by a review of the key role of the socio-economic context/environment in influencing non-technical losses and the degree to which these losses can be reduced given the context in which the utility functions in the society which it serves. What is especially highlighted here is that there are limits to which non-technical losses can be lowered in certain socio-economic contexts. The focus then shifts to the regulatory context, since there are important contributors to losses stemming from this area. In many ways, one of the problems of the past 15 years has been that since the power sector in most LDCs was taken over by state companies, the degree of attention paid to regulatory issues in the sector has declined dramatically on the part of most governments. The fourth area then discussed concerns the utility context, through which yet another layer of insights can be discerned. The final focus is then that of the consumer context.

II. POWER LOSSES AFTER POWER GENERATION

(a) Technical and Non-Technical Losses

2.1 Power losses occurring after generation have generally been classified into two groups--the technical component and the non-technical component. The technical losses represent the energy that cannot be consumed because of the physical characteristics of the transmission and distribution (T&D) system. Such losses result in financial losses and also economic costs; the latter since less resources are needed to meet demand if the technical losses are reduced to an optimal level which can vary between 9%-11% of net generation, dependent on the T&D system's characteristics. An important quality of technical losses is that they can be measured.

2.2 Non-technical losses, in contrast, are not measured directly but represent the difference between total measured losses and the measured technical losses; with the total losses being another difference, this time between another two measured quantities, namely, net generation and billed sales. Essentially, the non-technical losses represent the sum of consumption and billing losses. The former accounts for the fact that not all consumption is recorded, and the latter that not all recorded consumption is billed accurately.1/ Since non-technical losses represent consumption that is not paid for--i.e. free, it has the important effect of increasing consumption and demand. This rising demand, in turn, could aggravate the technical losses. This could occur if the peak-load demand pattern for the stolen energy is essentially similar to that for the utility system as a whole. The net result being that the increased demand arising from growing non-technical losses would require system capacity to be expanded earlier. This indicates that non-technical losses represent an economic cost to the society as well as a major financial cost to the utility and those consumers not enjoying free electricity, since they, in effect, pay a higher tariff.

(b) Power Losses in Different Markets

2.3 Table 1 shows estimates of energy losses and their structure (when known) for several Caribbean islands, as well as for three major markets in Colombia and the State of Uttar Pradesh in India. The wide range of total loss levels in the Caribbean is to be noted, despite the fact that the data cover a wide time period between 1980 and 1986. As far as the Caribbean is concerned, total losses range from the low end of the scale, around 9%-10% of net generation typical of the Barbados and Trinidad systems, to about 30% in Haiti and the Dominican Republic.

1/ "Non-Technical Losses" by R. Aubin and D. Daoust, Paper presented to UNDP/World Bank Seminar, November 1987, on "Reducing Power System Losses in Africa."

Table 1: STRUCTURE OF ENERGY LOSSES IN VARIOUS MARKETS
(Percent of Net Energy Available)

Market	Year	Losses Technical	Non-Technical	Total
EEEB (Colombia)	1976	11.6	4.3	15.3
EEEB "	1979	10.7	7.6	18.3
EEEB "	1986	11.3	13.2	24.5
EPM "	1976	9.4	8.3	17.7
EPM "	1979	11.9	6.3	18.2
EPM "	1986	9.6	10.4	20.0
EMCALI "	1976	9.8	0.4	10.3
EMCALI "	1979	9.8	1.7	11.5
UTTAR PRADESH (India)	1988	20.0	8.0	28.0
ST. LUCIA (North)	1982	14.7	10.8	25.5
ST. LUCIA (South)	1982	12.2	7.4	19.6
BARBADOS	1981	N.A.	N.A.	9.0
ST. VINCENT	1982	12.5	10.8	23.3
GUYANA	1981	16.0	8.0	24.0
TRINIDAD & TOBACO	1984	N.A.	N.A.	10.0
JAMAICA	1986	N.A.	N.A.	19.0
HAITI	1986	N.A.	N.A.	32.0
ANTIGUA AND BARBUDA	1981	N.A.	N.A.	22.0
GRENADA	1981	N.A.	N.A.	19.0
BELIZE	1980	11-12	4-5	16.0
DOMINICAN REPUBLIC	1986	N.A.	N.A.	30.0

2.4 What is the estimated cost of these losses in the region? In arriving at this, of course, the very different sizes of systems across the region is very relevant since the two largest public systems, those of the Dominican Republic and Trinidad & Tobago, are at opposite extremities on the scale of total losses. Based on all islands in the region, except Cuba, Puerto Rico, and the U.S. Virgin Islands, but including Belize and Guyana, estimated total losses in 1986 were around 2,000 GWh, representing around 19% of gross generation. This would imply that regional power losses would have been about US$160 million in 1986, around US$60 million (or 38%) of which can be considered as capable, in theory, of being captured as revenue by the power sector.

2.5 When one turns to power loss trends over time this is shown in Table 2 2/ for some sixty to seventy LDC utilities over the period 1973-1987. Loss levels there have been broken down by system size. What is of relevance is the systematic increase in losses over the period for all systems, except the very large ones, i.e. those representing a market of more than 50,000 GWh. In this context, it should be noted that there are few systems in LDCs corresponding to this last category--e.g., in all of South America only the Brazilian system is in this bracket! The results in Table 2 are also shown in Figure I, which illustrates that the smallest systems have tended to have the highest losses, though the differences between losses in small and medium-large systems has not been necessarily statistically significant. Figure II shows the breakdown by regions of the world. What is significant here is the explosion in loss levels in Latin America in the 1980s as the adjustment process has unfolded.

Table 2: AVERAGE POWER SYSTEM LOSSES /a
(LOSSES/CONSUMPTION)
(Percent)

System Size /b	Period	1973-77	1978-82	1983-87
Small		20	22	26
Medium		22	21	26
Medium-Large		16	17	19
Large		25	22	19
Total /c		20	21	24

/a Based on annual weighted averages of 51 to 71 utilities.
/b Classification based on 1986 system generation.

Small -- less than 2,000 GWh
Medium -- 2,001-10,000 GWh
Medium-Large -- 10,001-50,000 GWh
Large -- more than 50,000 GWh

/c Weighted average (by GWh).

Source: "Technical & Non-Technical Power Losses in Developing Countries," by G. Schramm, World Bank, 1988.

2/ "Technical and Non-Technical Power Losses in Developing Countries," by Gunter Schramm, November 1988.

III. THE SOCIO-ECONOMIC CONTEXT OF LOSSES

3.1 This is the overriding context in which system losses need to be viewed. If we forget this framework the basis of the analysis becomes flawed. Though there are risks in generalizations, most evidence shows that the levels of losses are inversely proportional to the development level of the society (service area) served by the power system. In other words, the lower the development level the higher the losses and vice-versa. Empirical evidence of this is shown clearly in Figure III, where total losses are indicated as a function of per capita national income between 1973 and 1987. In a way, the level of power losses becomes yet another indicator of development (like infant mortality, etc.) within the service area served by the utility company. Regrettably, hard data are not available to show how the different components of total losses, namely, the technical and non-technical, are separately affected by declining per capita national incomes, though there are some indications that the non-technical component rises more rapidly with falling income as power theft increases through illegal connections and meter tampering.

3.2 Of course, theft and fraud are endemic to the human condition, with the only differences within and between societies being what is stolen, by whom, and in what amounts? One only has to look at the recent stock market insider trading scandals and indictments in the USA, where billions of dollars have been involved, to recognize the veracity of this rudimentary observation. To the occupant of a third world urban slum, stolen electricity is likely to have the same relative monetary value as modest levels of embezzlement would in the world of white collar bureaucrats. Recognizing that we are simply dealing with different manifestations of the same phenomenon is an essential element of defining the problem. Naturally, when faced with increased levels of stolen electricity it is expected that strategies based on more intensive use of tamper-resistant components of distribution systems is likely to reduce somewhat the consumption loss element of the non-technical losses. However, we delude ourselves if we believe that mere "technical fixes" can overcome a problem of this nature. One expects that beefed-up physical safeguards would be an element of the remedies enacted but what becomes more challenging is trying to judge, for a given service area served by a particular company in a society at a particular development level, what is the level (x%) at which non-technical losses can be reduced to and sustained at?

IV. THE REGULATORY CONTEXT OF LOSSES

4.1 The element of non-technical losses that is aggravated by regulatory measures, or the absence thereof, represents a more amenable problem. There is one classic example I have come across in a major South American country. In this utility's service area about 1 in 5 residential subscribers in 1986 possessed legal connections but had no meters since this is not called for in the law! Even if such subscribers had had load limiters installed the uncertainty in monthly energy consumption for the 120,000 such subscribers would be very high. Yet in making an estimate of "non-technical" loss allocations by sources, shown in Table 3 below, the contribution arising from "service with no meters" is uncharacteristically low at 1.6%.

Table 3: ALLOCATION OF "NON-TECHNICAL" LOSSES FOR A SOUTH AMERICAN UTILITY - 1986
(Percent of Net Generation)

Service with no Meters	-- 1.6%	Fraud	-- 9%
Illegal Connections	-- 2.1%	Other	-- 0.3%

Total "Non-Technical Losses in 1986 - 13.0%

V. THE UTILITY CONTEXT OF LOSSES

5.1 There are a number of issues that arise when viewing losses from the utility perspective. First among these is the degree to which the company has a profitability incentive. This does not mean that it has to be privately owned. However, if it is state-owned, as most third world power companies are today, then the company and its management need to have a high degree of autonomy from the Government. Allied to such autonomy, the company must have as its goal the ability to cover all of its costs, including contributions to new investment, if it is to view the challenge of loss reduction in a context that serves the company's own financial interest. Clearly, the greater the extent that the company operates with direct government budgetary transfers, the less there is any incentive on the company's part to improve its efficiency in the form of reducing losses. In other words, unless the broad objective of profitability is at the forefront of management's vision, loss reduction can fail to ignite a determined action programme. In my judgment, this is an area in which more attention must be focussed in the design of loss reduction programmes. It has nothing to do with hardware but everything to do with the software of human and corporate incentives. What is the correlation between power loss levels and government financial support?

5.2 It is at this juncture that one then runs into the second aspect of the utility context, this being the level of staff morale, at all layers, to which is intimately linked--the quality of their remuneration relative to the rest of the society. Naturally, in this framework the utility cannot completely divorce itself from the realities of the society in which the company exists. However, some degree of divorce has to occur, the more so the lower the development level of the country. This is imperative given the skills the utility staff must possess if it is to be capable of discharging its functions. Clearly, it becomes something of an untenable battle, attempting to reduce the billing loss element of the non-technical losses, beyond what is achievable through use of upgraded technology, if the above types of issues have not been satisfactorily settled.

5.3 The above observations can be considered as necessary conditions for a successful attempt to be made at a loss reduction programme. Despite this, however, considerable variations are to be found in the performance of different utilities in the same country, albeit operating in very different types of markets. This is shown in Figure IV for five of the major Colombian power utility groups--the variation of losses between 1971-86 for each of these five systems. For example, the Bogota (EEEB) and CORELCA (Caribbean coastal) companies have had similar movements in losses during the period, despite the vast differences in the spatial coverage of their service areas and their T&D system load densities. The CORELCA area is about 40 times greater in size than that of EEEB and its population density and level of coverage is much lower than EEEB's. In contrast, EPM (Medellin) has succeeded in maintaining its losses relatively constant, though on the high level (about 18%-20%) throughout the period. We need to understand better what causes these differences if we are to design more effective loss reduction efforts. Once more, what appears to be missing is a lack of grasp of how the myriad of factors determining loss levels are interplaying even in a single country context.

5.4 The final aspect of utility performance I should mention concerns forecasts of future loss levels, which become important targets for loss reduction programmes financed by multi-lateral financing agencies. Figure V shows the litany of failures in regard to the EEEB system. These represent joint failures by both the utility and the World Bank, which endorsed these views of the future. Indeed, as losses became worse the forecasts became worse, as a certain desperation appeared to enter the process. Of course, forecasts must be seen strictly in the context for which they were undertaken. This raises a further problem--if losses are not projected to decline fairly quickly then tariffs would have to be raised to compensate for this. This inherently introduces a short-term optimism on the part of both lender and borrower to overcome the immediate hurdle of arriving at an agreement.

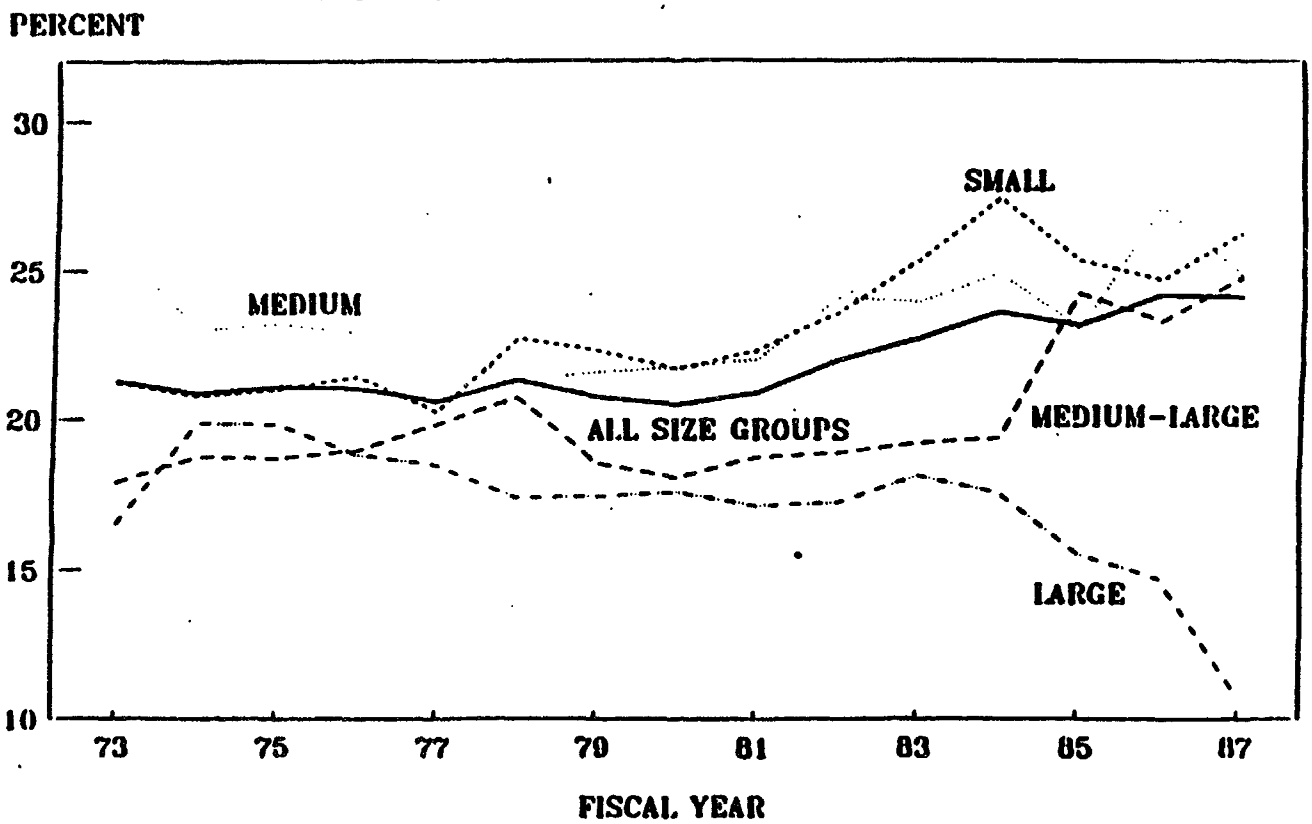
VI. THE CONSUMER CONTEXT OF LOSSES

6.1 The final perspective in viewing losses then becomes that of the consumer. Here there is only one issue I will focus on--that of prices. The rapid increase in power prices in most LDCs during the 1970s in the wake of the oil price shocks also coincided with the period when power losses began their upward spiral. Of course, many other factors were also contributing to increase loss levels, however, that of price must not be neglected. There is likely to be a price threshold below which recourse to power theft is limited, but above which action is taken by the consumer to preserve his consumption at no increased cost. This can manifest itself through re-classification of the rate category of the consumer so that in the new category, to which he does not belong, his effective rate is lower. This is especially prevalent when commercial tariff structures become massively distorted, whereby commercial users are charged 200%-300% above their supply cost, while residences, on average, could be paying 1/2 to 1/3 of their supply cost, and industry about 75% to 100% above its supply cost. This is another area in which more effort at understanding the influence of prices is called for in the context of reducing losses through lowering billing fraud.

6.2 Finally, at the lower end of the scale, i.e. among residences, a better grasp of how prices are affecting decisions of residential consumers about power theft is clearly necessary.

Figure 1

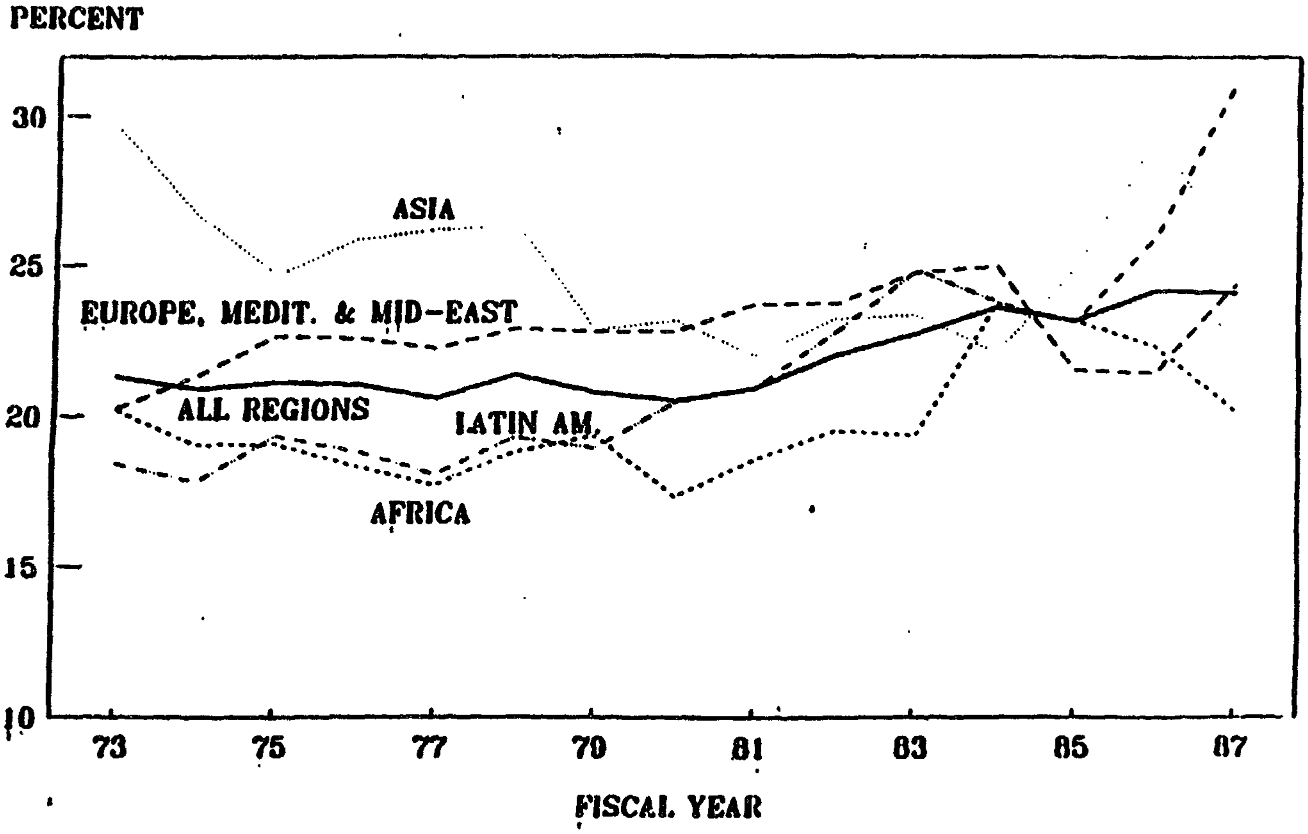
FY73-87 AVERAGE POWER SYSTEM LOSSES BY SYSTEM SIZE GROUPINGS



Source: "Technical and Non-Technical Power Losses in Developing Countries," by G. Schramm, November 1988.

Figure 11

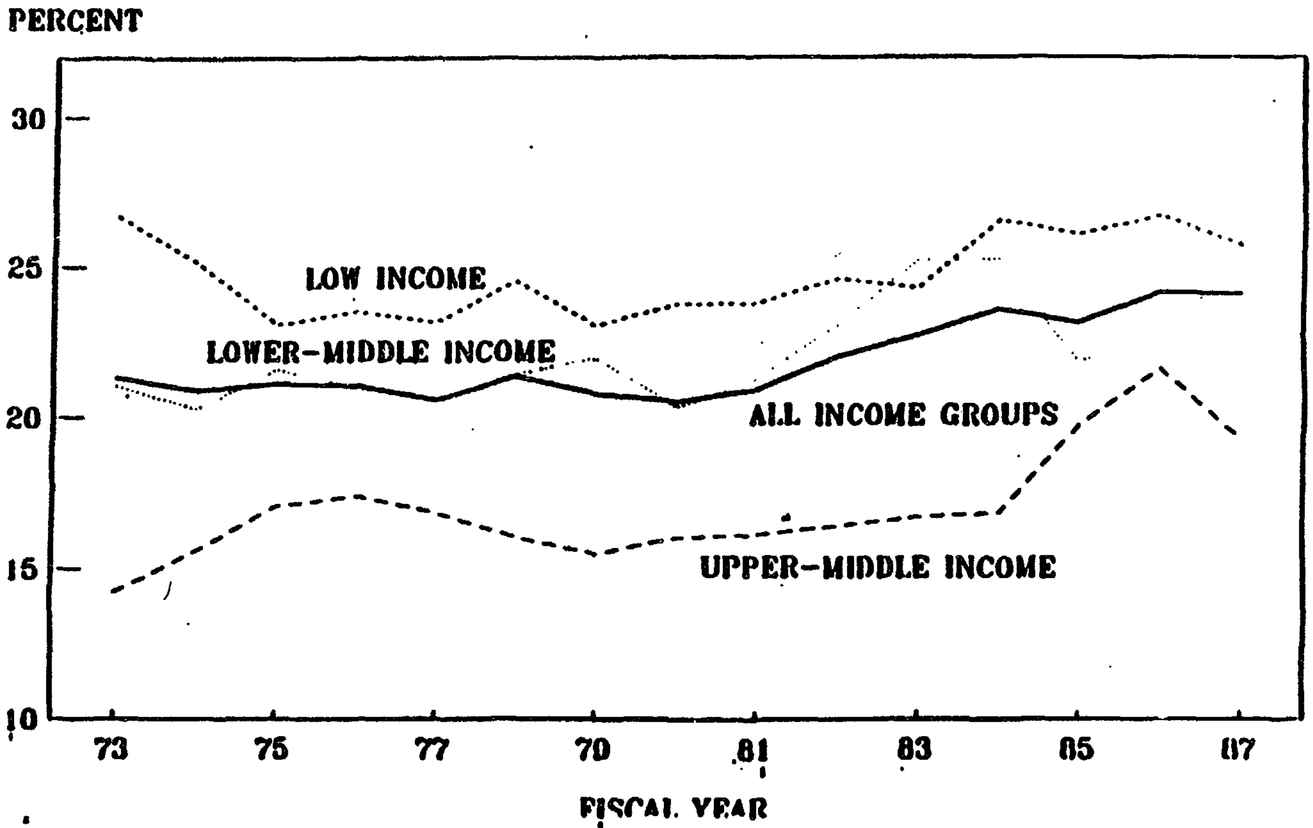
FY73-87 AVERAGE POWER SYSTEM LOSSES BY REGIONAL GROUPINGS



Source: Technical and Non-Technical Power Losses in Developing Countries," by G. Schramm, November 1988.

Figure III

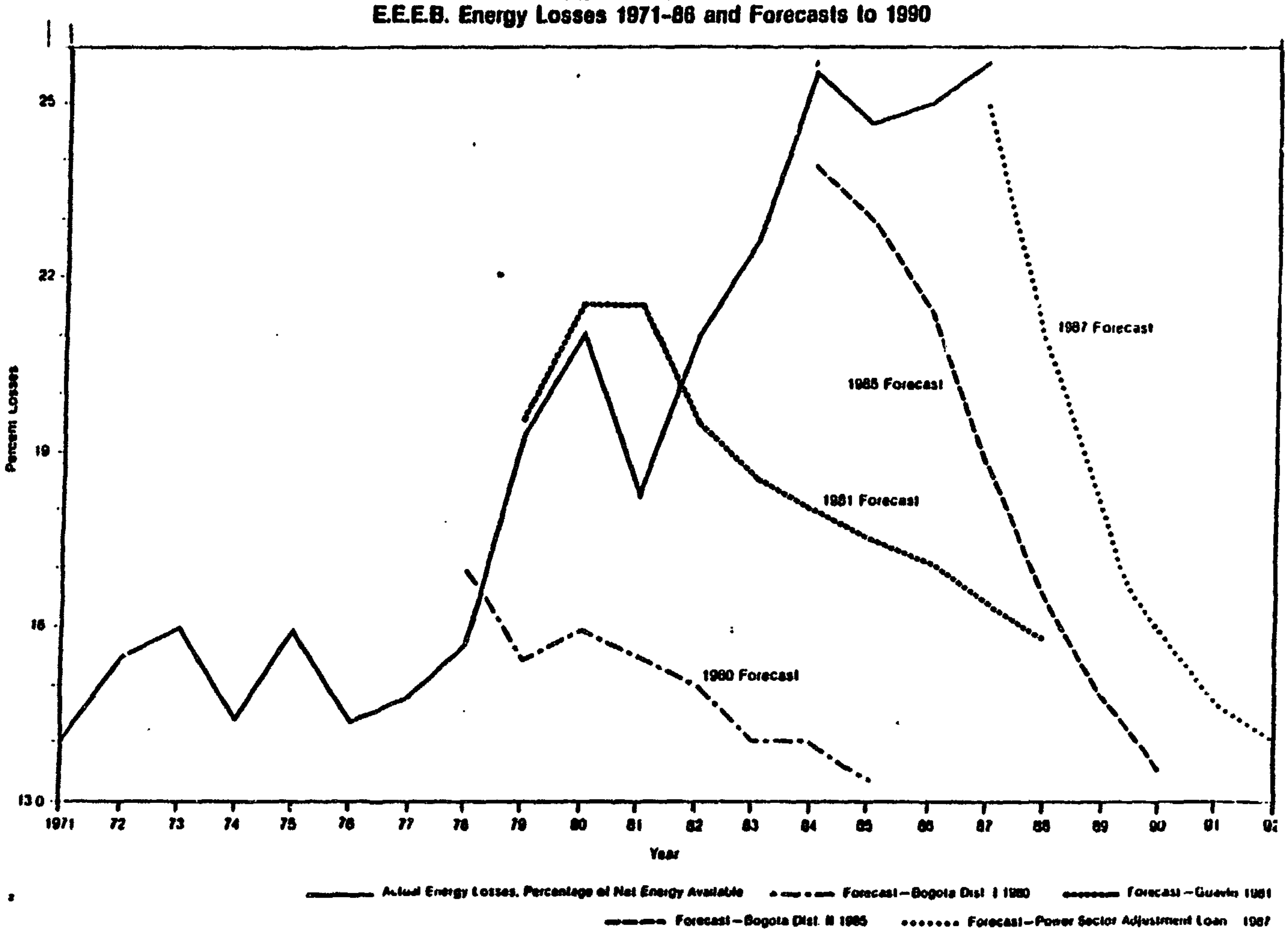
FY73-87 AVERAGE POWER SYSTEM LOSSES BY PER CAPITA INCOME GROUPINGS



Source: "Technical and Non-Technical Power Losses in Developing Countries," by G. Schramm, November 1988

FIGURE IV

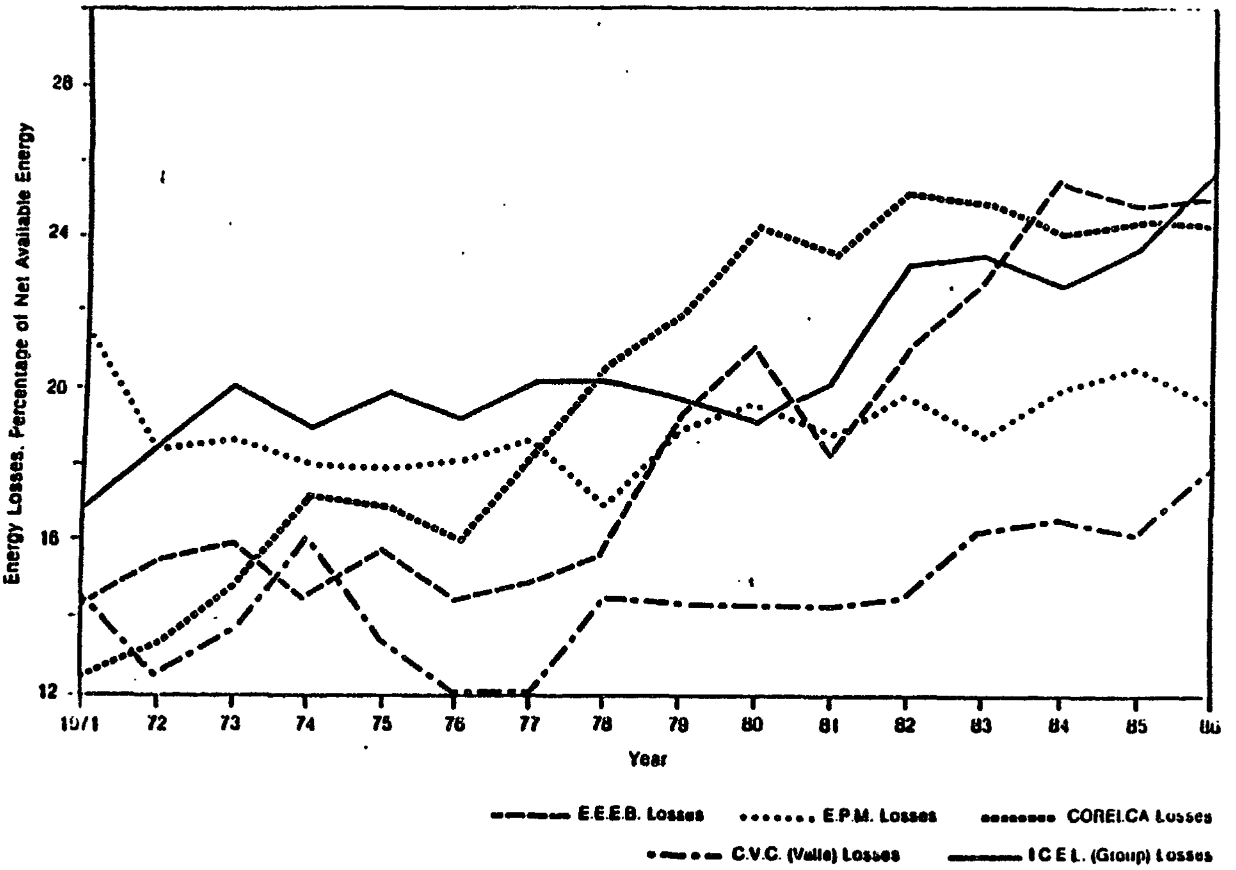
COLOMBIA-POWER SECTOR
E.E.E.B. Energy Losses 1971-86 and Forecasts to 1990



Source: OED Review of Bank Lending to the Colombia Power Sector - 1988.

FIGURE V

COLOMBIA-POWER SECTOR
Energy Losses, Percentage of Net Available Energy



Source: OED Review of Bank Lending to the Colombia Power Sector - 1988.

DETECTING POWER LOSSES
USING
THE OLADE ENERGY BALANCE

Presented by

Ms. June Natasha Budhooram
Head of the Energy Balances Program and
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Abstract

This article presents the philosophy of the Latin American Energy Organization regarding the implications of technical and non-technical losses in the power sector. The analysis englobes the genesis of the energy crisis by presencing a retrospective review of the patterns of energy sector analyses. An important feature of this presentation is the institutional criteria of OLADE for achieving optimal efficiency in the power sector, specifically in what refers to the role of loss reduction programs, and the economic and financial benefits derived thereof.

1. INTRODUCTION

Recent studies undertaken in several countries of the Region have indicated that few countries paid any attention to planning in the energy sector as a whole. This phenomenon was quite understandable in the past because before 1973 oil was a very cheap and abundant energy source. During this period energy planning was restricted to increasing energy supply at any cost, in each of the individual s b-sectors (petroleum, gas, coal, etc.) and with little coordination among them.

This total absence of overall energy planning began to change after the first oil shock, whose severity of repercussions (abrupt deterioration in their terms-of-trade, etc.) led countries to embark on a reduction of oil campaign, where most oil substitution options were determined on the basis of cost/benefits analyses of the individual project alternatives or what is known as micro economic analysis. Another noteworthy feature of energy policy during this period included the greater efficiency of oil use in an attempt to lower oil demand and increase the supply of domestically produced oil.

This led countries to try and identify options for substitution and conservation of energy sources, which meant that the structure of energy demand across the sector had to be analyzed from a highly disaggregated perspective, including types of end-use such as lighting, heating, mechanical force, etc., and by the type of energy supply mix. High priority was therefore assigned to identifying the technically and economically viable alternatives for oil generation. It is worth emphasizing that in many power systems fuel oil and diesel were their main electricity generating source and being such a ready target for substitution options, plans were formulated and projects implemented forthwith. Planning for the energy sector therefore became supply-side focussed and comprising three main elements 1/:

- Analysis of the interactions between each of the energy supply sectors;

- The existence of coherent energy pricing policy both across the supply and demand subsectors;

- Knowledge of the detailed structure of energy demand across the economic sectors.

The importance of these elements and the need to demonstrate the actual nature of their interrelationship led OLADE to develop a methodology for preparing Energy Balances in 1979, a global analytical concept on the basis of which more solid elements could be provided for energy planners and policy makers throughout the Region. Energy Balances have arisen then, as the first stage of a global focus and their aim is to indicate the current situation broken down into primary energy transformation, secondary energy, final and useful consumption. A first contribution of this planning instrument, which already justifies its existence lies in developing a system of consistently reliable information.

The analysis of the energy sector utilizing the energy balances pulls together the whole energy sector and throws light on the interactions at a physical level. However, it does not embrace analysis at the macroeconomic level. In this regard OLADE shares the view of those who affirm that the analysis of the energy sector needs to be undertaken in the broader context of the macroeconomy, especially in those countries where energy investments are considerable or where the sector is an important revenue source for the Government, in terms of foreign-exchange earnings.

The urgency to emphasize this interdependence between the energy sector and the rest of the economy becomes evident if one considers the present economic and financial status of the Region. Prospects on economic development seems to be dim due to the following constraints 2/:

1/ ENERGY AND THE ECONOMY, Trevor Byer. Paper presented at the OLADE's Energy Planning Course for the English speaking Caribbean. Barbados, June 1988.

2/ INTEGRATION OF THE ENERGY SECTOR - BASIC PREMISE FOR THE ECONOMIC TRANSFORMATION IN LATIN AMERICAN AND THE CARIBBEAN. OLADE, Quito 1988.

- The foreign debt, whose nominal value exceeds some US$425 billion;

- Deterioration in the terms-of-trade with values comparable to those of the 1930's depression;

- Protectionism by the industrialized countries;

- Increasing problems of capital mobilization for financing development programs.

The foregoing considerations have generated pressures for creating and adopting new approaches for redifining the techniques required for analyzing energy and the macroeconomy and for strengthening the institutional coordination at all of the corresponding hierarchial levels of the Integrated National Energy Framework. This approach should include 3/

- separation of the energy sector into production, consumption, trade, investment and financial flows;

- sectoral disaggregation on the supply side;

- the ability to assess the budgetary implications of alternative energy policies;

- the recognition of the impact of the reallocation of savings-investment flows between sectors of the economy;

- trade disaggregation and balance-of-payments/foreign debt accounting with energy sector flows transparent;

- an inflationary mechanism which recognizes the impact of energy costs;

- the usual monetary, fiscal and trade/exchange rate policy levers;

- the ability to evaluate the impact on employment of alternative energy strategies; and

- the ability to deal with long term trends as well as short term development.

2. OLADE'S CRITERIA FOR ACHIEVING OPTIMAL EFFICIENCY IN THE POWER SECTOR

One of the fundamental aspects in defining the potential importance of any energy resource, is evaluating the impact that it has on the economy. The availability of adequate energy resources at a reasonable cost is a vital

3/ ENERGY ECONOMICS IN DEVELOPING COUNTRIES : ANALYTICAL FRAMEWORK AND PROBLEMS OF APPLICATION. Mohan Munasinghe. The Energy Journal, Vol. 9 No.1, 1988.

precondition for continued economic progress and the power sector in particular is acknowledged as an engine for economic growth and development.

However, a historical examination of the performance of the power sector demonstrates that it has generally drained financial resources from the rest of the economy; has had a bad financial savings record relative to the sale of its very high capital investments, very often for expanding generation facilities and with little importance given to transmission and distribution facilities. All these factors can be attributed to the easy access that the subsector had to external borrowing.

The power sector has also tended to have higher investment levels than economically justified; significant increases in operating costs and in many developing countries has accounted for the largest share of public sector investment, while generating no foreign exchange as a tradeable energy source.

In this context, there are several constraints that have emerged over the years, and which have had important repercussions for the power subsector and its role in the economy. These include the increasing problems of external capital mobilization, severe changes in the conditions being attached to funding, and the mobilization of domestic savings to sustain the subsector's investment.

Therefore, in an effort to maximize the role of the power subsector in promoting economic development, while at the same time faced with limited investment resources. OLADE, like many other institutions has subscribed to the view that a very pragmatic and effective option available to utilities under their present critical circumstances, is to improve its "EFFICIENCY."

Perhaps, in evaluating these "efficiency" criteria it is useful to recall first principles on the types of efficiency referred to and their definitions. In the power sector one encompasses four basic types of efficiency 4/

- ECONOMIC EFFICIENCY which requires the double condition of productive and allocative efficiency. The first criterion is met by economically optimizing power system planning and operation, while the second is met by setting tariffs at their real economic levels.

- FINANCIAL EFFICIENCY which provides for financial soundness in determining investments and pricing policies, improving revenues, self-financing ratios, etc.

- TECHNICAL EFFICIENCY which implies remedial measures to problems such as: weak planning, inefficient operation and inadequate maintenance, high technical and non-technical losses.

- ADMINISTRATIVE EFFICIENCY which contemplates improvements in the ability to raise prices to meet revenue requirements, poor management, excessive staffing, etc.

4/ A REVIEW OF WORLD BANK LENDING FOR ELECTRIC POWER. Mohan Munasinghe, et. al. Energy Series Paper No.2. The World Bank, Washington D.C. 1988.

3. THE IMPACT OF POWER LOSS REDUCTION ON EFFICIENCY

In determining the impact of improved efficiencies on power loss reduction, it is useful to examine systematically the structure of the energy flow in question. From the matrix of the OLADE energy balance whose format is shown in Fig. 1, one can derive a flow diagram (see Fig. 2) tracing any one energy source from its production to its final and useful consumption.

This flow in simple terms identifies the various nodes within the energy system where losses occur. These are basically found in three specific areas, namely:

- TRANSFORMATION LOSSES (TC): On converting a primary energy source to secondary energy in a given transformation center.
- STORAGE, TRANSPORTATION & DISTRIBUTION LOSSES (STD): Losses incurred during transport, storage, and distribution.
- CONSUMER LOSSES: On converting secondary energy to useful energy forms, e.g. lighting, mechanical force, heat, etc.

Having defined the types of technical losses that may exist in any physical flow of energy, it is convenient, now, to examine this flow for electricity. The purpose of this flow is to illustrate that in the process of delivering electricity to consumers losses are incurred at the generation, transmission, distribution and consumption stages of a power system. (See Fig. 3). Our concern here are the technical and non-technical losses that are incurred in each of the above mentioned stages.

For the purpose of simplifying the analyses to be pursued using the data from the enregy balances for OLADE's Caribbean member countries, a condensed flow of the losses encountered in the electricity subsector is illustrated in Fig. 4.

CONSOLIDATED OLADE ENERGY BALANCE

Unit: 10(3) boe

		Primary Energy										Secondary Energy													
	YEAR:	PETROLEUM	NATURAL GAS	COAL	HYDRO-ENERGY	GEO-ENERG	FISSION FUELS	FIREWOOD	SUGAR CANE PROD.	OTHER ENERGY PROD.	TOTAL PRIMARY ENERGY	LIQUEFIED GAS	GASOLINE & NAPHTHA	KEROSENE & JETFUEL	DIESEL & GAS OIL	HEAVY FUELS	COKE	ELECTRICITY	CHARCOAL	ALCOHOL	GASES	OTHER ENERGY FUELS	NON-ENERGY PROD.	TOTAL SECOND. ENERGY	TOTAL
SUPPLY	PRODUCTION																								
	IMPORTATION																								
	EXPORTATION																								
	VARIATION IN STOCKS				S			U		P		P		L		Y									
	UNUTILIZED																								
	TOTAL SUPPLY																								
TRANSFORMATION	REFINERIES																								
	PUBLIC POWER PLANTS																								
	AUTO-PROD.POWER PLANTS																								
	GAS TREATMENT PLANTS			T		R		A		N		S		F		O		R		M					
	CHARCOAL PLANTS																								
	COKE PLANTS																								
	ALCOHOL DISTILLERIES																								
	OTHER TRANSF. CENTERS																								
	OTHER TRANSFORMATIONS																								
	TOTAL TRANSFORMATION																								
	LOSSES (TRSP,STR,DIST)																								
	ADJUSTMENTS																								
FINAL CONSUMPTION	TRANSPORTATION																								
	INDUSTRIAL																								
	RESIDENTIAL/ COMMERCIAL/PUBLIC		F	I	N	A	L						C	O	N	S	U	M	P	T	I	O	N		
	AGRO/FISHING/MINING																								
	AUTO-CONSUMPTION																								
	OTHERS																								
	FINAL ENERGY CONSUMP.																								
	FINAL NON-ENERGY CONS.																								
	TOTAL FINAL CONSUMP.																								

Figure No. 1

THE OLADE ENERGY BALANCE

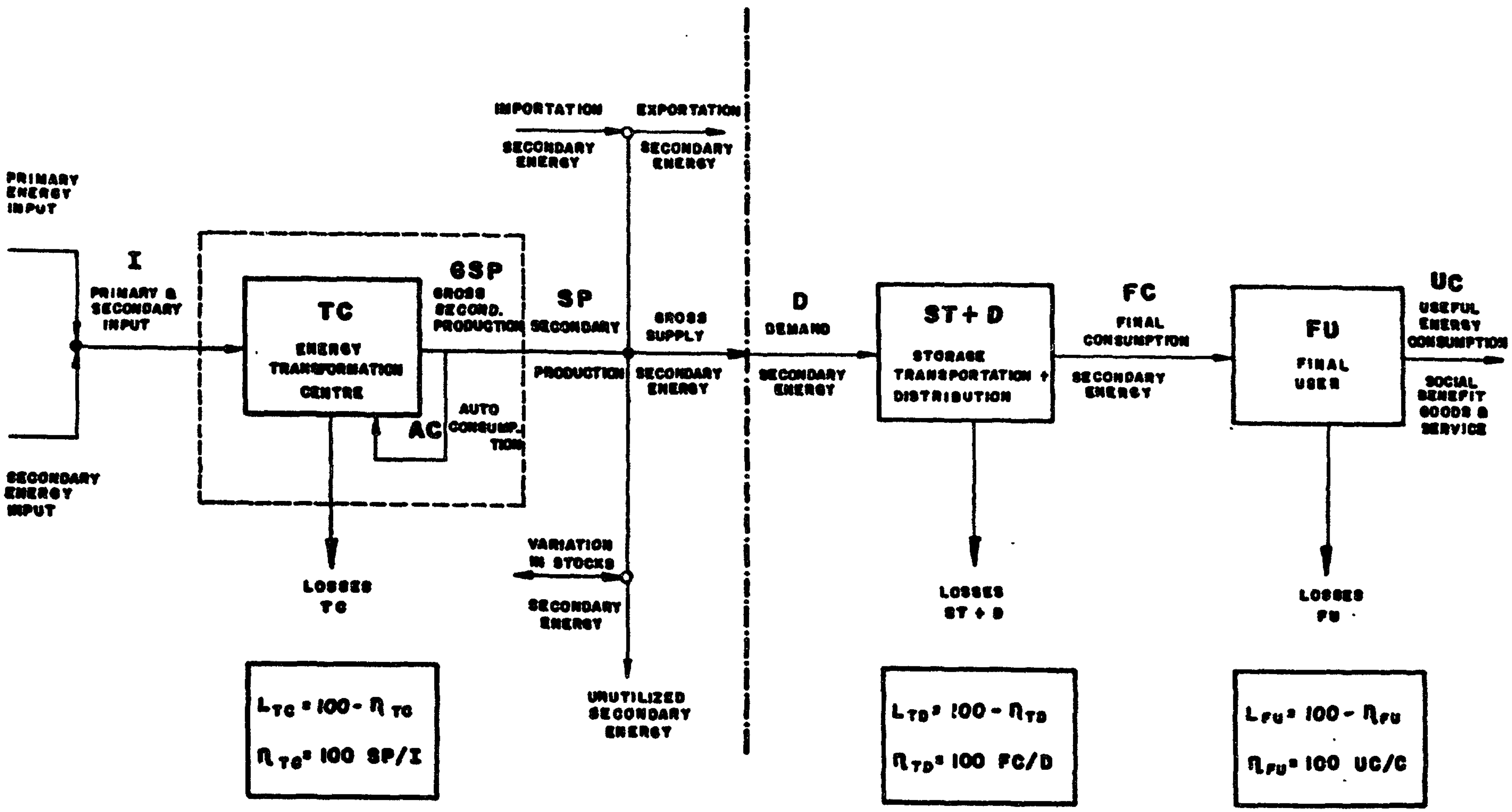


FIG. 2 LOSSES IN ENERGY SUBSECTORS

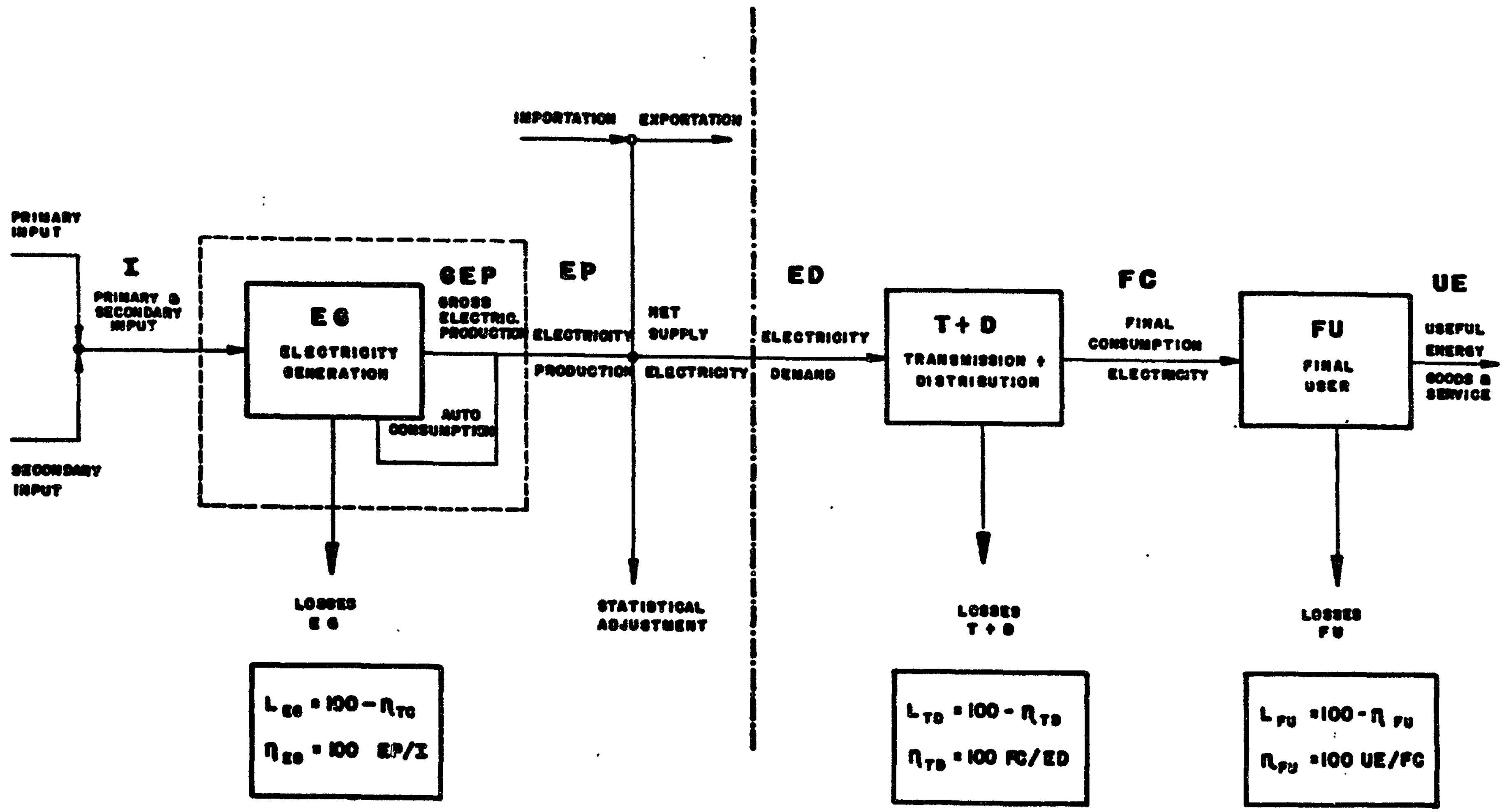


FIG. 3 **LOSSES IN THE ELECTRICITY SUBSECTOR**

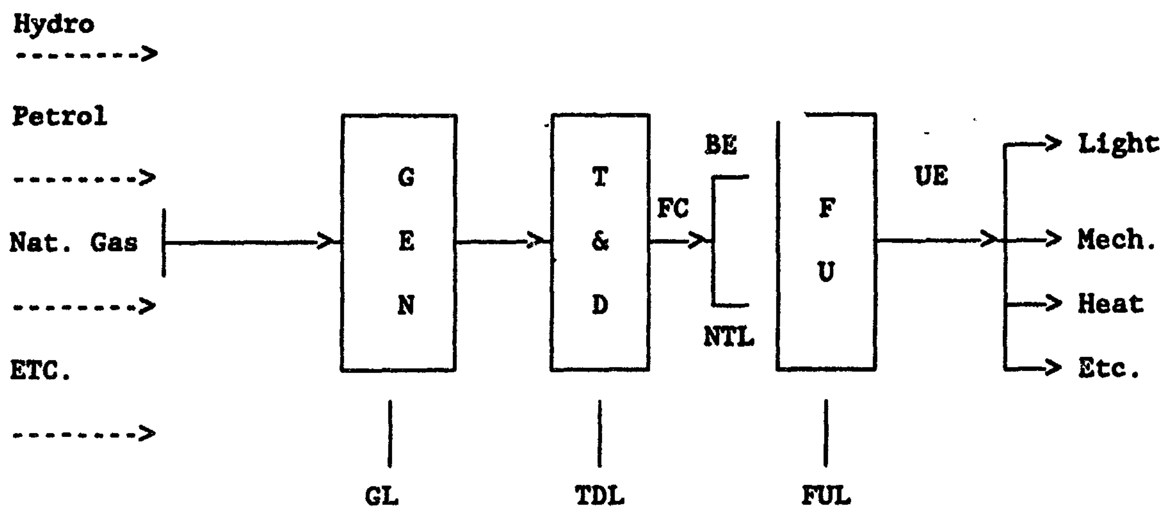


Fig. 4: Simplified Power System Flow

In physical terms we have:

(a) GL = Generation Losses

= 100 - nG (nG is the efficiency of the Generating System. In terms of the transformation from a primary source of energy to electricity).

nG = 100 EP/I

(b) LTD = Transmission & Distribution Losses

= 100 - nTD (nTD is the efficiency of the T&D System)

ntd = 100 FC/EP

(c) FUL = Losses in converting Electricity to energy forms, heat, light, etc.

= 100- nFU (nFU is the efficiency of the converting device: bulb, stove, etc.)

nFU = 100, UC/FC

It is intuitively clear that within the context of power loss reduction one can improve economic efficiency by simply increasing the productive efficiency of the generating system by reducing the technical losses LEG without compromising the quantity of energy (kWh) generated. In fact, to maintain equal levels of electricity generation less fuel will be needed thereby reducing fuel costs in the case of thermal installation.

Parallely, there is an optimization of capital investment as well as improved operation of the generating system by reducing their power losses (MW) which have a direct economic benefit which at a minimum improves the quality of service and possibly permit more load to be served and/or delay the expansion of generation and transmission facilities. It is worth noting here that in high loss systems the outlays required to achieving energy and power savings are generally very much less than the cost of increasing supply capacity.

Within the Transmission and Distribution System, the losses are mainly due to heating in the system. On the average, these losses should technically be below 10% of gross generation while economically optimal loss levels may be as low as 5%. These T&D losses are usually very high and may approach some 20% of gross generation of which three-fourths occur at the distribution level.

It is not surprising then, that these are economic losses and do not only adversely affect the financial state of the utility iteself, but also the national economy. The energy that is lost, or more accurately wasted, due to technical inefficiency, could satisfy additional incremental demand or load. This may generate even more savings of national resources that are assigned to produce electricity.

It is true that the principal reasons for the existence of unacceptably high levels of technical losses in many of our countries are the decline in the financial positions of the power utility and scarcity of foreign exchange resources which has led to reduced investment in system maintenance and rehabilitation in spite of the fact that the prices of copper and aluminium the main components of the distribution hardware system have declined considerably. Today the utilities can put in a lot more of the relatively cheap hardware to reduce the more expensive losses.

On the demand side, at the point of the consumer and the consuming energy devices (electrical machines and appliances), technical losses FUL also occur. In fact, the energy conversion process, from electricity to other forms of useful energy has inherent energy and power losses.

It becomes evidently clear that electricity and power loss occur not only in the power delivery system, but also at the end-use stages. It is convenient here to briefly mention measures to improve end-use losses before discussing the convenience of their optimizaion in the transmission and distribution system.

Energy conservation at the end-use stage may be achieved by two principal methods: (1) improving the technical efficiency of energy using devices and appliances, and/or (2) modifying the shape or characteristics of the load through demand management techniques. More often than not, the public utilities are more concerned with the latter method, which is based on the fact that it is more costly to supply electricity during peak periods (seasonal and daily) rather than off-peak periods. Therefore, changing the shape of the power utility's curve by shifting electricity consumption from peak to off-peak periods will effectively reduce the cost of supply and at the same time, conserve energy.

Until now, discussions have been oriented to technical losses in all the components of a power system. However, besides technical losses there are also non-technical losses associated with the system. These non-technical losses refer to the energy that is consumed and not billed by the utility. The main source of these losses are billing errors, metering errors, unregistered customers and outright theft.

Non-technical losses are primarily financial losses to the utility. Their main impact is evidently on the financial position of the utility itself. The revenues that are lost when electricity is consumed but not paid for by the consumers impose a heavy burden on the financial viability of the utilities both directly and indirectly. Referring to Figure 4, non-technical losses are represented by the energy flow NTL. It is noteworthy, that they are not losses in the technical sense. NTL represents that portion of electricity which is consumed and not billed.

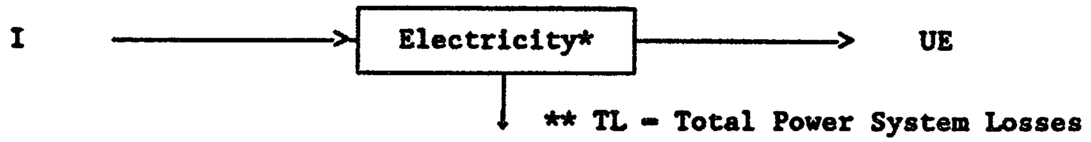
Non-technical losses distort the optimal pattern of electricity consumption, which represents an additional cost to the economy. In utilities where tariffs reflect costs (operating and investment), non fraudulent consumers are charged for the service relatively more than they should and as a consequence, they tend to consume less because the higher cost of those who do not pay for electricity is passed to them through higher tariffs. Conversely, those who do not pay for electricity, tend to consume more than if they had to pay for it. This feature creates a distortion in the economically optimal electricity consumption pattern.

4. THE ECONOMIC AND FINANCIAL BENEFITS FROM LOSS REDUCTION PROGRAMS

It has already been mentioned that a reduction in power and energy losses, but technical and non-technical, may have impacts to the utilities and to the economy at large. Nevertheless, it may be convenient to analyse in more detail, possible direct and indirect benefits and to identify the beneficiaries, as a result of comprehensive loss reduction programs.

From the national economic perspective, it is more convenient to analyse loss reduction programs, taking into account all power system components as an integrated unit, comprising the generation, transmission, distribution and final user sub-systems. This approach, although unusual to most power system analyses, have the advantage of considering the electricity sector as another component of the macroeconomy. In this regard, this component produces an intermediate product which is used for the production of other goods and services in other economic sectors.

Diagramatically, this unit can be represented as follows:



* Includes generation, transmission, distribution and final user sub-systems.

** TL includes GL, TDL and FUL.

Figure 5

In the above Figure 5, TL may be interpreted as total physical losses, either power (MW) or energy (kWh). In monetary terms, these losses may be "financial" or "economic", depending on the conversion factor utilized (market values or shadow prices respectively). Therefore, it becomes evident that a reduction in total power system losses results in economic and financial benefits for the whole economy.

In a similar manner, loss reduction programs in each one of the components of a power system imply economic and financial benefits, accruing to various beneficiaries comprising:

(a) At the macroeconomic level - Ministeries of Finance; Planning; and Economy who can target savings in the development of other sectors i.e. health, education, transport, etc.

(b) At the intermediate level - The Ministry of Energy which can re-allocate these savings for intra-sectoral development. Additionally less fuel requirements will imply less import pressures for OIDC's, while more exports revenues for OEDC's.

(c) At the micro level - Power utilities and Electricity consumers, both benefit because on the one hand, the operational and investment costs, for power delivery may be considerably reduced, while on the other, the consumer by increasing his electricity consumption efficiency receives the same service at a lower cost.

Programs aimed at reducing losses for specific components of a power system, may have different impacts on the various beneficiaries mentioned above.

4.1 Loss Reduction at the Final User Level

Although the loss reduction programs at the final user level may appear to be beyond the scope of power utilities, it is important to highlight the potential benefits derived from such actions.

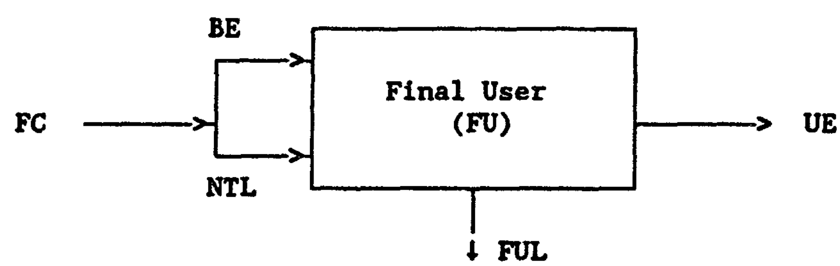


Figure 6

Figure 6 graphically represents the final consumer system, with its corresponding input and output energy flows. A reduction in the final use losses (FUL) is directly proportional to a reduction in the final demand of electricity (FC) entering this sub-system. The resulting effect of this phenomenon are:

(a) The consumer consumes less energy and subsequently lowers his energy bills

(b) The utility, receives less revenues, but at the same time, reduces its operating costs and has the potential to delay investments.

4.2 Loss Reduction at the Power Production and Delivery System

A reduction of technical losses at the power delivery system (generation, transmission, and distribution), shall produce economic and financial savings to the various beneficiaries as follows:

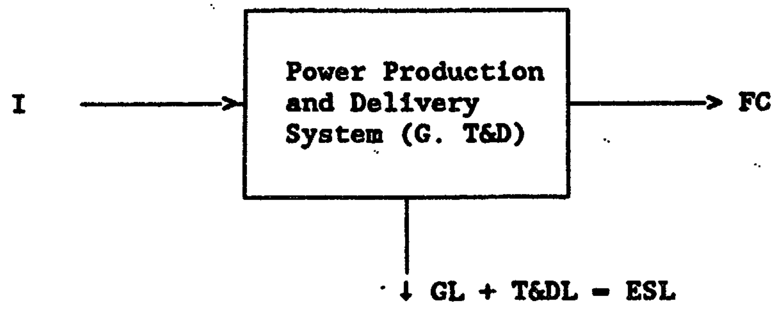


Figure 7

A loss reduction in the electricity production and supply system is guaranteed to:

a. Reduce operating expenses in the system.

b. Delay investments in expanding generation, transmission and distribution facilities.

c. Improve quality of service.

d. Permit more load to be served with existing capacity.

4.3 <u>Non-Technical Loss Reduction</u>

So far the present analysis has been dealing with the benefits derived from reducing technical losses. However, a more careful examination of Figure 4 reveals that there exists other potential areas to further improve efficiency by reducing non-technical losses, which would:

(a) Improve the financial performance of utilities by means of increasing revenues, derived from previously non-billed consumers.

(b) Normalize the electricity consumption pattern, as result of billing previously fraudulent consumers.

5. POTENTIAL ECONOMIC BENEFITS AS A CONSEQUENCE OF AN AGGRESSIVE LOSS REDUCTION PROGRAM IN THE CARIBBEAN

On the basis of information extracted from the OLADE's energy balances for the Caribbean member countries, estimates of the potential benefits derived from an active technical loss reduction program, at the generation level, have been calculated. The purpose of that calculation is to highlight the often neglected potential to improve efficiency at this level and to have an order of magnitude of resulting benefits. To do so, data corresponding to the spectrum of primary energy input into the power plant, auto-consumption and gross generation for the period 1977 to 1986, has been utilized. Table 1 presents a summary of the basic data.

Table 1 : PRINCIPAL ENERGY FLOWS IN THE ELECTRICITY SUBSECTOR IN THE CARIBBEAN (BOE x 10^3)

Year	PRIMARY ENERGY INPUT	LOSS AND AUTO-CONS.	GROSS GENERATION
1977	19731	14660	5071
1978	19883	14609	5274
1979	21341	15738	5603
1980	21020	15220	5800
1981	21267	14916	6351
1982	21214	14781	6433
1983	23285	16523	6762
1984	23789	16842	6947
1985	23324	16075	7249
1986	25836	18267	7569

Source: OLADE Energy Balances for Latin American and the Caribbean 1970-1986.

A diagramatic scheme of energy flows presented in Table 1 may be represented as follows in Figure 8 below:

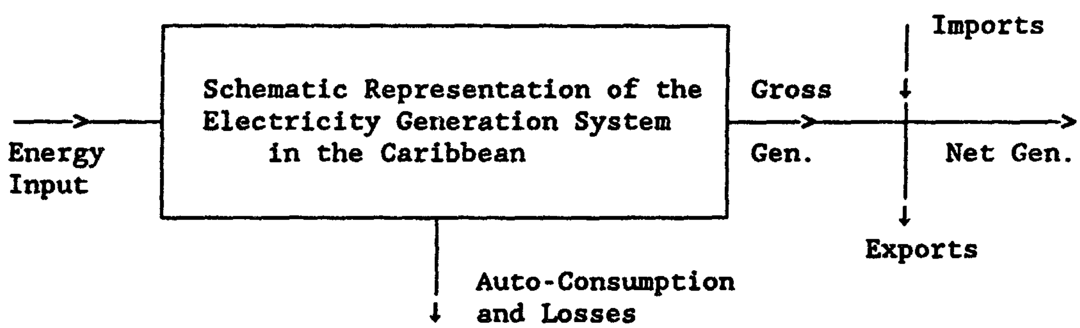


Figure 8

Using the above data, loss figures for the generating system have been calculated (including auto-consumption). No particular trends have been observed and with an erratic behavior they range from 69% in 1985 to 74% in 1977, with an average of 71% for the period in question.

Net generation has been adjusted mathematically, using the least square linear regression method of their natural logarithm. A 6.6% annual growth rate has been obtained with a correlation coefficient of 0.98. A net generation projection has been performed on this basis and two different estimates of primary input energy have been calculated. The first assumes that losses during the next decade will remain in the average value of 71% observed during the period 1977-1986. The second estimate assumes a constant loss value of 66%

implying on average a 5% loss reduction program in the generation systems of the Caribbean. Results are presented in Table 2.

Table 2: PROJECTIONS OF NET GENERATION AND INPUT ENERGY FLOWS FOR DIFFERENT LOSS VALUES IN THE CARIBBEAN

Year	Net Gen. (GWh)	Input Energy Loss = 71% BOE x 10^3	Input Energy Loss = 66% BOE x 10^3
1989	14116	30702	26118
1990	14762	32106	27313
1991	15437	33575	28562
1992	16143	35111	29868
1993	16881	36716	31234
1994	17654	38396	32663
1995	18461	40152	34157
1996	19306	41989	35719
1997	20189	43909	37353
1998	21120	45918	39062

The above results are the basis to evaluate the potential benefits of an eventual loss reduction program. Energy savings have been quantified and evaluated considering US$20 per barrel of fuel. Assuming an average 0.53 load factor, potential power expansion delays have also been estimated, somewhat in the order of 715 MW during the next decade, with their corresponding economic savings evaluated at US$500/kW. Loss reduction costs at the generation level, have been estimated at US$200/kWh delayed. Results are summarized in Table 3.

Table 3: EVALUATION OF POTENTIAL SAVINGS

Year	Energy Savings MM of US$	Power Net Savings MM of US$
1989	92	287
1990	96	300
1991	100	314
1992	105	328
1993	110	343
1994	115	359
1995	120	376
1996	125	392
1997	131	410
1998	137	435
Total	1,131	3,544

6. CONCLUSIONS AND RECOMMENDATIONS

From what has been discussed, the following conclusions may be drawn:

(a) That against the background of the recent critical socio-economic developments in the region there is an urgent need to formulate sub-sectoral electricity policies not only at the sectoral energy level but also within the macroeconomy.

(b) That given the problems that have affected the electricity subsector, there is an urgent need to improve its efficiency in economic, financial, technical and administrative terms. In this regard, loss reduction policies can play a major role by means of reducing power and energy requirements, resulting from improved efficiency at the power system production and delivery stage, as well as at the final consumer level.

(c) The loss reduction programs would appear to be the most beneficial policy option within the short term provided that implementation costs do not exceed the alternative expansion plans. In other words the cost of saving a kW/kWh should be less than the cost to the economy of providing an additional kW/kWh.

(d) That the estimated potential benefits of a loss reduction program for the generating systems of the OLADE's Caribbean member countries merit further consideration. Although it has been reported that, up to three-fourth of losses do occur at the distribution level, it may be worthwhile from a national economic perspective, to further analyse the loss-saving potential at both the generation and final user levels.

SOURCES OF LOSSES

By

Mr. Winston Hay, Industry and Enegy Department, World Bank

Introduction

As electric power is transmitted from the generating station and distributed to the ultimate consumer, the loss of a certain amount of the energy sent out from point of generation cannot be avoided. Previous papers have shown that these losses result in economic costs to the country and financial costs to the utility. In this paper, we will take an overview of the sources and nature of losses and discuss briefly some of the approaches by which they may be reduced.

Figure 1 is a very basic diagrammatic representation of an electric power system. The power is generated in the station (section A) after which the voltage is increased in the step-up transformer (B) to the level at which the transmission lines operate. At the end of, or at points along the transmission line (C) transformers in the substation (D) reduce the voltage to a level appropriate for the primary distribution feeders (E). Distribution transformers (F) along the feeders further reduce the voltage to energize the secondary distribution lines (G) from which the service drops provide the supply to the consumers' meters (H). This diagram incorporates the major components of all systems. Small systems may not have transmission lines, the primary feeders being fed directly from the generating station. Most systems will also have a number of large consumers who obtain their supply directly from the primary feeders or even, perhaps, from the transmission line itself.

Traditionally, such systems have been designed with the major objectives being to:

(a) supply the maximum consumer demand with a constant and acceptable voltage level at all points of supply, even at the end of the distribution feeder;

(b) ensure a reliable supply to the consumer;

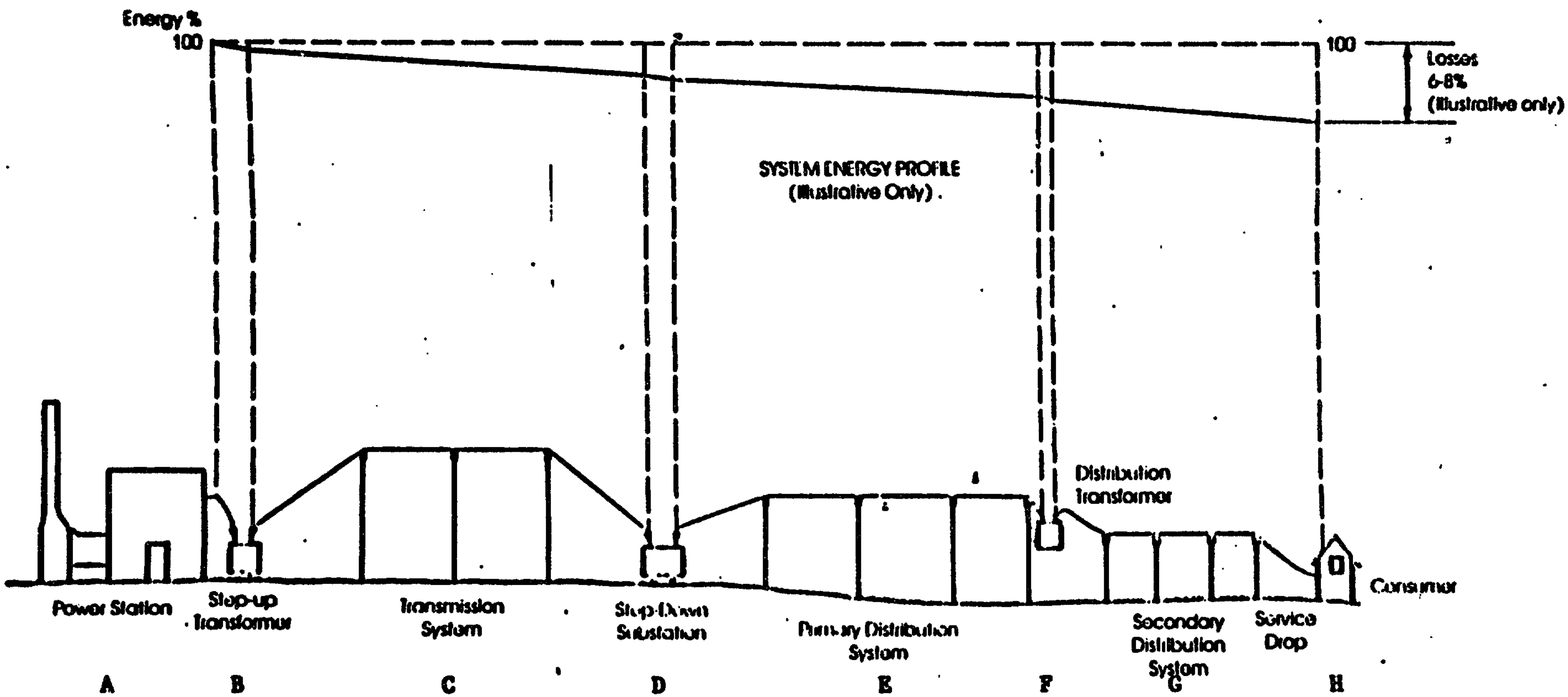
(c) minimize investment and operating costs;

(d) ensure the safety of person and property of consumers and utility employees alike; and

(e) easily accommodate expansion of the system as demand increases.

Losses were seldom a consideration in the planning and implementation of such systems. With time, however, it began to be realized that the least investment cost would seldom represent the least total cost, and that losses represent real costs to the utility and to the country. This realization began to gain wide attention with the increase in the price of energy in the 1970s.

Figure 1: DIAGRAM OF A TYPICAL POWER SYSTEM



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All of the components which form the building blocks of our model system will result in some degree of energy loss. In this paper we will not deal with losses in the generating stations, although these are usually significant and must be included in any thorough evaluation of system losses.

System Energy Losses

We will define system energy losses over any given period of time as the difference between the energy sent out from the power stations and the energy invoice otherwise accounted for during that

System Energy Losses	=	Energy Generated at Power Stations	- Energy Delivered to consumers

Losses are sometimes spoken of as being only the difference between the energy sent out and that for which the utility invoices its consumers. However, not all consumption is invoiced. Very few utilities invoice themselves for their own energy consumption. It is, however, important from the standpoint of good energy accounting that all consumption be metered. In order to know the true extent of losses, the authorized consumption, invoiced or otherwise, must also be known. In discussing power system losses, it is customary to speak of two different classifications--namely "technical" and "non-technical."

Technical Losses

The technical losses are those which inevitably result from the flow of electricity through the components of the system--through transformers, the transmission system, primary and secondary distribution lines, the service drops and even the consumers' meters. In this process, a certain amount of the electricity will be converted into heat. Technical losses can be further subdivided into "load losses" which result from the resistance of the circuits in which the current flows, and "no-load" losses which occur primarily in inductive equipment such as meters, motors, and transformers, and which are independent of consumer demand. They continue even when there is no such demand. From the standpoint of electric power systems no-load losses normally need to be considered only for transformers, since metering losses are very low and there are not many motors as components of the utility's power system outside of the customer load. The no-load losses of a transformer comprise the eddy current, hysterisis and dielectric losses, as well as the resistance losses resulting from the exciting current in the primary winding.

The technical losses on electric power systems are predominantly resistance or the so-called "I^2R" losses. These losses may, therefore, be lowered by reducing the current, the circuit resistance or both. However, since the losses vary with the square of the current but directly with the resistance, loss reduction measures which reduce the current are proportionately more effective than those which reduce the resistance. For any given system demand the current may be reduced by increasing the operating voltage or by improving the power factor. The circuit resistance may be reduced primarily by increasing the size of conductors, changing the conductor material and/or replacing existing transformers with others of lower load losses. The ways in which these loss reduction measures may be accomplished are dealt with in greater detail in subsequent presentations. Discussions of ways and means by which losses may be reduced must necessarily consider details of the sources of losses, and it may be useful to take a somewhat superficial look at these sources at this point.

Step-Up Transformer

Returning to Figure 1, and tracing the flow of current from the generating station to the consumer, the first major system component will be the step-up transformer. The losses in this transformer will consist of the no-load portion which is constant as long as the transformer remains energized, and the load portion which will vary with the square of the current, and therefore with the square of the load if a constant power factor is assumed. Once the transformer has been purchased and installed, there is little that can be done to reduce its losses, short of replacing the transformer entirely. This lack of flexibility in controlling transformer losses makes it important to properly evaluate the losses before the transformer is purchased. The no-load losses are sometimes overlooked in these evaluations, but recognition of the fact that they continue effectively for 8,760 hours/year will indicate that they could possibly exceed the load losses. In any case, they will be significant.

Transmission System

The current next flows through the transmission system. Transmission losses will vary with the square of the current and directly as the resistance of the line. The magnitude of the current will be determined by the total load (consumer demand plus losses), the operating voltage, and the power factor. Line resistance will be a function of conductor material, conductor cross section, and the length of the line.

Losses can therefore be reduced by increasing the operating voltage, improving the power factor, changing the conductor to one made of material of lower resistivity, increasing the conductor size, and/or reducing the length of the line. Of these alternatives, increasing the operating voltage and increasing the size of the conductors are the approaches most often used on transmission lines. Running an additional parallel line is effectively the same as increasing the size of the conductor. It is also possible to reduce the resistance by changing the material used for the conductor, but there are other factors which influence the choice of conductor material and these are often more important than variations in resistivity. It is interesting to note in this respect, however, that all-steel conductors were once fairly widely used but are now seldom, if ever, encountered on new power lines. This is because of the relatively high resistance of steel in comparison to its weight.

The options for shortening the length of a transmission line are generally restricted but ought not to be overlooked.

Power factor is best corrected at the source of the demand for reactive power. Any power factor correction on a transmission line should therefore be to supply the reactive power demands of the line itself. Transmission lines have both capacitive and inductive effects but these tend to be small except on long, high-voltage lines. They also tend to offset each other, the dominant effect depending on the length of the line, the voltage, and the load. Power factor correction on transmission lines is therefore normally undertaken only on long, high-voltage lines. It needs to be carefully implemented to maintain slightly lagging power factor at the source since leading power factor will result in negative generator voltage regulation.

The transmission voltage is reduced to that of the primary distribution system in the substation transformer. Loss considerations for this transformer are the same as for the generator step-up transformer.

Primary Distribution System

Similarly, the sources of losses, and consequently the possibilities of loss reduction, on the primary distribution system are essentially identical to those of the transmission system. The emphasis may, however, be different. Line reactance is of even lower significance for losses. Opportunities for shortening the lengths of primary distribution lines are generally encountered more often than is the case for transmission lines. This is because of the possibilities of switching loads from one line to another in close proximity, and extending additional feeders from the same or another substation. Power factor correction is also most often installed on the primary lines. Although the reactive demand may be predominantly on the secondary systems, it is generally more economic to install the capacitors on the primary system. The capacitance of a given capacitor varies with the square of the applied voltage. A capacitor of a fixed size is therefore more effective on the higher voltage of the primary system than on the secondary system.

Primary lines are sometimes run as two phase or single phase extensions. Increasing the number of phases in such instances will lower the losses by reducing the current per phase.

Distribution Transformers

The distribution transformer links the primary and secondary distribution systems. Again, the no-load and load loss considerations apply. Often the ratio of average load to peak load is lower for distribution transformers than it is for substation or generator transformers, so that the no-load losses assume even greater significance for overall losses. It is dangerous to generalize, however, and the economics of transformer loss reduction should be applied individually, or in groups which are known to comprise units of very similar load characteristics.

Secondary Distribution

Loss reduction on secondary distribution lines is subject to the same considerations as primary lines. The possibilities of reducing losses by shortening the lines are even greater, as it now often becomes simply a question of installing distribution transformers at more frequent intervals. The other options of increasing conductor size or the number of feeders remain applicable. If power factor correction is undertaken on secondary lines it will be especially effective at the points of supply to large consumers with high reactive demands. Lines of less than three phases are more often encountered, so that there will probably be greater scope for reducing losses by increasing the number of phases. On the other hand, the supply voltage is normally standardized, effectively ruling out voltage increase as an approach to loss reduction.

The final link in the supply chain is the service drop from the secondary line to the consumer's meter. From the standpoint of losses, the important consideration in this instance is to ensure that the line is adequately sized. However, it is false economy to attempt to save investment costs by carefully sizing the service line to each consumer's existing demand. That demand will almost always increase with time, but checks on adequate service line sizing to existing consumers are very seldom made before problems develop.

Inductive Reactance

The energy losses in a transmission or distribution line are determined by the resistance of the conductors. However, the reactance of these lines is also important because of its effect on voltage drop. The reactance of a line often results in a greater voltage drop than that produced by its resistance. Although the reactive voltage drop does not result in energy loss it can have a critical effect on the quality of supply to power consumers and also on the quantity of energy sold. The latter will, of course, have an effect on the financial returns on the utility's investments.

The reactance of lines can be easily calculated. In general reactance varies inversely with the radius of the conductor and directly with the conductor spacing. In both instances the variation is a logarithmic function.

OTHER SOURCES OF LOSSES

Two additional sources of technical losses are frequently mentioned. They are high-resistance joints and vegetation in contact with the lines. In all probability, these do not contribute significantly to overall losses. Both are far more likely to affect reliability of supply than losses. High resistance joints are especially a problem with aluminum conductors because the oxide on the surface of the metal is not a good conductor of electricity. The energy lost in the joints is transformed into heat, and the joint consequently gets hot. If a lot of energy is being dissipated, the metal will melt and the joint will become open-circuited. Unless burning of conductor joints is a frequent occurrence, the losses at these joints are probably negligible.

Similarly, vegetation in contact with uninsulated power lines will burn away if they conduct significant amounts of energy. This is especially noticeable on lines which operate at or above 12,000 volts. Nevertheless, good housekeeping demands that conductor joints provide good contact and that power lines be kept free of vegetation.

In concluding these discussions of technical losses there is a point not yet focussed on but which ought not to be overlooked. It is that losses increase the power demand on the system and that this increase in demand is itself the cause of further losses. The losses at one end of a secondary distribution line will be the cause of an increase in the power generated and in the total current flow through, and therefore in the losses in the various transformers, the transmission and primary distribution lines, the secondary distribution system upstream of the end point. Technical losses, therefore, are themselves the cause of further losses.

Non-Technical Losses

Non-technical losses represent energy consumed for which the utility does not receive revenues. The primary sources of non-technical losses are:

(a) Unmetered supplies. These may be due to direct connections made by consumers who wish to enjoy the benefits of electricity without having to pay the cost. It can also result from direct connections made by the utility because of meter shortages, and which were never regularized. Customers can be removed from the accounts records while their premises are still connected to electricity.

In some countries supplies to government offices, public light, and certain other public facilities are not metered or even reliably estimated.

(b) Defective metering. This may be the result of the meter having been tampered with in an attempt at fraud, or the meter may be incorrectly connected, have been installed with defects or have developed defects after installation.

(c) Meter reading errors. The meters are either incorrectly read or not read at all.

(d) Billing deficiencies. Errors may be made in the calculation of the bills, bills may not be prepared for certain consumers because meter readings were not received or for a variety of other reasons, bills may be prepared but not delivered, etc.

Non technical losses have a direct impact on the finances of the utility affected. With the increase in energy prices in the 1970s, a large number of utilities experienced an increase in losses as more and more consumers attempted to avoid having to pay the increased costs of electricity supply. Many utilities, particularly in developing countries, have not been able to implement the controls which would reduce the theft of power to a minimum.

If total system losses exceed about 15% of net generation, it is almost certain that non-technical losses constitute a significant contributor to the total. This is not to imply that these losses are insignificant if the total percentage is lower than 15. It is best to make a thorough calculation of the technical losses and so develop a realistic estimate of the extent of the non-technical.

Target Loss Levels

Reduction of losses, especially technical losses, will require investment of capital. For any given system, there is therefore an economic level of losses at which the benefits to be obtained from additional investments would not be recovered in the benefits of further reduction in losses. This optimum loss level is, however, dependent on a number of factors which, in combination, are peculiar to each utility. No specific target level for technical losses can be given as being applicable to all utilities. In general, however, it can be confidently said that if the technical losses exceed 10% of net generation, there is room for economic reduction of losses.

The case of non-technical losses is simpler. There the target level ought to be zero. Unlike technical losses, non-technical losses are not inevitable, and very often dramatic improvements can be achieved in this area without significant investment of capital. Reduction of non-technical losses is primarily a matter of good management. There are many utilities, including several in developing countries, which have levels of non-technical losses which are effectively zero.

Conclusions

Per capita electricity usage is one of the measures of economic development and quality of life. Losses, however, are a useless waste of resources. If losses were totally eliminated, the consumer would still be able to have his electricity demand satisfied but the resources required to satisfy that demand would have been appreciably reduced. Technical losses cannot be completely eliminated but they can be controlled. Non-technical losses can be effectively reduced to zero. The extent to which a utility can economically reduce losses is therefore one of the standards which may be used to gauge the efficiency of its operations. In particular, of its management.

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IMPORTANT PARAMETERS IN LOSS CALCULATIONS

By

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Introduction

Any program to reduce technical losses will involve the investment of money. Typically the incremental effect of each dollar invested decreases as the losses decline. For each system or subsystem, there is therefore an optimum level of losses at which the costs of further reduction in the level of losses will exceed the benefits which result. There is, however, no specific loss level which is optimum for all systems. That optimum is influenced by a number of characteristics which vary widely from system to system. Some of these characteristics, such as the incremental costs of demand and energy losses, have been dealt with in a previous paper. Energy losses may cost less, for instance, on a system supplied from indigenous hydro plants than on one in which the power is generated by steam plants fired with imported oil. The economics of loss reduction will also be influenced by factors such as the size of the system, consumer density, average consumption, etc. Especially important is the pattern of load demand with time, as characterized by a number of system parameters. We will concentrate on some of these in this paper.

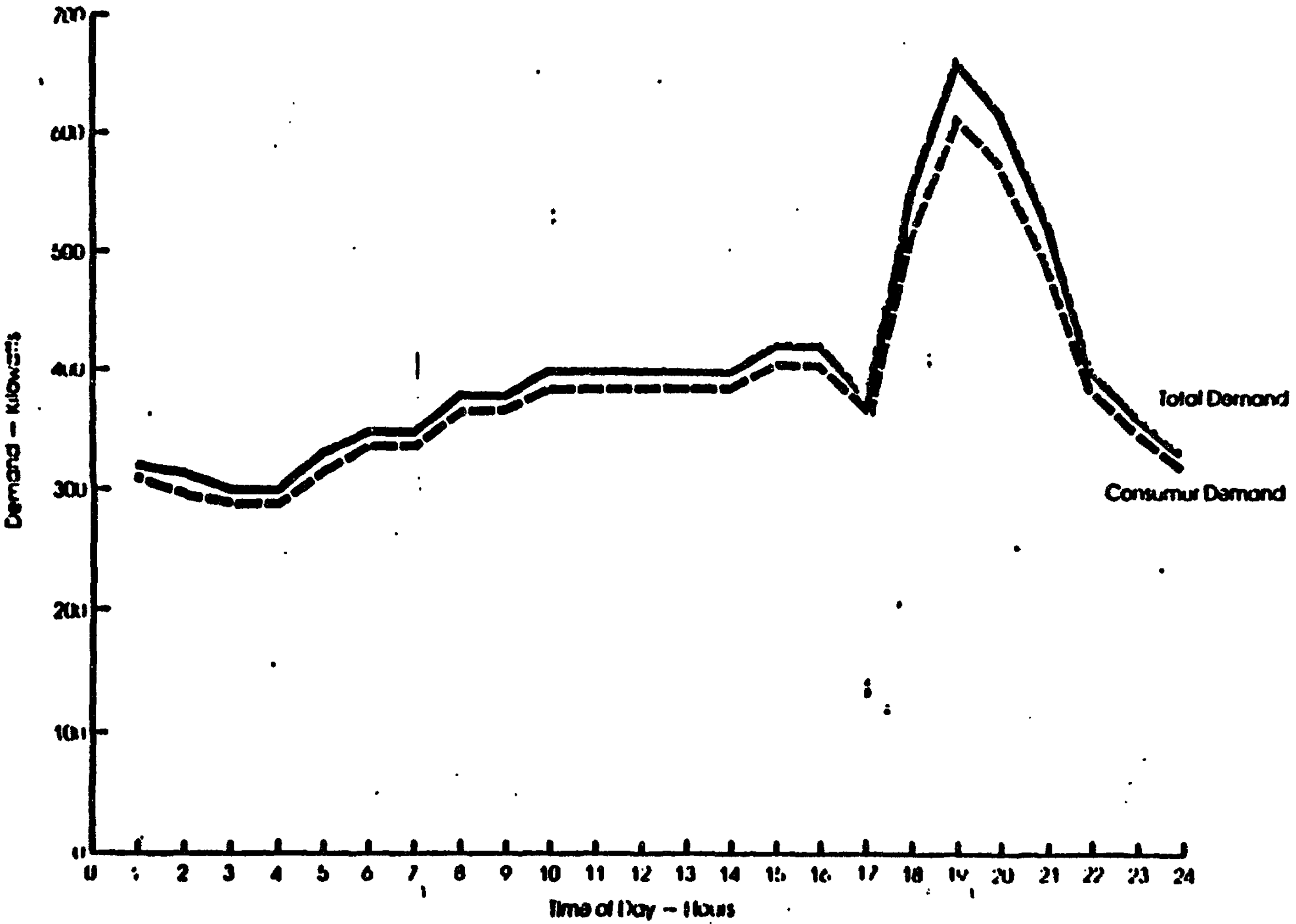
Table 1 below shows the hourly demands on a hypothetical feeder for a given day. The demand profile is graphically presented in Figure 1.

Table 1

Hour	Load (kW)	Hour	Load (kW)
1	320	13	400
2	310	14	400
3	300	15	420
4	300	16	420
5	330	17	380
6	350	18	550
7	350	19	660
8	380	20	620
9	380	21	520
10	400	22	400
11	400	23	360
12	400	24	330

The shape of the curve in Figure 1 is characteristic of feeders with a preponderance of residential consumers. The demand is at its minimum in the early morning hours, increases slightly during the business hours and experiences a sharp increase with the onset of darkness. The absolute peak occurs between 7:00 p.m. and 8:00 p.m., and the demand then declines relatively gradually to the early morning.

Figure 1
FEEDER NO. 1 HOURLY DEMANDS
TOTAL DEMAND AND CONSUMER DEMAND (RESIDENTIAL)



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The nature of the consumer demand determines the shape of the time/demand curve. Figure 2 represents the weekday demand profile of another feeder on the same hypothetical system. This feeder is one on which the demand of commercial consumers is primarily responsible for the shape of the profile. The demand is also at its minimum during the early morning hours, but the steep increase occurs at the beginning of business hours. The load remains relatively constant until the businesses begin to close. There is a slight increase in demand as darkness falls and lights are turned on, but the nighttime load is always well below the average during the business hours. The peak demands continue for longer periods than was the case with the former period so that the average demand will be higher.

Peak Demand

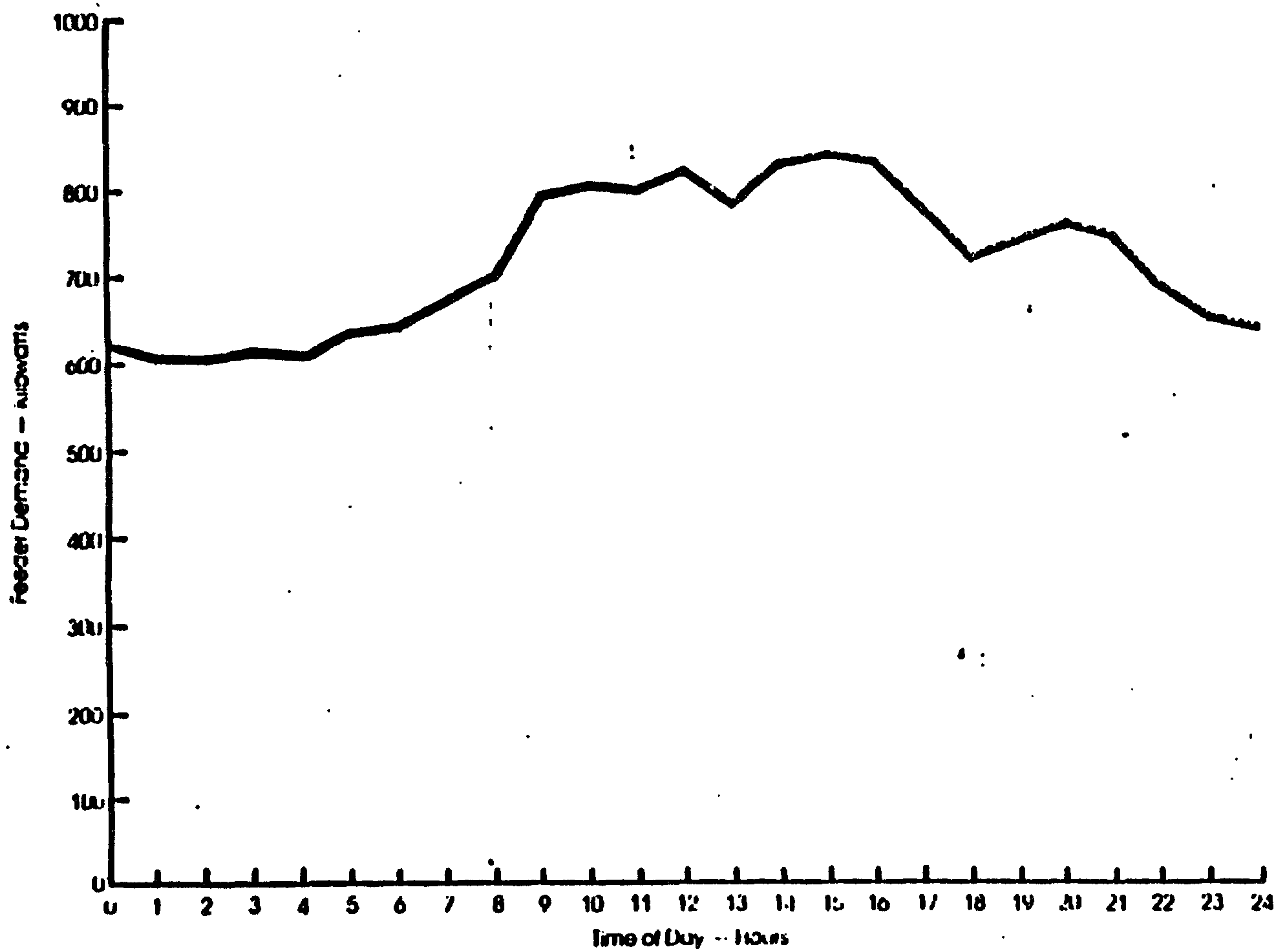
The data points used to plot Figures 1 and 2 are such as would be taken from a logsheet. Each value will be the instantaneous reading at the moment the operator recorded them. These are hourly readings, and the peak, or maximum demand experienced during the day being reviewed, is shown as occurring at some specific hour, 8:00 p.m. in the case of Figure 1 and 1:00 p.m. for Figure 2. In practice, the demand could have varied quite appreciably at periods in between readings and the actual feeder peaks could have been experienced at some time other than that at which the readings were made. The true peak demands may have been experienced for 15 minutes, 5 minutes or even less. Similarly, it is quite possible that during the period of lowest demand the true minimum load may have been lower than that shown on the graphs. The two effects may tend to cancel each other, but the peak demand of a feeder or of an entire system is more important because it determines the capacity which will be required of the feeder or system. It must therefore always be kept in mind that the true instantaneous peak demand may be higher than that recorded at hourly intervals. The actual figure may be more frequently at times at or close to that or peak demand, or by installing continuous recording devices.

Load Factor

Load factor is the ratio of average load to maximum demand. Load factors are usually expressed as percentages and may be calculated for any given period of time but are normally for a day, a week, a month or a year. For loss reduction purposes the annual load factor is the most useful as a year represents a full cycle of seasons and is also the interval most often used in planning studies.

The average load may be defined as the continuous and unchanging load which would draw the same amount of energy over the given period of time as the actual load. It is calculated by dividing the actual energy transferred during the given period of time by the period of time. Care must be taken that the units employed are consistent. For instance if the energy is stated in kilowatt hours, then the unit of time should be hours and the average load will be obtained in kilowatts.

Figure 2
FEEDER NO. 2 HOURLY DEMANDS
(COMMERCIAL)



If we return to the load readings of Table 1 and assume that each of the hourly demands shown in Table 1 did in fact continue for a full hour, then the energy transferred by the feeder on that day would have been the sum of the individual hourly loads, or 9,680 kWh. The average load would be 403 kW. The peak demand of the day was 660 kW at 7:00 p.m. The load factor, or ratio of average of average load to peak demand for this feeder on the day shown would be:

403/660 x 100 = 61% or
9,680/24/660 x 100 = 61%.

It is to be noted that the only data required for the calculation of the load factor for any system or piece of equipment are:

(a) the period of time over which the load factor is calculated;

(b) the maximum demand during that period; and

(c) the energy transferred during that period.

It is therefore not necessary to record hourly or any other regular demands. A kilowatt hour integrator and a maximum demand meter will together provide the energy data required.

In the example above the period of time over which the load factor was calculated is one day. As was mentioned previously, any time period may be used as the basis of load factor calculations, and care must be taken to ensure that units are consistently employed.

Losses

The load on any system will be determined primarily by the consumer demand. The current flow to meet this demand will result in losses. Load losses are proportional to the square of the current flowing in the system and can therefore be taken as being directly related to the squares of the demand in kilowatts, assuming constant voltage and power factor. On this basis, if feeder or system load losses are known for any given demand, they can be calculated for other demand levels. System losses are normally calculated initially for the annual peak demand.

For the feeder whose demands are shown in Table 1, the losses at peak demand (660 kW) were calculated to be 48 kW. The consumer demand at peak is then 610 kW. Table 2 below shows the losses and consumer demands for each of the hourly readings recorded in Table 1.

Table 2: FEEDER DEMANDS, LOSSES, AND CONSUMER DEMANDS

Hour	Feeder Load	Loss	Consumer Demand	Hour	Feeder Load	Loss	Consumer Demand
	(kW)	(kW)	(kW)	)kW)	(kW)	(kW)	
1	320	11	309	13	400	18	382
2	310	11	299	14	400	18	382
3	300	10	290	15	420	19	401
4	300	10	290	16	420	19	401
5	330	12	318	17	380	16	364
6	350	13	337	18	550	33	517
7	350	13	337	19	660	48	612
8	380	16	364	20	620	42	578
9	380	16	364	21	520	30	490
10	400	18	382	22	400	18	382
11	400	18	382	23	350	14	346
12	400	18	382	24	330	12	318

Figure 1 graphically represents not only the total feeder demand, but also the consumer demand over the 24 hour cycle, the difference between the two demands being losses. The increasing effect of losses on total demand as the consumer demand also increases will be evident from the curves in Figure 1.

Duration Curves

A duration curve relates the variation of a given parameter to time over a specified period. For any given value of the parameter, it is either equalled or exceeded. Duration curves for demands and losses are useful to illustrate the chronological patterns of these variables. Table 3 assembles the data required to plot the duration curves for total demand and losses for the hypothetical feeder of Table 1. As losses are proportional to the square of the demand, the latter may be used to establish ratios for losses. In this way, knowing what the demand profiles are, we can develop a duration curve for losses without knowing what the actual loss values are.

Table 3: DEMAND AND LOSS DURATION

Demand a/	Frequency b/	Eg/Ex c/	Dur d/	Eq/Ex e/	Pk. Dm f/	Demand Squared g/	Sq. of Pk. Dm h/
(kW)			(%)	(%)	(kW^2	(%)	(%)
660	1	1	4	4	100	435,550	100
610	1	2	4	8	94	384,400	88
550	1	3	4	13	83	302,500	69
520	1	4	4	17	79	270,400	62
420	2	5	6	25	64	176,400	40
400	6	12	25	50	61	160,000	37
380	3	15	12	63	58	144,400	33
360	1	16	4	67	55	129,600	30
350	2	18	8	83	50	108,900	25
330	2	20	8	83	50	108,900	25
320	1	21	4	88	48	102,400	24
310	1	22	4	92	47	96,100	22
300	2	24	8	100	45	90,000	21

a/ Column 1 lists the various hourly demand readings recorded, arranged in descending order of magnitude.

b/ Column 2 indicates the number of times that the specific kilowatt demand was recorded during the 24 hour period.

c/ Column 3 shows the number of times that the specific demand was equalled or exceeded.

d/ Column 4 indicates the period over which the demand was experienced, expressed as a percentage of the total period (24 hours).

e/ Column 5 indicates the period during which the demand was equalled or exceeded, again shown as a percentage of the total period. The values in this column represent summations of the percentage durations calculated in Column 4 for the specific and higher demand levels.

f/ Column 6 shows the recorded demand as a percentage of peak demand.

g/ Column 7 lists the squares of the instantaneous demands. The losses will be proportional to these values.

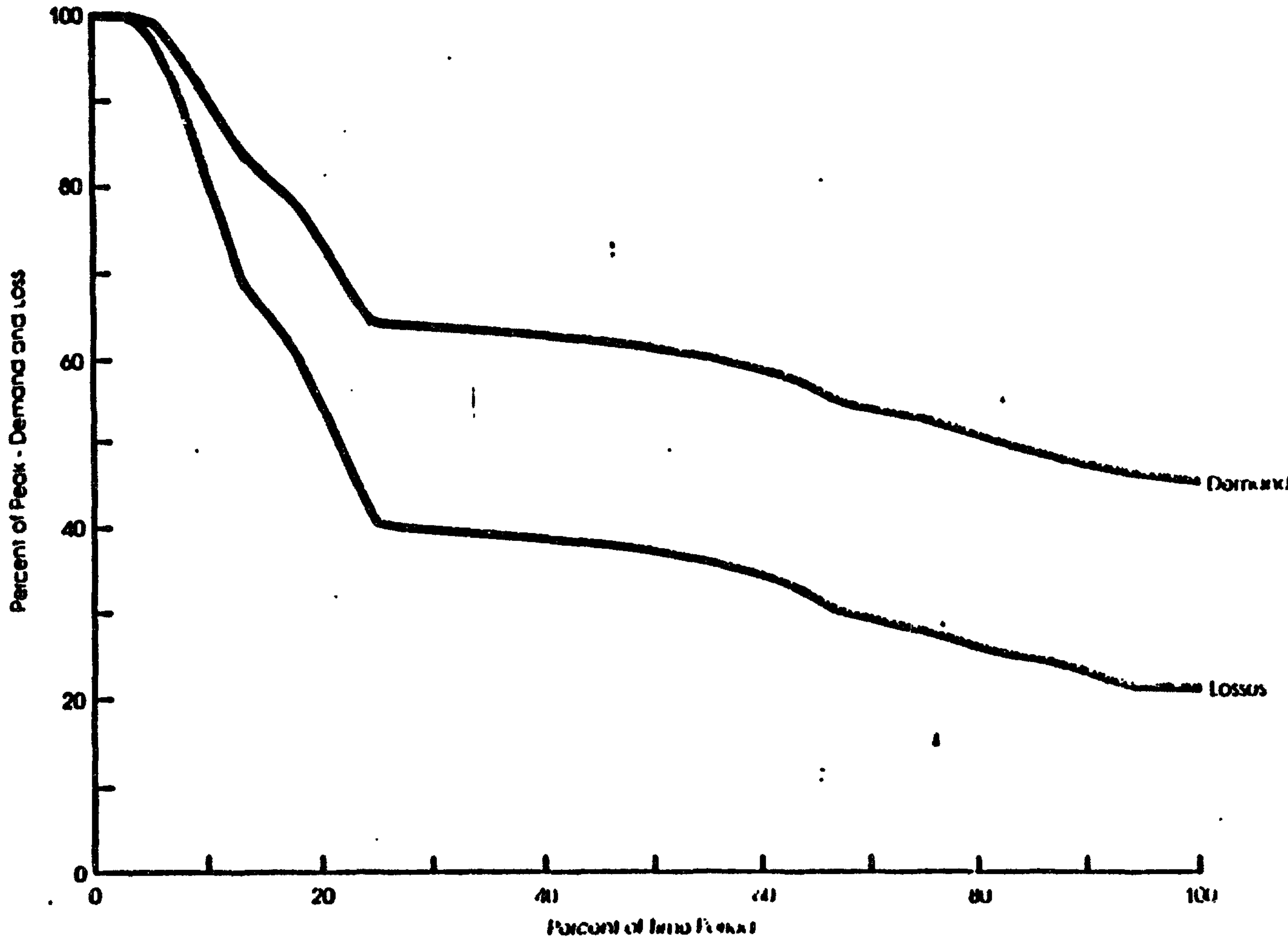
h/ Column 8 shows the ratio of the square of the instantaneous demand, expressed as a percentage. This percentage will also be the ratio of the losses at that demand level to those at peak demand.

Table 3 is based on the assumption that each demand reading recorded was maintained for a full hour. All values have been rounded off to the nearest whole number.

The data in Table 3 has been used to plot the Demand and Load Loss Duration curves shown in Figure 3.

Duration curves can be plotted in units other than the percentages used in Figure 3. For instance, the abscissa (x-axis coordinates) could have been in hours, and the ordinates (y-axis coordinates) in kilowatts. The area under each curve would then be kilowatt hours. Percentages were used in this instance because the average demand or loss can then be easily determined as a percentage of the peak value of the corresponding parameters.

Figure 3
DURATION CURVES — DEMAND AND LOSS



The 50% point on the time axis of the load duration curve will indicate the average load and therefore the load factor. On Figure 3, this value will correspond to the 61% previously calculated.

Loss Factor

In evaluating system losses, it is important to know not only the extent of power losses (kilowatts) which occur at times of peak system or feeder demand, but also the energy losses (kilowatt hours) which occur over a given period of time, usually a year. Modern microcomputer technology makes the calculation of peak demand losses relatively easy. Calculation of energy losses is more complicated however, since it is not feasible to make loss calculations for each of the hourly loads experienced during the period being evaluated. The energy losses are therefore usually calculated by application of what is known as the "loss factor." The loss factor is defined as the ratio of the average loss to the peak loss. The ratio is often expressed as a percentage. In other words, the loss factor is the percentage of the time which the peak load would require to produce the same energy losses as are produced by the actual load cycle during the same length of time. It may be calculated as follows:

$$\text{Loss factor} = \frac{\text{kWh of Loss During a Specified Time Period}}{\text{(Hours in Time Period) (Peak kW Loss)}} \times 100$$

As losses vary with the square of the demand, the latter parameter may be used to represent the losses, effectively being equal to the loss multiplied by a constant. Then:

$$\text{Loss factor} = \frac{\text{Summation of (Hourly Demand)}^2 \times 100}{\text{(Hours in Time Period) (Peak Demand)}^2}$$

In the example of Table 3:

$$\text{Loss factor} = \frac{4,109,800 \times 100}{435,600 \times 24} = 39\%$$

Note that in the summation of the squares of demand the frequency of occurrence (Column 3) must be considered.

Loss factors can therefore be calculated without knowing what the actual losses are, provided the variation of demand with time is known.

If the loss factor and the losses at times of peak demand are known for a specific period of time, then the energy losses in that period may be calculated by multiplying the peak losses by the number of hours in the period and by the loss factor. The loss factor must, however, be appropriate to the period being considered. Calculations of loss factors for a given day and for a year are likely to yield very different results.

The loss factor applies of course only to load losses, that is those losses which vary with the square of the load. No-load losses are independent of the load and are therefore not affected by the loss factor. For this reason, the terms "load loss factor" and "copper loss factor" are sometimes utilized.

Load losses being proportional to the square of the demand, it follows that the average losses will bear some relationship to the average load and hence to the load factor. Note however that the loss factor is seldom equivalent to the square of the load factor. This is so because the average of the squares of a group of numbers is not necessarily the same as the square of the average of those numbers. The loss factor is never greater numerically than the load factor, and never less than the square of the load factor.

The 50% point on the time axis of a loss duration curve will give the average of the squares of the hourly loads, or the square of the load factor. In the instance of Figure 3, this will correspond to 37%. This is not the loss factor in this example. The loss factor is the ratio of the area under the loss duration curve to the area enclosed within the rectangle formed by the two 100% boundaries. The loss factor for the load profile of Table 3 (or Figure 3) is 39%.

Unlike the load factor, the loss factor is not determined by peak demand and energy transferred alone. The variation of load with time is also important. Accurate calculation of the annual loss factor for any system or feeder would require the summation of the squares of the demands for each hour of the year. This would be a very tedious process and is seldom, if ever, done. More commonly, a typical sample period is taken and allowances made for seasonal variations, weekends, holidays, etc. Even then, the information required for certain feeders may not be available and estimates of the loss factor have to be made. In contrast, the data required to calculate the load factor is often readily available. An empirical relationship between load and loss factors has been established which generally yields results within tolerable limits of accuracy. This relationship states that:

$$\text{Loss factor} = c\,(\text{load factor})^2 + (1-C)\,(\text{load factor})$$

where "C" has a value between 0.15 and 0.3 depending on the load characteristics of the feeder or other system component being considered. In the absence of any data on which to base the choice of "C," a value of 0.2 may be used.

Loss Equivalent Hours

The loss factor represents the percentage of total hours which the maximum loss would have to last to equal the actual loss. Thus, if the loss factor over a year's time equals 0.20 or 20%, the equivalent peak-load loss lasts for 20% of the 8,760 hours in a year, or 1,752 hours. This value is called the annual loss equivalent hours. It is obviously possible to calculate daily, weekly or monthly loss equivalent hours, but the annual basis is normally the one of greatest practical significance. For the example in Table 3, the loss equivalent hours for the day would be 0.39 x 24, or 9.4 hours.

Peak Responsibility Factor

On each component or subsystem of a total system, the peak losses occur at the time of maximum demand of that component or subsystem, but this may not be at the same time as the overall system peak. For instance, the time of maximum demand on a specific feeder may not be coincident with the overall system peak. In that case, the contribution of the feeder to the system peak will be only a fraction of the peak on the feeder itself. The contribution of any component to overall system peak is determined by the "peak responsibility factor" which is defined as:

$$\frac{\text{Load on Component at Time of System Peak (kW)}}{\text{Component Peak Load (kW)}}$$

This factor is a measure of the probability of any given component experiencing its peak load at the same time as the system peak. A step-up transformer for a peaking generator will normally have a peak responsibility factor of 1. Conversely, the transformer serving an exclusively daytime load on a system with predominantly residential demand will achieve its peak loading coincident with the system peak, and its peak responsibility factor will be less than 1.

Figure 4 is a plot of the demands of individual feeders and of total system demand for a hypothetical system consisting of four feeders. The system peak occurs at 7:00 p.m., which is also the time at which Feeders 1 and 3 experience their peak demands. These two feeders therefore have peak responsibility factors of 1. Feeder 4 however reaches its peak of 930 kW at 2:00 p.m. At the time of system peak its demand is 670 kW. The peak responsibility factor of this feeder is therefore:

$$670/930 = 0.72$$

The peak responsibility factor assumes importance in determining how loss reduction measures carried out on a sub-system will affect the peak demand of the system as a whole. As an example, improvements carried out on a feeder which reduce the peak losses on that feeder by "x" kW, will reduce the overall system peak by less than "x" kW if the peaks are not coincident. This consideration will affect the economics of system upgrading to reduce demand losses as well as of evaluation of such losses for equipment purchase. Energy losses on a per unit basis are of the same importance as peak losses, except in those instances where off-peak fuel costs are lower. This could be the case, for instance, in a utility which uses gas turbines to meet the peak system demand but relies on more efficient diesel units to supply the off-peak or base demand.

The peak responsibility factor is a ratio of loads. The contribution of component losses to overall system peak losses will therefore be a function of the square of the peak responsibility factor.

Peak Loss Responsibility Factor

The peak loss responsibility factor of any system component is the ratio of the losses experienced by that component at the time of system peak to the losses at the time of the component peak load. From the previous paragraph, it will be seen that the peak loss responsibility factor is the square of the peak responsibility factor.

The internal losses of any individual system component will depend on its demand profile and technical characteristics. They (the internal losses) are therefore independent of the peak loss responsibility factor. The demand of that component, however, will increase the load on other system components between it and the power source. Therefore, other things being equal, a higher peak responsibility factor will have the effect of increasing the overall system loss.

Diversity Factor

A summation of the peak demands of individual consumers on any given circuit will produce a total which is greater than the peak demand actually experienced by that circuit. This is because the peak demands are not coincident. For instance, each householder does not use his appliances at exactly the same time as his counterparts. Appliances with cycling demands, such as refrigerators or water heaters, will not cycle in unison, The importance of this diversity in demands can be appreciated by considering the tremendous increase in system capacity-generation, transmission, and distribution--which would be required if all connected loads were imposed simultaneously.

The diversity between maximum demands is measured by the "diversity factor." This may be defined as the ratio of the summation of the maximum demands of a set of consumers to the actual maximum demand of the whole group. If diversity factor is abbreviated "DF," then:

$$DF = \frac{D_1 + D_2 + D_3 + \ldots + D_4}{D_{(1+2+3+\ldots+n)}}$$

where D_1, D_2, D_3 to D_n are the maximum demands of consumers Numbers 1, 2,3 to n respectively, without regard to time, and $D_{(1+2+3\ldots+n)}$ is the maximum demand of the group.

Referring again to Figure 4, the sum of the maximum demands of the four feeders is 660 + 840 + 1,250 + 930 = 3,680 kW. The system peak is 3,320 kW, so that the diversity factor of the feeders is 3,680/3,320 = 1.11. Diversity factors can, of course, be much larger than unity.

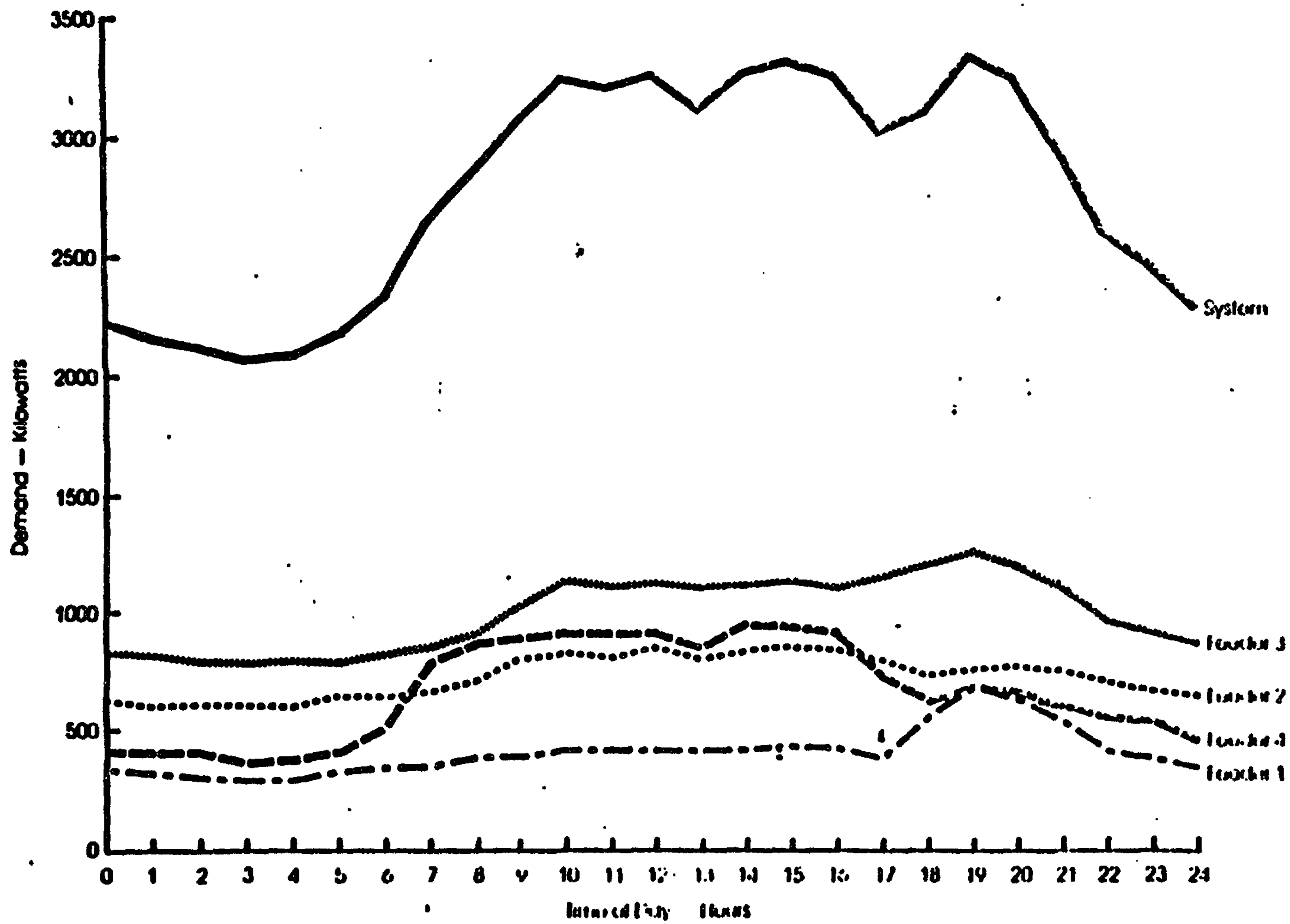
The diversity factor is used to determine the maximum demand resulting from a group of individual loads, or from combining two or more of such groups. These combinations may represent a group of consumers supplied by a single transformer, a group of transformers supplied by the same primary feeder, a group of primary feeders supplied from the same substation, etc., back to the ultimate point of supply.

The diversity factor is useful in determining the effect of different classes of consumers on the overall load demand profile. Numerically it is always greater than unity.

Coincidence Factor

The "coincidence factor" is the ratio of the maximum demand of a group of consumers to the summation of the groups' individual maximum demands. It is therefore the reciprocal of the diversity factor, and is numerically always less than unity.

Figure 4
HOURLY DEMANDS — FEEDERS AND TOTAL SYSTEM



Coincidence and diversity factors are usually applied to a group of consumers with similar power demand time profiles. These factors will have accuracy limitations if calculated for a small number of consumers. However, as the number of consumers increases, the contribution of each load to the group's maximum demand decreases and therefore increases the accuracy of the calculated factor. Figure 5 indicates the stabilization of the coincidence factor with increasing number of consumers.

Demand and Energy Losses

It is probably worthwhile here to review briefly the costs of system demand and energy losses. There is general agreement on the evaluation of energy losses as these are stated in kilowatt hours or other units of energy, and can in turn be translated into the cost of fuel required to generate these losses, or cost of energy purchased or value of energy not available for sale.

The treatment of demand costs is sometimes not so easily agreed on. At any given point in time, the system losses will impose a kilowatt demand on the system over and above that resulting from the consumers. This additional demand must be accommodated by the distribution, transmission, and generation systems. There are those who feel that demand losses form such a small proportion of total system demand that they have no influence on the timing and sizing of new generation, transmission or distribution installations. However, the generation, transmission, and distribution systems have no means of determining the source of the demand or distinguishing between a demand which will result in income to the utility and one which will be dissipated as heat to the atmosphere. No matter how small the demand losses they must be included in overall demand in system planning. In many instances, the level of losses are by no means small in comparison to the overall demand and form a significant component of the capacity planning to meet future needs. Technical losses in excess of 15% of peak system demand are not unusual in developing countries Reduction in the level of losses will therefore postpone the timing of new plant, and that postponement can be converted into a value in dollars and cents. The actual value of the reduction of losses by 1 kW will vary with the circumstances peculiar to each utility. It will also be dependent on where on the overall system the loss reduction occurs. Lower distribution losses will reduce investment in the distribution, transmission, and generation systems. If the transmission losses are reduced, however, only transmission and generation investments will be affected. It follows, therefore, that the greatest incremental benefits are obtained by reducing losses on the distribution system. This does not mean, however, that losses elsewhere ought to be neglected.

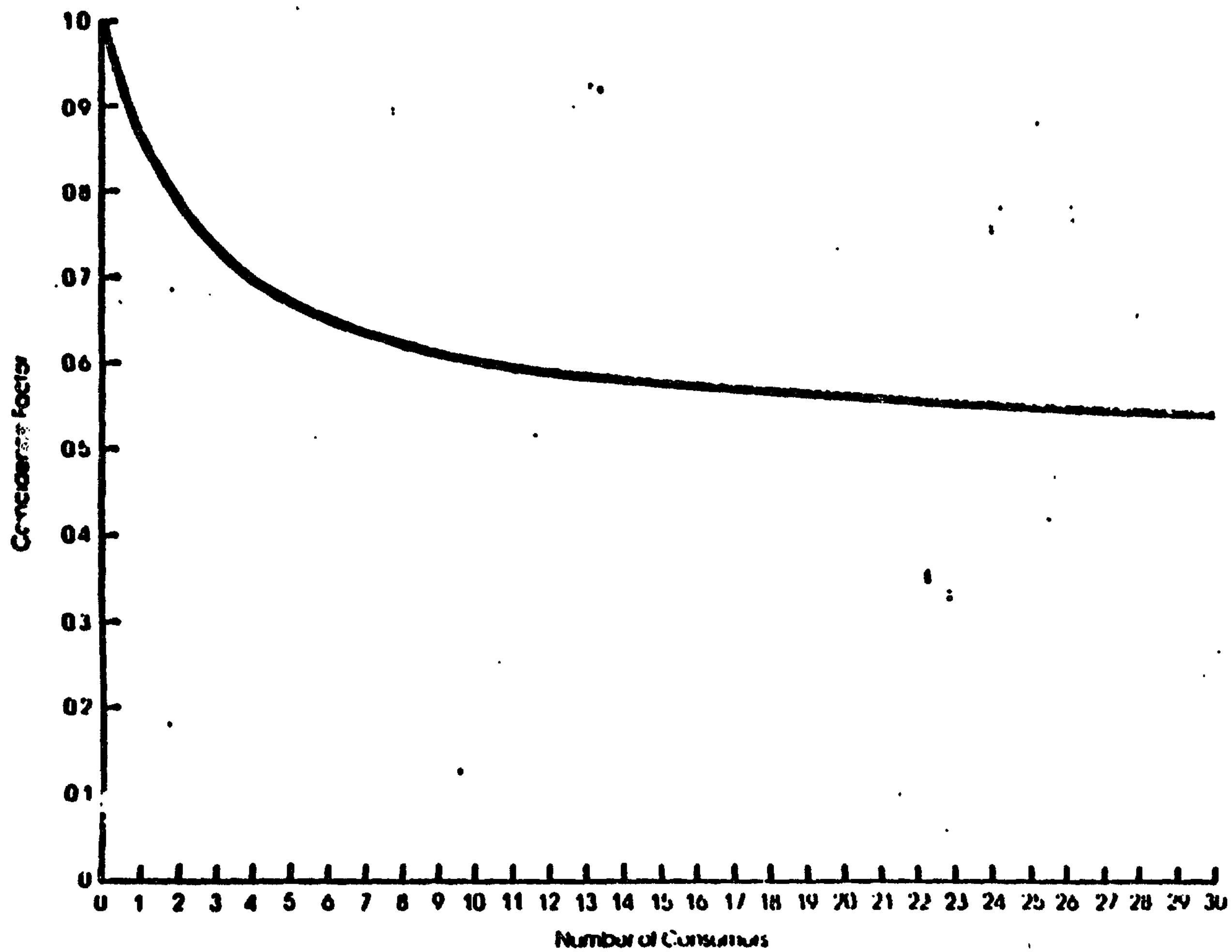
Loss Evaluation

Subsequent papers will describe in detail how losses on power systems are to be calculated, particularly using microcomputers It is, however, desirable that we review here some of the basic considerations in such evaluations.

Loss calculations require a certain minimum set of data. Important among those are:

(a) peak demand, seasons, and annual;

Figure 5
COINCIDENCE FACTOR
TYPICAL VARIATION WITH NUMBER OF CONSUMERS



KSR/World Bank V40551 S

(b) daily demand profiles, weekdays, and holidays--season;

(c) energy sent out, at least annually, preferably monthly;

(d) physical configuration of system, distances, spurs, phases, conductor materials, transformer locations and specifications, etc.

For economic analyses of loss reduction measures, information will also be required concerning the incremental cost:

(i) kilowatt of investment in generation, transmission, and distribution systems; and

(ii) per kilowatt hour of energy supplied at the transmission and distribution levels.

The cost of energy supplied at the distribution level is higher than at the transmission level because of the losses in the distribution system. Power is rarely supplied directly from the generating stations to the consumers, but in those instances where it is, the costs are lower than would have been the case for supply from the transmission system, again because of the losses in the transmission system.

The losses for a total system must be developed from analyses of the individual system components. Thus, each secondary distribution system, each primary feeder, each sub-transmission lines, and each transmission line must be calculated independently. The total system losses will then be the sum of the individual components, due allowance being made for the peak responsibility and factors in determining the system total. On large systems, the calculation of all of these system components individually may present practical problems because of the length of time that would be involved. In such instances, a realistic number of typical components for each category ought to be selected and the calculated loss values taken to be representative of the sub-systems

It is to be noted that the data required as mentioned above (load profiles, peak demand, energy sent out) will be required for each feeder or transmission line being calculated, and not merely for the overall system. It is therefore desirable that transmission lines and primary feeders be equipped with the appropriate instrumentation if a serious loss evaluation is to be undertaken. If the instrumentation does not presently exist, careful thought must be given as to how reliable estimates may be developed from the information currently available and from spot checks which can be made in an acceptably short period.

In order to determine whether a given loss reduction measure is economic or not, the benefit of the lower losses must be compared with the cost of the proposed measure. The benefits will be the sum of lower demand and energy costs. For simpler schemes, the calculation may be made on a straightforward payback period basis. This method is best suited to schemes which have very high returns--payback periods of about a year. For longer payback periods, the present value of costs and benefits ought to be determined over a period of 7-10 years. Due allowance must be made in such calculations for load growth on the feeder or other system components during the period of evaluation. The benefits of any loss reduction scheme will increase as the load grows, and it would be short-sighted to design efficiency improvement measures without evaluating their effect on future increases in peak demand and energy supplied. Whenever the decision is made to implement a system improvement project, some time will elapse between the decision and its implementation. The demand will normally have increased during that period and other system changes may have occurred. System improvements must therefore be designed for the conditions which will prevail at, and subsequent to, the time of implementation and not for the conditions which exist at the time of the decision.

Loss reduction schemes need frequent reevaluation to assess the effect of changing conditions, such as energy prices, load growth, etc. A scheme which was evaluated as being uneconomic a year ago may well prove attractive today. Conversely, schemes ought to be reassessed just before the commitment to expenditures is made to assess the effects of changed conditions on the economics of the project.

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ELECTRIC POWER SYSTEM LOSSES

JAMAICA PUBLIC SERVICE COMPANY LIMITED

BY

Messrs. R.A. Silvera and H. G. Higgins

Paper Presented at
Caribbean Regional Electric Power System Loss Reduction Seminar

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GENERAL

Jamaica Public Service Company Limited (JPS) is a publicly owned electric utility and is the sole supplier of electrical energy in Jamaica, operating under licence.

A. Technical Characteristics of the System

Generation

The company has a generating capacity of 442.5 MW supplied from two oil fired steam stations of 302 MW, one slow speed diesel station 40 MW, five gas turbines 80 MW and five run of the river hydro electric stations 20.5 MW (see Appendix 1).

Substations

There are approximately fifty-four (54) substations which step down from 69 kV transmission to distribution voltage levels with a total capacity of 655 MVA. Seven (7) bulk power transmission substations (138/69 kV) with a total capacity of 427 MVA also exists.

Transmission Lines

There are 171 circuit miles of 138 kV lines comprising nine circuits, interlinked with 445 circuit miles of 69 kV transmission lines. The system is predominantly of wood pole construction, but includes 90 miles of 138 kV and 42 miles of 69 kV on steel towers (see the attached map in Appendix 2).

Distribution System

The primary distribution system consists of approximately 7000 miles of lines operating at 24 kV, 13.8 kV, 12 kV and 4 kV. The system is presently being upgraded islandwide to operate at a standard voltage of 24 kV. Conductors used are all Aluminium Alloy in sizes 394.5 KCM, 155.4 KCM and 77.5 KCM. There are 118 primary distribution feeders existing.

Secondary voltage levels are 415 V and 220 V 3 phase and 220V/110V single phase.

B. Customer Management System

JPS maintains nine (9) district regional offices for the management of customers accounts. Applications for electricity service, establishment of customers contracts, extension of service, the conduct of meter reading and the collection of revenue are all functions conducted at District level.

The bulk of customers meters are read once every two (2) months. The meters of large customers (rate 50) are read monthly. Revenue billing is computerized and customers are billed monthly or bi-monthly depending on the level of kWh consumption. Actual revenues billed to customers are monitored, reviewed, adjusted where necessary and collected at the district level.

Receipting machines are used at District Offices in the revenue collection process to create and batch the collection data for the crediting of customers' accounts. Remote computer terminals at District Offices permit on-line access to recent customer accounts history on the central computer. These terminals also facilitate the conduct of revenue adjustment billing functions at the district level.

C. Electricity Demand and Load Forecast

Since 1980 extremes in the demand for electricity have been experienced. The system recorded a growtn rate of -4% in 1984 to 9.6% in 1986 in terms of peak demand and -1.15% in 1984 to 11% in 1987 in terms of energy sales.

Table 1 supplies details on electricity demand, forecast, sales and loss data.

D. Energy Losses

In recent years JPS electric system power loss, comprising technical and non-technical ('unaccounted for') losses has been in the region of 19% to 21% of net generation.

Various efforts have been made to quantify these losses and apportion percentages in the known categories. The most recent of these is a World Bank funded study on "Electric Loss Reduction" undertaken by EBASCO, a USA consulting firm. This was submitted to JPS in July 1988.

The approach used in the study was selection of a number of primary distribution feeders for detailed analysis and extrapolation to project losses for the entire system.

The EBASCO report allocates losses in the respective areas which total 19% of net generated energy, as follows:

		% of Total kWh Energy Generated
1.	Transmission system, including substation transformers	1.14
2.	Primary distribution lines	7.03
3.	Distribution Transformers	1.52
4.	Secondaries and services	4.18
5.	Unaccounted (non-technical)	5.13
		19.00

The annual cost of power losses on the system for 1989 is expected to be in the region of J$160 m.

E. Non-Technical Losses

The company has determined that its non-technical losses arise from both internal and external causes.

(a) Internal Causes:

(1) Defective Meters : mechanical or electrical failure in the component parts of the meter (10%)

(2) Incorrect meter multiplier constants - caused from incorrect field information or clerical effort (30%)

(3) Incorrect wiring - improperly installed wiring connections to meters (5%)

(4) Incorrect metering - wrong meter installed in socket (5%)

(5) Other - revenue billing errors such as incorrect meter readings, closed accounts with advanced readings and meters with advanced readings not appearing on the billing system (unbilled supplies). (15%)

(b) External Causes:

(1) Line Taps and bridged meters - unauthorized connections made to the line side before the metering point, including also bridged meters (10%)

(2) Direct connections - unauthorized direct connections to the company's lines to serve customers installations where no meter is existing. (5%)

(3) Tampered Meters - unauthorized interference with the meter mechanisms (backing pointers and adjusting gears etc.). (20%)

The percentages above reflect the estimated portion of total non-technical revenue loss, due to the causes indicated.

There is high incidence of electricity theft in Jamaica and is found among all income groups and consumer types. Electricity theft is a criminal offence in Jamaica and offenders if found guilty in a court of law, is liable to a fine and/or imprisonment.

F. Loss Reduction Programme - Non-Technical

The company established a Customer Service Investigation Unit (CSI) in 1982 to address the problem of electricity theft. Technicians from the unit accompanied by armed police conducted widescale investigations primarily in low-income communities. Those found in possession of an illegal supply of electricity were arrested and charged. The programme however, was not very effective economically. Technicians also spent long hours in courts. As well, police action in the communities targeted had only short-term effects and only a limited amount of revenue was collected during the four years of the Unit's operation.

In consequence, in November 1986, the company established a "Revenue Protection" pilot project with an expanded terms of reference. This project was subsequently enlarged into a permanent department with regional representatives in districts and was charged with responsibility for protecting the company from revenue losses of all kinds.

The Revenue Protection Department subsequently instituted a number of programmes. These include the following:

(a) CT Meter Audit Programme - a programme to audit all metering facilities which have current transformers installed.

(b) Investigation of whole current meters with consumption levels exceeding 2,000 kWh/month.

(c) Irregularity Investigation - where investigations are conducted randomly, also on the basis of customers reports received and at the discretion of the Department's management. A major meter resealing programme has subsequently been identified as one of the devices to contort irregularity.

As at May 31, 1989 the Department had conducted 9,760 investigations and discovered among them 1,403 irregularities. About 817 of these accounts with irregularities have been adjusted in the amount of J$4,495,000.00 of which J$3,310,000.00 has been collected. The revenue realizable from the adjusted accounts is estimated at J$1,740,000 annually.

G. Loss Reduction Programme - Technical

The company has recognized the benefits to be derived from power loss reduction in the technical areas and has outlined a series of projects to achieve the reduction of such losses on the system. These are discussed in order of priority.

1. Voltage Standardization Programme

This programme was started some years ago with the objective of converting all primary distribution circuits to operate at 24 kV. This project will have the greatest impact on energy losses when completed, due to the resulting substantially lower line currents and will also impact on the standardization of material and inventory. This exercise as well, has the potential to significantly increase distribution line MVA capacities thus deferring capital investments in upgrading of distribution lines and installation of new substations. The programme is approximately 30% completed.

2. Capacitor Installation

An active capacitor installation programme is currently being pursued on the primary distribution system. The objective of this programme is to achieve and maintain a system power factor of 0.95 against the current system power factor of 0.88. The reduced MVA demand will also assist in deferring investments in new generating plants.

3. Primary Distribution - Reconductoring

The company has standardized on conductor sizes for the distribution system and has recognized the need to reconductor all circuits operating with conductors below the economic loading limit. The studies and engineering for this project is expected to be included as part of a distribution master plan to be prepared for the company. Significant net savings is expected to be derived from this exercise.

4. Distribution Phase Balancing

A source of loss on the system is in the imbalance of phase currents on the primary distribution system. It is planned to balance phase loads on feeders so as to reduce energy losses arising from the high currents.

In addition, the company has pursued the following strategies or adopted as a matter of policy -

(a) Overlay of the old 69 kV transmission grid system with a 138 kV network. Energy losses on the transmission system is thus reduced resulting from the transmission of bulk power at a higher voltage on larger conductors.

(b) Procurement of energy efficient transformers to serve substations, customer pad mounted and distribution pole mounted installations.

(c) Use of larger conductors and service wires on secondaries and optimizing the locations of pole mounted transformers.

CONCLUSION

The combination of technical and non-technical loss reduction programme are expected to reduce total energy losses to a targeted level of 15% of net generation in the medium term.

The company has recognized the financial benefits to be derived and other advantages to be gained from the pursuits of these programmes and has herefore committed itself fully to their implementation.

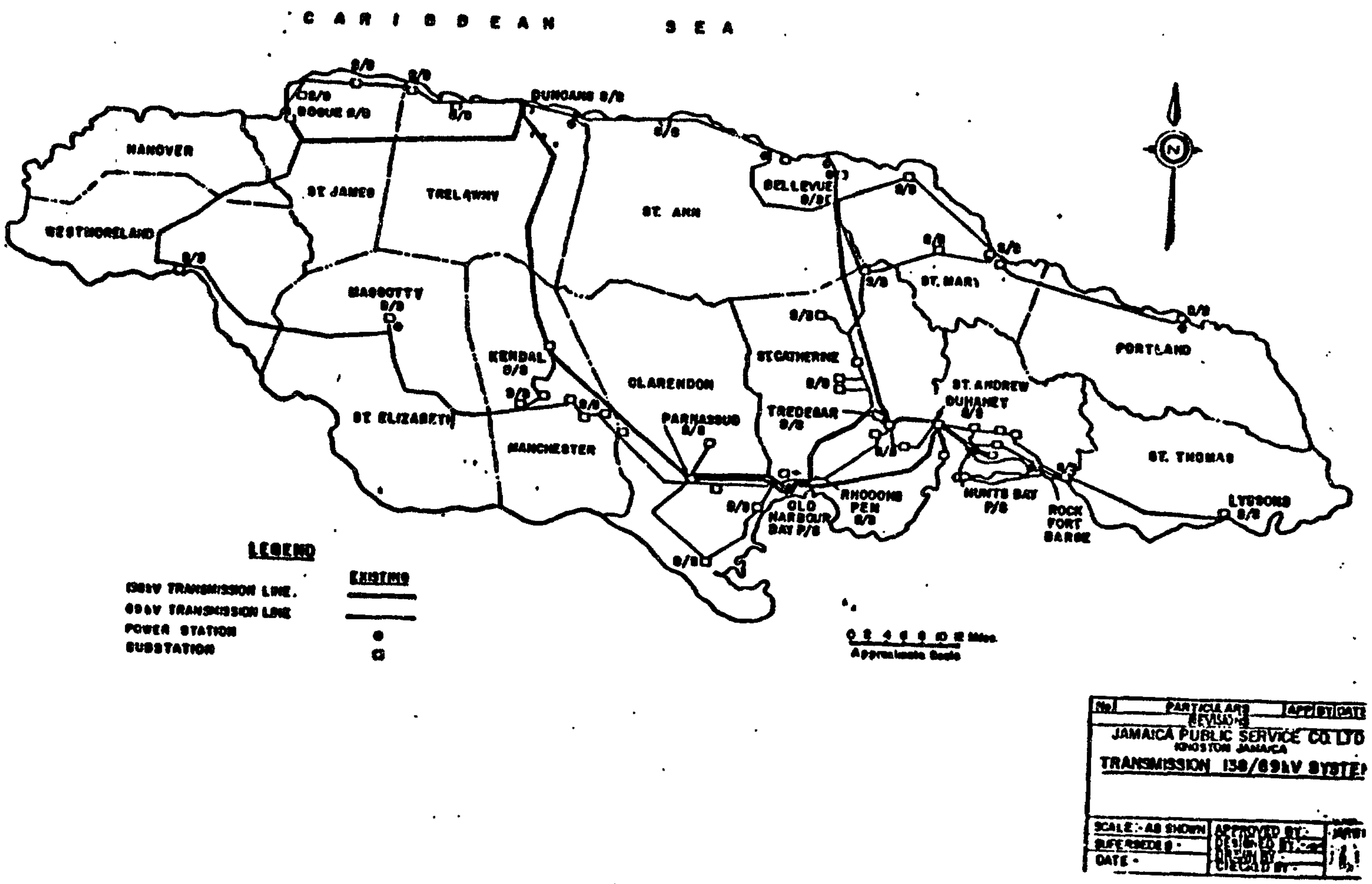
Appendix 1

EXISTING JPS GENERATING UNITS

Type	Station	Unit No.	Year Installed	Nameplate Rating MW	Maximum Continuous Rating (MW)
Steam-Electric	Old Harbour	1	1968	33.0	30.0
		2	1969	60.0	60.0
		3	1970	68.5	55.0
		4	1972	68.5	60.0
	Hunts Bay A	1	1953	12.5	
		2	1955	12.5	
		3	1959	15.0	
		4	1961	15.0	
		5	1962	20.0	20.0
	Hunts Bay B	6	1976	68.5	68.5
Total Steam Electric				373.5	293.5
Hydro-Electric	Maggotty		1959	6.4	6.3
	Upper White River		1945	3.2	2.6
	Lower White River		1952	4.8	4.7
	Roaring River		1949	4.1	4.1
	Rio Bueno		1956	2.5	2.5
Total Hydro Electric				21.10	20.2
Gas Turbines	Hunts Bay	1	1969	15.3	13.5
	Hunts Bay	2	1970	15.3	13.0
	Bogue	3	1973	21.1	20.0
	Hunts Bay	4	1974	21.1	15.0
	Hunts Bay	5	1974	21.1	18.5
Total Gas Turbines				93.8	80.0
Slow Speed Diesel	Rockfort	1	1985	20.0	20.0
		2	1985	20.0	20.0
Total Slow Speed Diesel				40.0	40.0
Total System		17		528.3	433.7

Jamaica Public Service Co. Ltd.

TRANSMISSION 138/69 KV SYSTEM



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Appendix 2

Appendix 3

PRIMARY DISTRIBUTION SYSTEM

1. 7,000 Circuit Miles

2. Operating Voltages

24 kV	-	Urban/Rural
13.8 kV	-	Kingston Area
12 kV	-	Rural Mainly
4 kV	-	Kingston Area

3. Conductor Sizes -

394.5 KCM)	
155.4 KCM)	All Alum. Alloy
77.5 KCM)	

4. 118 Primary Distribution Feeders

5. Secondary Voltage

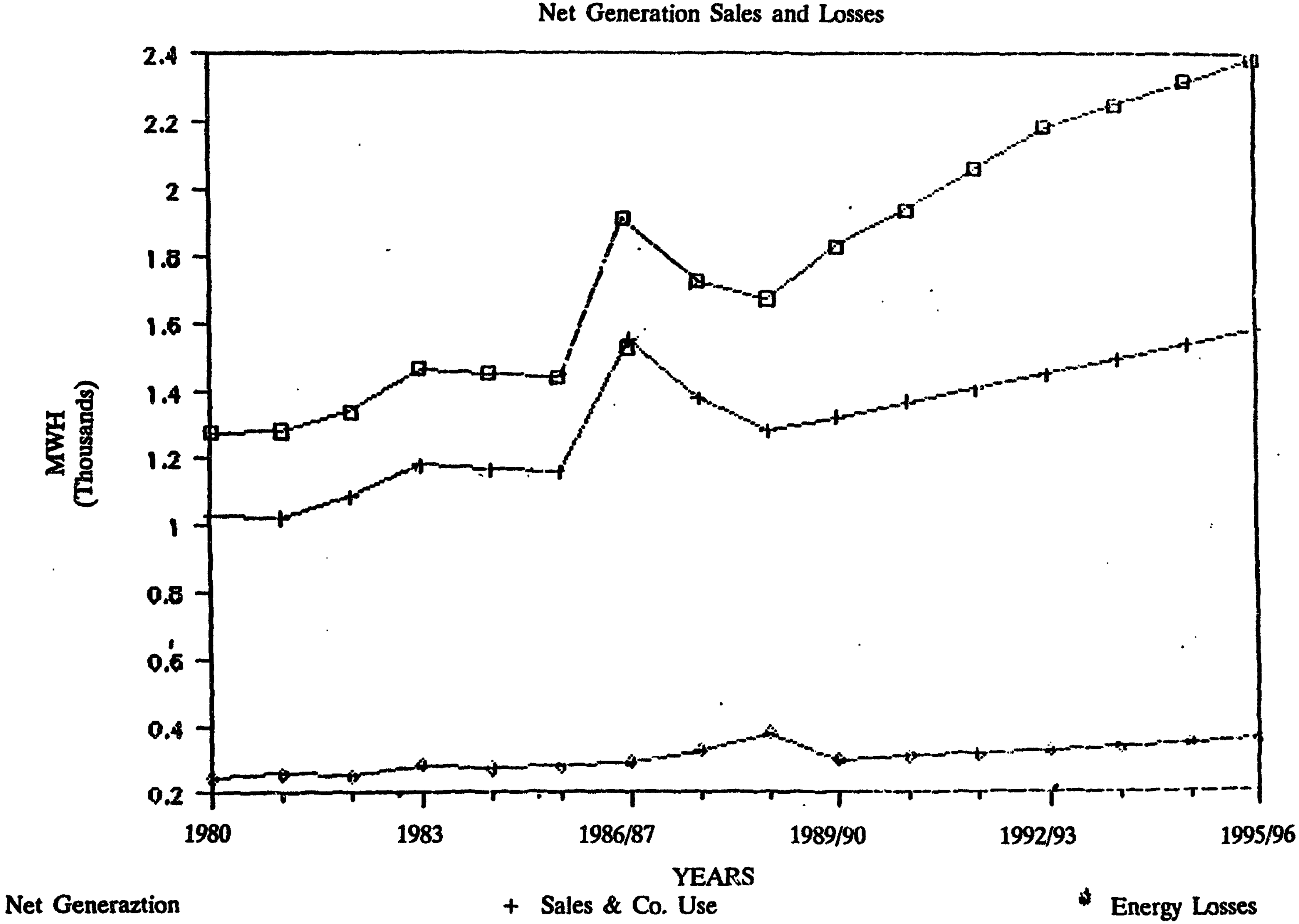
- 415 V WYE	)	
	)	3 Phase
- 220 V Velta	)	
- 220/110 V	-	Single Phase

JAMAICA PUBLIC SERVICE COMPANY
Electricity Demand, Forecast, Losses & Sales Data

	Year	Gross Generation (GWH)	Net Generation (GWH)	Sales & Co.Use	Energy Losses (GWH)	Net Losses %	Peak Demand (MW)	Residential % of cost '000	Residential kWh Sales	Comm/Indus (Small) % of Cost	Comm/Indus (Small) kWh Sales	Comm/Indus (Large) % of Cost	Comm/Indus (Large) kWh Sales	Other % of Cost	Other kWh Sales	Total % of cost '000	Total kWh Sales '000
	1980	1345.3	1275.0	1028.7	245.8	19.28	223.5	199.5	317537	23765	434846	23	133493	2229	136679	225.49	1022.6
A	1981	1357.8	1282.0	1023.2	258.6	20.17	223.8	208.4	314869	23876	431496	22	125718	2229	144945	234.52	1017.03
C	1982	1404.8	1338.0	1086.6	251.9	18.83	241.2	216.4	328607	24207	466885	22	138639	2221	144667	247.85	1078.8
T	1983	1523.9	1463.0	1178.2	284.7	19.46	256.5	220.7	365471	24329	524504	22	145945	2208	136552	247.23	1172.47
U	1984	1617.2	1448.0	1164.6	275.8	19.05	246.0	222.9	368111	24112	515135	22	142378	2160	131548	249.19	1157.17
A	1985	1523.9	1437.0	1156.4	280.5	19.52	263.1	226.1	340344	23849	516426	22	154007	2069	136568	252.06	1147.35
L	1986/87	1617.2	1525.0	1550.6	289.8	19.00	223.8	233.8	469261	24261	698839	24	212128	1910	161779	260.03	1542.01
	1987/88	1756.2	1721.9	1378.3	328.5	19.68											
	1988/89	1812.5	1669.0	1278.8	379.0	22.81	243.9	243.9	426415	25185	653934	24	166531	2176	123957	271.296	1370.84
F	1989/90	1921.3	1825.2	1321.6	300.0	16.44										278.08	1315.6
O	1990/91	2036.5	1934.7	1361.2	348.3	15.97										285.03	1355.2
R	1991/92	2158.2	2060.3	1402.1	318.5	15.46										292.16	1396.1
E	1992/93	2287.6	2158.2	1444.1	327.7	15.01										299.46	1438.1
C	1993/94	2424.9	2250.7	1487.5	337.6	15.00										308.44	1481.5
A	1994/95	2570.4	2318.7	1532.1	347.8	15.00										317.70	1526.1
S T	1995/96	2724.6	2388.0	1578.1	358.2	15.00										327.23	1572.1

15 Months

Jamaica Public Service Co. Ltd.



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Appendix 5

Appendix 6

REVENUE PROTECTION DEPARTMENT FINDINGS

	No.	%
Total Irregular Accounts Found	634	14
Total Accounts Checked and Found OK.	3897	86
Total Investigations Conducted	4531	100

Irregular Accounts	No.	%
Line Taps	107	16.88
Bridged Meters	7	1.10
Tampered Meters	135	21.29
Defective Meters	135	21.30
Incorrect Multipliers	8	1.28
Direct Connections	35	5.52
Incorrect Rate	156	24.61
No Account On System	26	4.10
Incorrect Wiring	16	5.52
No Registration On Phases	9	1.42
Total	634	100.00

Appendix 7

NON-TECHNICAL LOSSES

			% Of Loss Revenues
A.	Internal Causes		
	1.	Defective Meters	10
	2.	Incorrect Multiplier Constants	30
	3.	Incorrect Wiring	5
	4.	Incorrect Meters	5
	5.	Other	15
B.	External Causes		
	1.	Line Taps/Bridged Meters	10
	2.	Direct Connections	5
	3.	Tampered Meters	20
		Total	100

Notes:

(i) Approximately 10% of all customers comprising a strata consuming over 2000 kWh/month, use 80% of all power delivered to the sytem;

(ii) Approximately 14% of all Customer Accounts, supplies or metering systems are in error leading to revenue loss to the Company.

Appendix 8

LOSS REDUCTION STRATEGIES
NON-TECHNICAL

----

1. C.G. Meter Audit Programme.

2. Investigations of all customers Facilities with Consumption Levels Over 2,000 kWh/Month.

3. Irregularity Investigations.

4. Meter Re-Sealing Project.

5. Improvements of Internal Policy and Procedures Relating to Customer Accounts.

DEMAND MANAGEMENT

PAPER PRESENTED AT THE REGIONAL SEMINAR ON
ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN
KINGSTON, JAMAICA, JULY 2-7, 1989

By

Mr. Alfred Gulstone

- **DEMAND MANAGEMENT MAKES SENSE BECAUSE PEAK LOADS ARE EXPENSIVE TO SERVE.**
  - **MARGINAL COST OF SUPPLYING A CUSTOMER AT PEAK CAN BE IN EXCESS OF 60% HIGHER THAN OFF-PEAK**
  - **MAIN CONTRIBUTORS TO HIGHER COST ARE:**
    - **USE OF RELATIVELY INEFFICIENT GENERATING UNITS;**
    - **HIGH GENERATION MAINTENANCE COSTS CAUSED BY CYCLING UNITS;**
    - **HIGH TRANSMISSION AND DISTRIBUTION SYSTEM LOSSES (LOSSES ARE PROPORTIONAL TO I^2).**

- **THE OBJECTIVE OF DEMAND MANAGEMENT IS TO FLATTEN THE LOAD PEAKS AND FILL THE VALLEYS.**

Daily Load Curve

o THE MAIN BENEFITS ARE:

- LESS GENERATING PLANT
- GENERATING PLANT OPERATED MORE EFFICIENTLY
- REDUCED MAINTENANCE EXPENSE
- LESS TRANSMISSION AND DISTRIBUTION EQUIPMENT

o OTHER LESS OBVIOUS BENEFITS ARE:

- MORE EFFECTIVE PLANNING AND DESIGN AS A RESULT OF HAVING DETAILED INFORMATION ABOUT THE BEHAVIOUR OF THE SYSTEM LOAD RIGHT DOWN TO THE END USER.

- LOAD CONTROL MEASURES OFTEN RESULT IN CONSERVATION, I.E. THE PEAKS ARE SHAVED BUT THE ENERGY IS NEVER USED. THIS IS OFTEN A RESULT OF THE CUSTOMER'S INCREASED AWARENESS OF THE VALUE (AND COST) OF ELECTRICITY.

- WE MUST CONSIDER LOAD MANAGEMENT OVER TWO TIME PERIODS.

  - SHORT TERM

    - NOT MUCH OPPORTUNITY TO PERMANENTLY SHAPE LOAD.

    - OBJECTIVE IS TO RELIEVE IMMEDIATE OPERATIONAL CONSTRAINTS.

    - OPTIONS USUALLY LIMITED TO LOAD SHEDDING AND VOLUNTARY CURTAILMENT BY LARGE CUSTOMERS.

o LONG TERM

- DEMAND CONTROL BECOMES A PART OF THE SYSTEM EXPANSION PLANNING PROCESS.

- IT MUST BE CONSIDERED IN THE CONTEXT OF OVERALL LEAST-COST PLANNING.

- ONE DANGER THAT MUST BE AVOIDED IS TO ASSUME THAT DEMAND MANAGEMENT HAS NO COST. SOME OF ITS COSTS ARE THOSE RELATED TO:

    - METERING AND INFORMATION SYSTEMS

    - CONSUMER EDUCATION

    - MANAGEMENT AND ADMINISTRATION

- DEMAND MANAGEMENT MUST BE "INSTALLED" AS A COMPREHENSIVE SYSTEM.

  - WE WILL CONCENTRATE ON METHODS FOR IMPLEMENTING THE LONG-TERM STRATEGIES SINCE ONCE THE REQUIRED SYSTEMS ARE IN PLACE THEY CAN BE USED, WHEN NECESSARY, FOR SHORT-TERM LOAD RELIEF.

  - THREE FUNDAMENTAL REQUIREMENTS FOR SUCCESSFUL IMPLEMENTATION ARE:

    - APPROPRIATE INCENTIVES FOR CUSTOMERS.

    - CUSTOMER EDUCATION.

    - ADEQUATE INFORMATION AND CONTROL SYSTEMS.

- CUSTOMER INCENTIVES
  - CUSTOMER INCENTIVES ARE USUALLY RELATED IN ONE WAY OR ANOTHER TO TARIFFS.
  - THE USUAL OBJECTIVE IS TO APPROXIMATE AS CLOSELY AS POSSIBLE THE CONDITION WHERE THE CUSTOMER PAYS THE ACTUAL COST INCURRED IN PROVIDING HIS SERVICES. THIS INCLUDES:
    - (A) COST OF GENERATION
    - (B) COST OF LOSSES
    - (C) COST OF MAINTAINING A CERTAIN "QUALITY OF SERVICE"
  - SINCE THE (A), (B) AND (C) AT A GIVEN TIME OF THE DAY DEPEND ON THE SYSTEM DEMAND, AND IT IS NOT YET PRACTICAL TO MEASURE THEM CONTINUOUSLY, WE HAVE TO MAKE CERTAIN APPROXIMATIONS.
  - ANOTHER IMPORTANT CONSIDERATION IS THAT THE RESPONSE OF ONE CUSTOMER WILL CHANGE THE COST OF SERVING OTHERS. SO, WE CAN FOCUS FIRST ON THE CUSTOMER GROUPS THAT HAVE THE LARGEST IMPACT ON DEMAND SHAPE, AND STRUCTURE THE INCENTIVES TO MATCH THE BENEFITS THEY BRING TO THE SYSTEM.

- **CUSTOMER EDUCATION**

  - SINCE EFFECTIVE DEMAND CONTROL REQUIRES MODIFICATION OF THE WAY IN WHICH CUSTOMERS USE ELECTRICITY, THE IDEAS MUST BE "SOLD" TO THE CUSTOMERS.

  - CUSTOMERS MUST BE TOLD HOW IT WOULD BENEFIT THEM - THEY ARE NOT INTERESTED IN THE UTILITY'S PROBLEMS.

  - THE NECESSARY PROMOTIONAL ORGANIZATION CAN USUALLY BE ADDED TO THE CUSTOMER SERVICE DEPARTMENT.

  - IT IS OFTEN VERY EFFECTIVE IF THE TECHNOLOGY USED ALLOWS THE CUSTOMER TO SEE (IN REAL TIME) HOW MUCH HE BENEFITS BY REDUCING LOAD.

- INFORMATION AND CONTROL SYSTEMS

  - DEMAND MANAGEMENT SHOULD BE CONSIDERED AS ONE SUBSYSTEM OF A DISTRIBUTION AUTOMATION SYSTEM, SINCE THE COST OF THE NECESSARY DATA PROCESSING, METERING, AND COMMUNICATIONS CAN BE SHARED BY OTHER COST REDUCTION FUNCTIONS, SUCH AS:

    - LOSS MANAGEMENT BY LOAD DISTRIBUTION
    - TRANSFORMER LOAD MANAGEMENT
    - LOSS MANAGEMENT BY VAR DISPATCH

  - THE TECHNOLOGY FOR DISTRIBUTION AUTOMATION IS AVAILABLE NOW, AND A UTILITY SHOULD PLAN THE IMPLEMENTATION OF VARIOUS MODULES, SUCH AS DEMAND MANAGEMENT IN THE CONTEXT OF AN OVERALL DISTRIBUTION AUTOMATION SCHEME.

- **INFORMATION AND CONTROL SYSTEMS (CONTINUED)**

  - **TWO GROUPS OF SYSTEMS EXIST FOR DEMAND MANAGEMENT:**

    - **THOSE IN WHICH THE CUSTOMER IS SUPPLIED WITH EQUIPMENT WHICH SHOWS THE COST OF SERVICE AT ANY TIME, AND THE CUSTOMER CURTAILS USE IN RESPONSE TO THIS INFORMATION.**

    - **THOSE IN WHICH THE UTILITY DISCONNECTS PARTS OF THE CUSTOMER'S LOAD ACCORDING TO A PREARRANGED AGREEMENT.**

    - **IN THE CASE OF A PREARRANGED AGREEMENT, THE CUSTOMER SOMETIMES MAKES A CONSCIOUS DECISION TO INVEST IN ENERGY STORAGE EQUIPMENT TO TAKE ADVANTAGE OF THE INCENTIVES OFFERED BY THE UTILITY.**

O IN SUMMARY

- **DEMAND MANAGEMENT IS A VIABLE OPTION IN SYSTEM EXPANSION PLANNING.**

- **ITS IMPLEMENTATION REQUIRES THE USE OF A WIDE ARRAY OF TECHNIQUES, INCLUDING:**

  - **COMMERCIAL APPROACHES**
  - **INFORMATION SYSTEMS**
  - **COMMUNICATIONS AND CONTROL SYSTEMS**

- **IT SHOULD BE CONSIDERED IN THE CONTEXT OF OVERALL DISTRIBUTION AUTOMATION.**

REFERENCES

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EFFICIENT GENERATION - DIESEL

PAPER PRESENTED AT THE REGIONAL SEMINAR ON
ELECTRIC POWER SYSTEM LOSS REDUCTION IN THE CARIBBEAN
KINGSTON, JAMAICA, JULY 2-7, 1989

By

KLAAS KIMSTRA

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1. INTRODUCTION AND OVERVIEW

For the purpose of this presentation I grouped the items which influence generation efficiency into 2 parts:

- The first and larger part : Operation and Maintenance. This is the main subject of this presentation because it is in O&M where major influence can be applied on efficiency.

- The second and smaller part: Generating equipment.

This is a small section which addresses in a few words; (1) the influence of engine type on efficiency; (2) the potential of heat recovery; and (3) something about the so-called power turbine or efficiency booster.

2. OPERATION AND MAINTENANCE

Operation and maintenance aspects to be discussed here include:

(1) Fuel management
(2) Lube oil management
(3) Cooling water management
(4) Engine management
(5) Auxiliaries management
(6) Personnel management to make (1) thru (5) work.

Let us look at f management first.

2.1. FUEL MANAGEMENT

2.1.1. FUEL STANDARDS

Today's diesel fuels can broadly be divided into (1) distillates and (2) residual fuels, also called heavy fuels because of their high density. Properties of these fuels are defined in various national and international standards of which the ones most widely used are BRITISH STANDARD 2869, ASTM D 396 and D 975, and the CIMAC FUEL RECOMMENDATIONS. See References 1 to 3. The BS and ASTM are national standards, whereas the CIMAC RECOMMENDATIONS are issued by the INTERNATIONAL COUNCIL ON COMBUSTION ENGINES. This organisation unites engine users, engine manufacturers, component manufacturers and oil companies into a congress every two years which defines problem areas in diesel power and appoints committees from amongst its members to make recommendations. This CIMAC RECOMMENDATION on fuels is one such recommendation.

2.1.2. DISTILLATE FUELS

The use of often expensive destillate fuels is a must in smaller engines with, say up to about 250 mm bore. But also many stations with medium speed engines, which could successfully burn residual fuels run on distillate fuel because the local demand for residual fuel is too small for oil suppliers to offer an attractive price. The few operating problems distillate fuels sometimes cause are:

- Water. Causes corrosion of injection equipment and blockage of impregnated paper filter cartridges if water percentage is higher than 0.2 of a percent.

- Dirt. Blocks filters and damages injection equipment.

Both water and dirt enter the storage tank along with the fuel.

The rules to prevent this water and dirt from reaching the engine are:

(1) Use a simple closed settling tank with a capacity of about 30 minutes of max fuel consumption of the engine just upstream of the engine booster system. Such a settling tank is actually no more than an enlargement of the fuel transfer line to the engine booster circuit. In that place in the system the tank has an undisturbed flow pattern all the time. Water and dirt which have settled in this tank are not whirled up by the periodical inrush of a jet of topping-up fuel as happens in a storage tank or in a daily service tank

(2) Unless a proper water and dirt trap exists before the engine's filters, avoid drawing fuel from a storage tank from the moment filling starts till a couple of hours after the filling is finished.

(3) Use preferably replaceable element type final fuel filters of about 5 micron filter fineness.

The use of a centrifugal purifier for cleaning distillate fuels usually brings no improvement on top of what is achieved when the three rules above are followed.

- Low density and/or low viscosity. Densities as low as 0.82 @ 15 degrees Centigrade are sometimes met in medium speed engined powerstations. This is considerably lower than what manufacturers of medium speed and slow speed engines use on their testbeds.

These light fuels have a lower energy content per unit of volume, so more gallons of fuel must be pumped into the engine to give it a certain amount of energy per unit of time. This requires more fuel rack and so results in a longer fuel injection period which in it's turn causes an increase of fuel consumption in kJ/kWh.

Low density usually comes together with low viscosity, sometimes as low as 2 CS @ 40 degrees C. This lowers the volumetric efficiency of the high pressure fuel injection pumps which causes an additional increase in fuel rack required for a given amount of energy to be injected. This in turn again raises the specific fuel consumption of the engine.

These "expensive" effects of density and viscosity occur especially in modern engines with very short injection periods and very high injection pressures as are required for best fuel economy. Consult in such cases your engine manufacturer for retuning the injection system to recover up to 2% loss in efficiency.

2.1.3 HEAVY FUEL

Heavy fuel, consisting of high viscosity residual fuel to which (low viscosity) distillate fuel is added to achieve certain specified viscosities is a much more potential trouble maker than distillate fuels are. Heavy fuels are also specified in the standards already mentioned.

On top of the aforementioned internationally used standards most engine manufacturers issue detailed limiting fuel specifications, often per engine model, telling which is the maximum viscosity that is permitted and what maximum concentration they allow for sulphur, sodium, vanadium, catalytic fines (remains of cracking catalysts used in many refineries), water and other contaminants.

Also the tendency to deposit carbonaceous combustion products is kept in hand by specifying a maximum permissible value for the Conradson Carbon Number.

Relatively new and not yet laid down in internationally used standards are means to quantify the fuel's tendency to cause rough combustion and high peak pressures which can cause damage to piston rings and exhaust valves. Shell has developed for this purpose the so-called Calculated Carbon Aromaticity Index (CCAI). The CCAI performs for heavy fuels the same function as the Cetane Number for distillate fuels. This risk of rough combustion exists in heavy fuels which contain products coming from refineries equipped with so-called viscosity breakers which convert high viscosity fuel into lower viscosity components with often unfavourable ignition properties.

The CCAI is calculated from the fuel's density D (kg/m?+3? @15 C) and viscosity V (cs @ 50 C) as:

CCAI = D-81-141*loglog(V+0.85)

If this comes out higher than 860 then the fuel has a tendency for causing rough combustion and should preferably not be used.

A particularly unpleasant property in the handling of some heavy fuels (although not harmful for the engine) is their tendency to form excessive amounts of sludge, especially during heating and/or when subjected to high shear such as in pumps, centrifuges and filters. This property is called "thermal instability". In extreme cases centrifuges and filters may be choked with sludge every 20 minutes, which means that such fuels cannot be used.

There is no test for this property incorporated in a national or international standard yet, but major oil companies have developed test methods which are available to the user. One of these is the Shell Hot Filtration Test, which measures the amount of sludge formed after heating a sample of the fuel for a certain time and at a certain temperature. When the sludge formed in this test is more than 0.15% of the sample weight, the fuel is generally not considered fit for use.

Careful monitoring of the properties of each new charge of residual fuel with a view of avoiding engine damage is considered so important by large engine owners and ships classification societies, that special services have been created for carrying out ultra rapid analyses of each new charge before it is going to be used. See for more details the papers by C.FISHER and by F.A.RICHARDS and A.T.WOODFORD in Reference 5.

When the fuel properties are within the specifications indicated above, and the fuel treatment system is provided with modern centrifugal separators which operate at the right temperature and the right and constant throughput, the burning of heavy fuel can generate considerable savings on total cost per kWh generated for diesel power stations with large medium speed or slow speed engines and which generate at least some 25 GWh per year in average. This is of course only true when there exists an appreciable price difference between the two fuels. Recommendations for design of heavy fuel treatment plants can be found in the appropriate CIMAC RECOMMENDATIONS, see Reference 4.

2.2 LUBE OIL MANAGEMENT

That good oil filtration is of paramount importance for long engine life is no news. Just as for fuel, replaceable element filters with 5 to 10 micron effective filter fineness do a good job. They cost a little more per kWh generated than the coarser and washable gauze filters, but engine maintenance savings resulting from the cleaner oil outweighs this. A service life of these type of filter cartridges in the order of 1000 running hours for heavy fuel burning engines and to over 3000 running hours for distillate burning engines can be achieved, provided that centrifugal separators are used to remove the bulk of the dirt out of the oil.

Water is an enemy of oil. It enters the oil either from internal leakages in the engine or (and more often) as condensate from the combustion gasses which pass by the piston rings. About 1 litre of water enters the crankcase oil for every ton of fuel burnt. Normally this water escapes as vapour from the crankcase ventilation but cold drafts over the engine may cause water to condense against the inner side of the engine walls and then cause the water content of the oil to exceed the generally accepted 0.2% alarm limit. Centrifuging the oil at increased temperature (near to 100 degrees C) removes the water in a few days. A water percentage higher than 0.5% is generally considered reason to stop the engine to avoid damage to bearings and crankshaft. Dry the oil first to below that percentage before starting the engine again. It is worthwile to perform a daily check on water in the oil by doing the so called crackle test: dip a piece of toilet paper in a sample taken out of the oil circuit of the running engine and light it using a match or a cigarette lighter. If more than 0.2 percent water is present it burns with a crackling sound. If that is the case, determine the exact percentage of water by using one of the many test kits on the market for that purpose and decide if you can keep the engine running or if you have to stop it and dry the oil first.

Finally, have a spectrographical analysis made of a sample of the oil taken from the circuit of the running engine every month. This tells you about the condition of both the oil and the engine. Any undue wear shows up in an increased presence of metal, the sort of metal telling you where to look for the trouble in the engine. An example of a spectrographic analysis report is given in Annex 1. When the oil (and the engine) are cared for in the above described manner, life of an oil charge can often be extended to well over 10,000 running hours.

2.3 COOLING WATER MANAGEMENT

Scaling and corrosion are the the most frequent problems in jacket water systems. Reputable water treatment specialists market many good cooling water additives plus the chemicals necessary for checking and correcting of the cooling water quality. Checking must be done once a week or once a fortnight. For topping up demineralized water or treated condensate should be used. In turbocharged and intercooled engines operating in humid tropical climates much condensate forms in the combustion air when it passes the charge air cooler. This condensate can very well be drained into a condensate tank and be used as top-up water. Because condensate is slightly acid due to dissolved carbon dioxyde it must be neutralized in the condensate storage tank before being used as top-up water.

Evaporative cooling towers are frequent sources of trouble in dusty area's. In the cooling tower dust is caught by the water which deposits in the coolers in the tower water circuit. When in such area's evaporative cooling towers are
unavoidable then a closed intermedite water circuit should be used to keep the cooling tower water away from the jacket water coolers, lubricating oil coolers and charge air coolers.

To avoid all problems associated with open water circuits full radiator cooling is now often used, including air to air cooling of the charge air.

2.4 ENGINE MANAGEMENT

It goes without saying, that the engine must be operated in accordance with the manufacturer's instructions. But even then certain functions in the engine can deteriorate more quickly than usual under influence of outside parameters such as

- load pattern
- fuel quality
- lube oil quality
- cooling water quality
- air quality

It is of paramount importance to discover such deterioration in an early stage, so that either the outside parameters can be improved or the maintenance schedule be modified to keep the engine healthy.

2.4.1. FINGERPRINTING

An excellent method for early discovery of deviations is the use of the so called "Fingerprint System". This consists of taking a full set of readings of engine temperatures, pressures, etc. every, say, 4 weeks and of comparing the readings obtained with those taken four weeks ago and those taken during the commissioning of the unit.

Any differences between the figures obtained at each test and those obtained during the commissioning will tell the experienced engineer where changes in the engine have occurred and enable him to diagnose and remedy the causes at an early stage.

These fingerprinting runs should of course always be made at one and the same load (e.g. 75%) and (to further improve comparability) preferably also at the same day of the week and the same hour of the day.

The Fingerprinting System described above can be extended to include vibration characteristics measured at a number of places on the engine. See Annex 6.

Results of vibration measurements on the engine should be handled with care if misinterpretation of measurement results is to be avoided. Operating such equipment and interpreting the results of measurement requires some special skill. If one wishes to include vibration in the fingerprint then the best method is probably to measure the vibration velocity levels at a number of defined spots on the engine. When deviations from previous readings occur, then a further measurement should be done using an instrument with frequency analysing capability. Interpretation of the results therefrom is a specialists' job. For criteria, see References 6 and 7.

A prerequisite for drawing the right conclusions from this Fingerprinting is that the engine's and the auxiliaries' instruments can be trusted to give the right numbers. This can only be the case when checking and subsequent adjustment or replacement of instruments is an integrated practice in the power station. This means that it is done at regular intervals, preferably when the engine is out of operation for planned maintenence so that the engine does not run with part of it's instruments sitting in the instrument workshop.

Thermometers up to 100 C can easily be checked by using melting ice and boiling water. Calibrated spare thermometers should be in stock for putting into place of suspect charge air and exhaust gas thermometers.

For calibrating pressure gauges and pressure switches, relatively cheap and easy to handle hand operated pneumatic equipment is on the market.

2.4.2. ENGINE PROTECTION AGAINST ABNORMAL OPERATING CONDITIONS

The risk of costly engine failures can be reduced by maintaining the engine protection system in proper order, protection against low oil pressure being the most important one. Pressure switches and temperature switches should be checked and calibrated on an engine running hours and time schedule.

When checking engine trip systems one should not overlook the loop which opens the generator circuit breaker. If this loop does not work all other engines on line will cooperate in milling an engine to pieces which ought to have stopped following its low oil pressure trip action.

2.4.3. ENGINE OVERHAUL PRACTICE

Engine manufacturers specify intervals by running hours or calendar time after which inspections and overhauls should be done Following these instructions all similar components are usually serviced all together at the same time, e.g. all pistons are pulled, cleaned, reringed, etc. in one job.

Many users however have benefitted by modifying this sequence to pulling half the number of pistons at half the specified number of running hours and pulling the remaining ones at the specified number of hours (then leaving the first half untouched) and pulling the first half again after they have done the specified number of hours. In the marine world this is called the Continuous Survey (CS) method of maintenance. This CS method has three advantages over the standard method:

(1) Down time per overhaul job is less, which allows the job to be done more easily and finished in a period of time when the engine is not required (week-end).

(2) It allows an in-between check on component condition, which may induce lengthening or shortening the overhaul interval for optimum results.

(3 In case one has decided to use exchange components to speed-up the overhaul, for instance, to exchange cylinder heads complete with valves, thus allowing the valve job on the heads which came off the engine to be done after the engine went back into service, only half the number of exchange components is required.

This continuous survey method is sometimes used with considerable success. One particular station with two 3.25 MW units burning 380 CS heavy fuel has managed to maintain an average of over 8200 running hours per engine annually already during 4 years.

2.4.4. AIR FILTERS

The oil-wetted revolving screen type of filter is the most widely used in not too dusty areas. It works well provided its oil bath contains oil and not rainwater which has driven out all oil as is sometimes found. It must therefore be avoided that rainwater reaches the screen by either placing the filter inside a plenum chamber or by providing it with an effective type of rain screen.

2.5. AUXILIARIES MANAGEMENT

The availability of the diesel engine depends considerably on the availability of its auxiliaries amongst which pumps and radiators are the most important ones. For this type of equipment Finger Printing by taking vibration readings at regular intervals reveals such things as misalignment between electric motor and pump, loosening of bolts which keep radiator motors in place, cracks in steel structures of large radiators, etc all before these defects have grown to the stage of causing break-down. Repairs and adjustments should of course be logged into the Equipment History Logbook. See Annex 3 for an example of vibration measurements for a cooling-water pump.

2.6. PERSONNEL MANAGEMENT

Few things get properly done by people who lack the enthusiasm to do things and to do them right. Everybody knows that there is much pleasure and satis-faction in getting tangible results from using knowledge or skills one has acquired in whatever way. This mechanism - learning and successful application of what was learned - has always been the necessary nurturing for enthusiasm and curiosity which brought new knowledge and results, and so on.

This also applies to work in the (larger) diesel power stations, which will always remain tailor made, very much different from a mass product as a car which you can drive without even knowing whether the engine is under the hood or in the trunk. This cycle of learning - application -learning is in power stations nowadays often interrupted because of the ever increasing pace at which new sophisticated techniques and equipment enter the scene, both in the field of diesel operation and diesel maintenance. Even the good old diesel engine now carries a harness of electronics and has also in other aspects developed into a complicated and sophisticated machine.

The key to solve this problem cannot be anything else than "permanent education" of diesel power station personnel by the participation in external courses, especially on the subjects of instruments and control, fuel and lube oil treatment as well on certain areas of the engine itself such as fuel injection, bearings, pistons piston rings and liners. And even then, the Ten Commandments for Diesel Engine Maintenance, will remain true, Figure 1.

3. GENERATING EQUIPMENT

A few things about station design as far as they influence efficiency have already been touched upon in the foregoing. Three special things will be addressed under the heading of this section.

The first is the effect of cylinder dimension upon specific fuel consumption. When comparing two engines of different cylinder size but of comparable technological level one will always find that the "bigger" engine has a lower specific fuel consumption than the "smaller" engine. This results from the fact that friction losses and heat losses become relatively smaller the bigger the engine becomes. Fig. 2 illustrates this effect. By rule of thumb one can say, that increasing of the bore by 50% lowers the fuel consumption per kWh by about 5%. This means that for a given power demand the fuel bill will be lowest when engines with the largest possible cylinder dimensions and thus with the lowest possible number of cylinders are selected. This low number of cylinders brings another advantage, namely the higher availability of engines with less cylinders.

Unfortunately the cost per kW of a 6 cylinder engine, of say 3 MW, is higher than of an 18 cylinder unit of the same output. Depending in part, on the required load factor of the engine (which is largely a function of the demand profile of the station) and the fuel price an optimum "engine size" can be found. In most cases this turns out to be a big bore/few cylinders model. An approach to quantify this effect was made in SWDiesel Review No. 40 of June 1987 (Reference 8).

The second item to be mentioned here is the use of waste heat from the diesel engine. Figure 3 shows a typical heat balance for a turbocharged intercooled diesel engine. From the diagram in this picture it can be seen that the usable exhaust gas heat is up to about 40% of the generator power over most of the load range. When also heat at 95° C can be used the total usable heat goes up to 60% of generator power. This can mean a considerable saving on fuel cost for water desalination as an example. Note, that in case of the use of high sulphur heavy fuels exhaust gas should not be cooled much under 200° C to avoid boiler and stack corrosion.

The third and last item to be mentioned here is the power turbine or efficiency booster which is a new development in diesel generation. Modern turbocharged medium speed diesel engines have a slight excess in exhaust gas pressure before the turbine of the turbocharger. For low specific fuel consumption it is advantageous to divert about 25% of the exhaust gas the engine produces before the turbine of the turbocharger and to duct this into a small separate turbine which can either be geared to the diesel engine shaft or to a separate generator. The fuel saving in g/kWh generated is between 2 and 3%. The ultimate cost saving depends on fuel price and very much on the load factor of the generating unit concerned.

Figure 4 shows a schematic arrangement of an engine and a power turbine in which the power turbine drives an asynchronous generator.

LIST OF REFERENCES

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3. International Council on Combustion Engines (CIMAC), 10 avenue Hoche, 75382 Paris CEDEX 08, France: Recommendations regarding Requirements for Heavy Fuels for Diesel Engines, second edition, June 1985.

4. Ditto: Recommendations concerning the Design of Heavy Fuel treatment Plants for Diesel Engines; December 1987.

5. The Institution of Diesel and Gas Turbine Engineers (IDGTE), 18 London Street, London, EC3R7JR, UK. Tel (1) 481 2393: Second International Conference, London, March 16, 1989; papers nrs. 2 and 9.

6. ISO 2372: Mechanical vibration in rotating and reciprocating machinery.

7. The Institution of Diesel and Gas Turbine Engineers (IDGTE), 18 London Street, London, EC3R7JR, UK. Tel (1) 481 2393: Health and safety aspects of diesel power stations. Publication 434, October 1986.

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Figure 1

Ten Commandments
for Diesel Engine Maintenance

Keep thine engine clean and in adjustment that thy life in its company shall be long and that the owner shall increase thy pay.

Know thine engine and all its parts and functions, else thou shalt be in some unholy spot.

Be not wise in thine own conceit. Remember the factory instructions and keep them holy, lest repairs be thine undoing.

Be not loose in thy jaw hinges for no man knoweth all about diesels. The truly wise absorbeth much knowledge and exceedeth little, and he who so doeth shall gain repute among his fellows and favors among his superiors.

For all things in this life that thou desireth thou shalt also pay plenty and for the wisdom of experience, no less. Advice from the multitudes costeth nothing and is usually worth just that.

In the books thou mayest read what to do and when, but only the voice of experience may tell thee why and how, else thy reading of what and when shall but plague thee with smoke.

God maketh the earth to rotate endlessly without bearings, or oil, but not thy diesel.

Curse not thine engine when it turneth not. Curse rather thine own stupidity.

Steam engines and gas engines may long turn over though sloppy; a diesel not so. With gauges and mikes be thou ever busy.

The eternal eye watcheth universal operations, but thou shalt not rely upon it as to thy diesel. Thine own vigilance is the price thou payest for thy job.

DECREASE OF SPECIFIC FUEL CONSUMPTION WITH INCREASE OF CYLINDER DIMENSIONS

DECREASE IN SPECIFIC FUEL CONSUMPTION

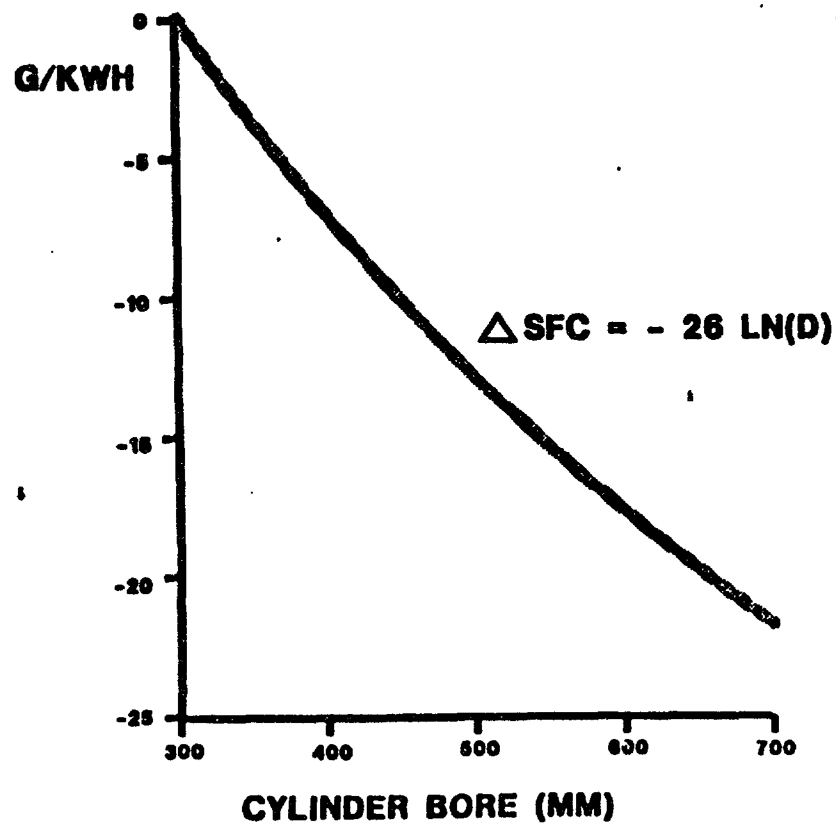


Figure 2

USABLE WASTE HEAT IN % OF GENERATOR OUTPUT AS A FUNCTION OF GENERATOR LOAD

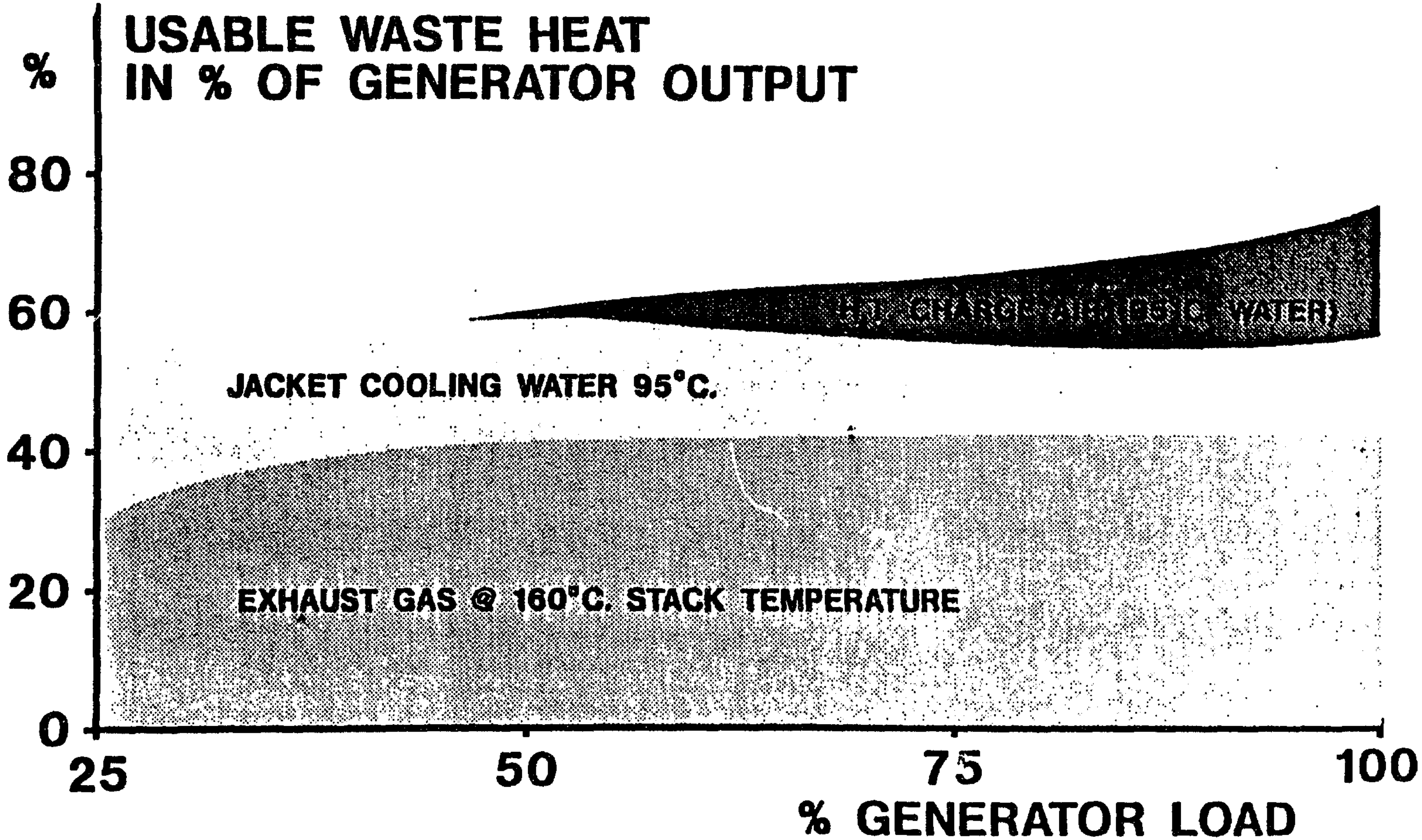
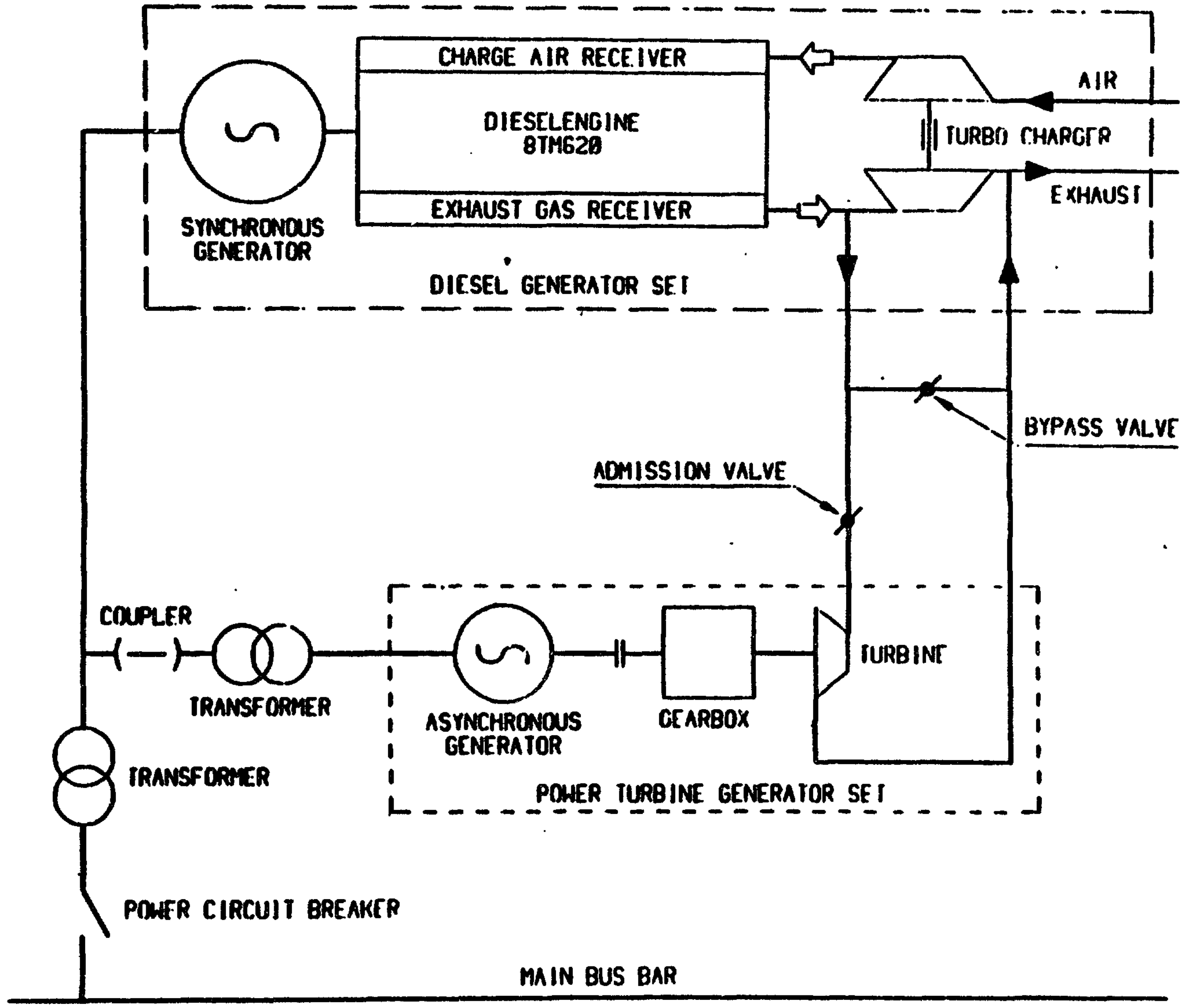


Figure 3

Figure 4



INTERCONNECTION OF DIESEL ENGINE UNIT
AND POWER TURBINE UNIT

bos ANALYSIS REPORT

Annex 1/1

STORK WERKSPOOR DIESEL B.V.
DHR. C.H. VERBERNE
POSTBUS 4196
1009 AD AMSTERDAM

BOS-Registration number	: 973628
Machine	: DIESELMOTOR
Make	: STORK
Type	: 9 TM 620
System capacity	: 15 m3
Oil grade	: ARGINA T 40

Dear Sirs,

Here are the results from the laboratory analysis of the received oilsample.

Date drawn	09-05-89	28-04-89	17-04-89	10-04-89	31-03-89	23-0[illegible]
Analysis date	19-05-89	17-05-89	24-04-89	24-04-89	11-04-89	06-0[illegible]
Sample number	345857	345856	345855	345854	345853	3456[illegible]2
Machine hours	3.772	3.582	3.329	3.155	2.963	2.8[illegible]
Oil hours *	3.772	3.582	3.329	3.155	2.963	2.879
Oil added, l *	2.496	2.496	2.496	2.496	2.496	[illegible].486
* since last oil change						
Visc. at 40.C, mm2/s	154.4	150.4	153.2	158.7	164.0	158.4
Visc. at 100.C, mm2/s	14.9	15.1	15.4	14.8	15.0	1[illegible].8
Flash cc, .C	> 190	> 190	> 190	> 190	> 190	> 190
Watercontent, % v/v	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
TBN, mg KOH/g	25.0	24.3	23.6	22.4	22.2	21.5
Combustion soot	0.27	0.21	0.20	0.26	0.21	0.23
Dispersancy	88.4	89.3	84.1	85.0	75.5	81.8
Calcium, % m/m	0.99	1.00	0.94	0.84	0.82	0.94
Barium, % m/m	0.00	0.00	0.00	0.00	0.00	0.00
Phosphorus, % m/m	0.04	0.04	0.04	0.04	0.04	0.04
Zinc, % m/m	0.05	0.05	0.05	0.04	0.04	0.04
METAL-ANALYSIS:						
Silicon, mg/kg	0	0	0	0	0	0
Iron, mg/kg	0	0	0	0	0	0
Aluminium, mg/kg	4	4	4	5	5	5
Chromium, mg/kg	2	2	1	1	1	1
Molybdenum, mg/kg	0	1	0	1	2	0
Copper, mg/kg	1	1	1	1	1	1
Tin, mg/kg	0	1	0	0	0	1
Lead, mg/kg	0	2	0	7	0	0
Nickel, mg/kg	6	5	4	4	4	5
Manganese, mg/kg	2	1	2	1	1	1
Silver, mg/kg	0	0	0	0	0	0
Vanadium, mg/kg	18	17	15	12	13	14
Comments**:	95	95	95	95	95	95

Shell Nederland Verkoopmaatschappij B.V.
Dealt by : MLI
Phone :

** For explanation of commentcodes p.t.o.

COMMENTS

Annex 1/2

CURRENT SAMPLE:

95 ALL ANALYSIS FIGURES ARE WITHIN NORMAL LIMITS AND DO NOT NEED TO BE COMMENTED. THE OIL IS FIT FOR FURTHER USE.

PREVIOUS SAMPLES

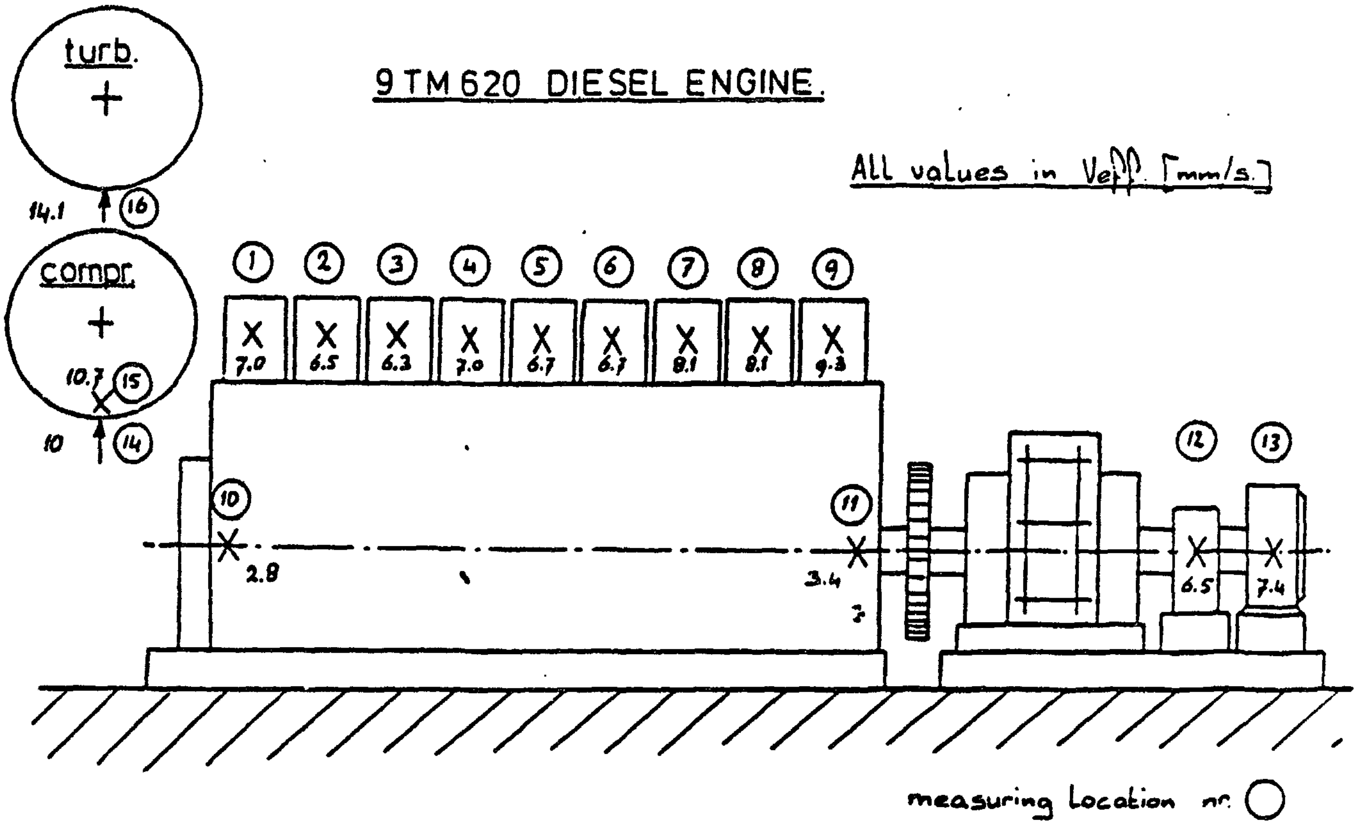
95 ALL ANALYSIS FIGURES ARE WITHIN NORMAL LIMITS AND DO NOT NEED TO BE COMMENTED. THE OIL IS FIT FOR FURTHER USE.

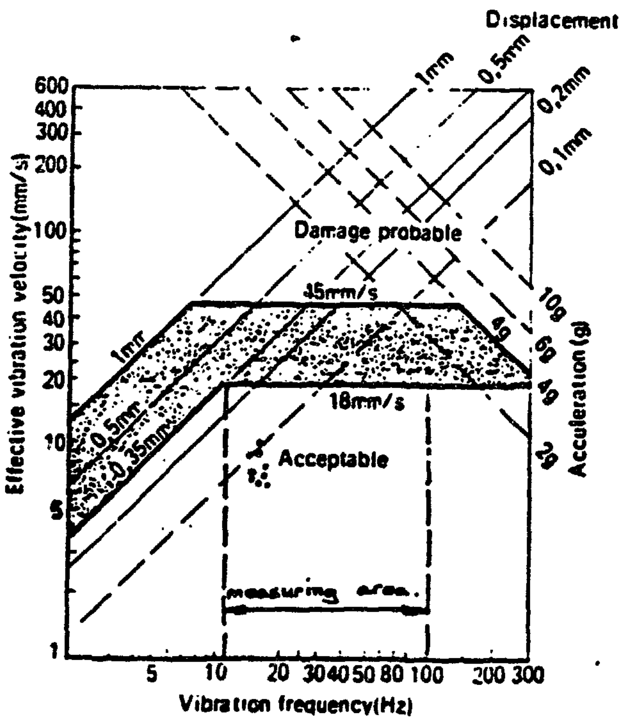
When investigating and producing the analysis figures we presume that the sample fully represents the indicated oil charge. Except in the case of gross negligence on our side we do not accept responsibility for the recommendations given.

Shell Nederland Verkoopmaatschappij B.V. Established in Rotterdam. H.reg. Rotterdam 11 29 07

Annex 2

VIBRATION-LEVELS





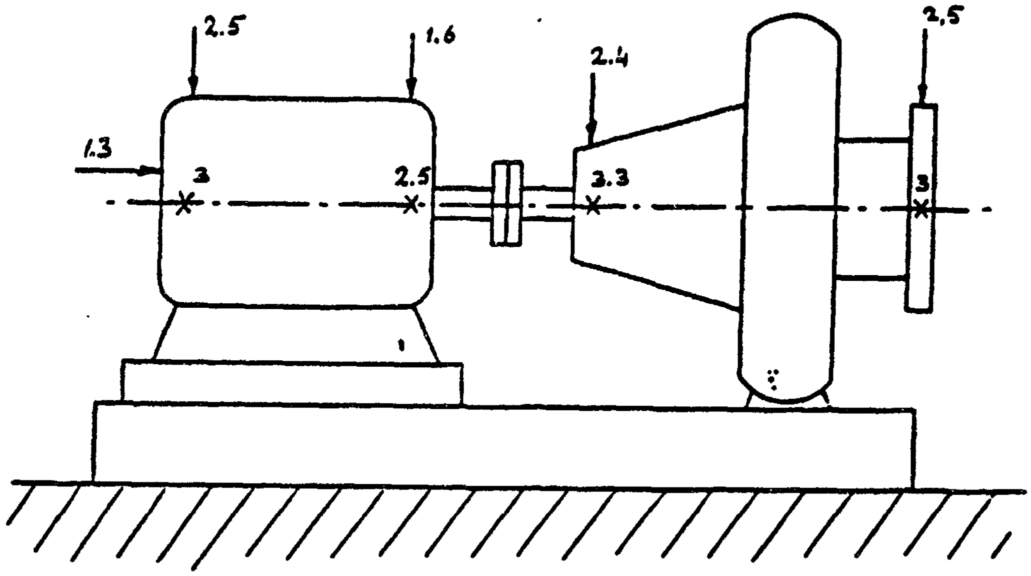
Effective vibrations at cylinder head level of diesel engines

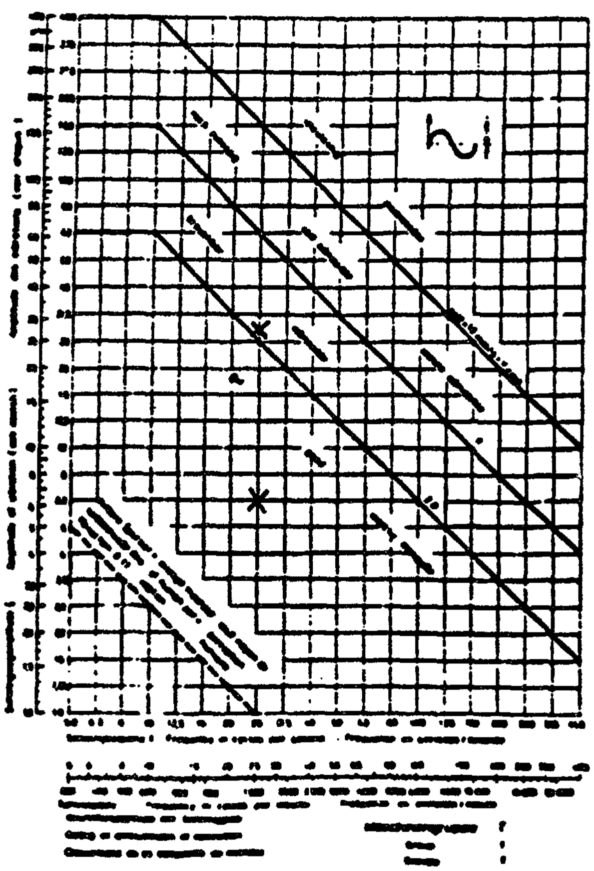
Go/ no go criteria
IDGTE publ. nr. 434 Oct. 1986

Annex 3

VIBRATION-LEVELS

COOLING-WATER CIRCULATION PUMP A





ALL values in Veff [mm/s]

Go/no go criteria
ISO-3945

WAYS TO REDUCE TRANSMISSION AND DISTRIBUTION LOSSES

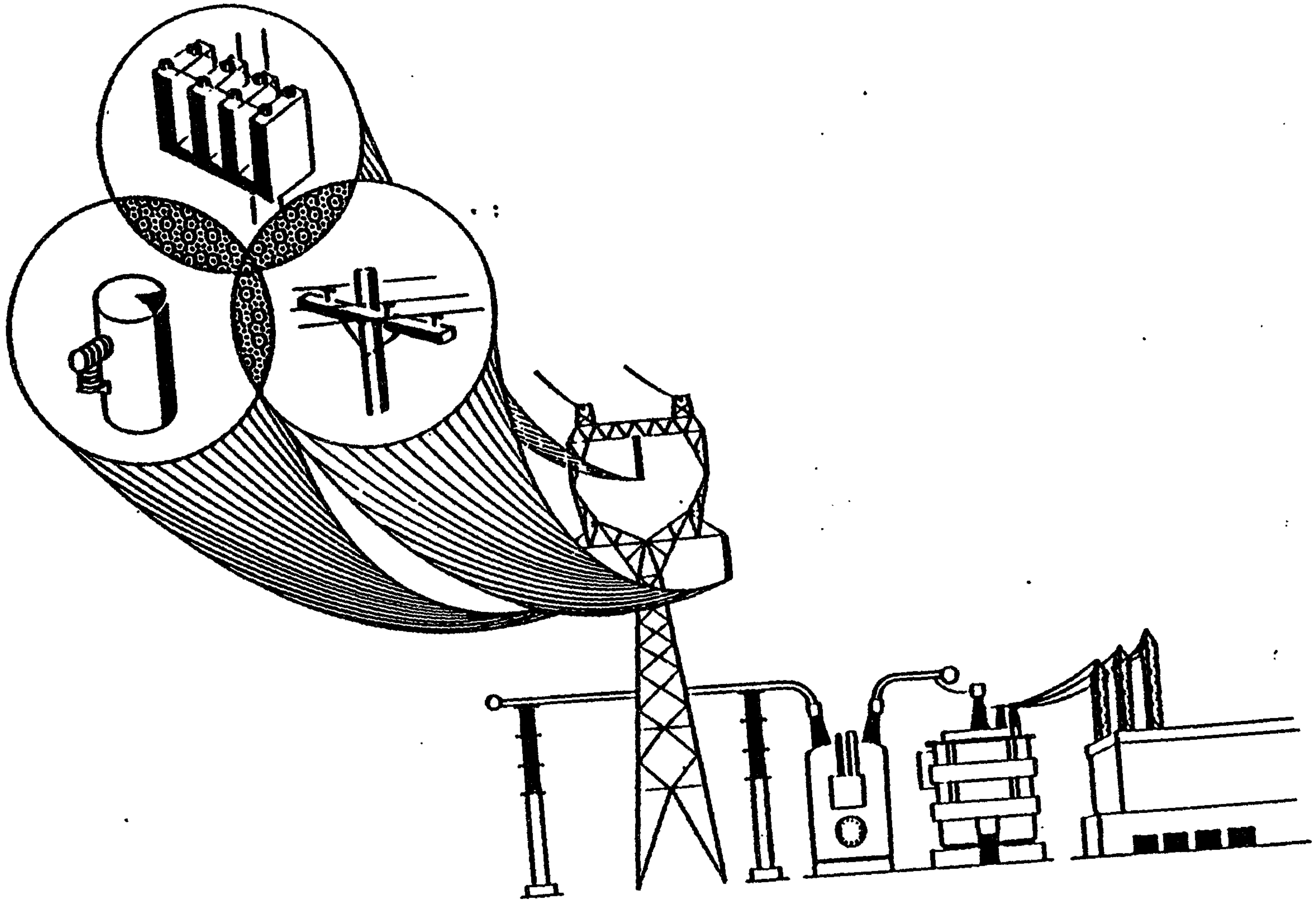
AND

WAYS TO REDUCE TRANSFORMER LOSSES

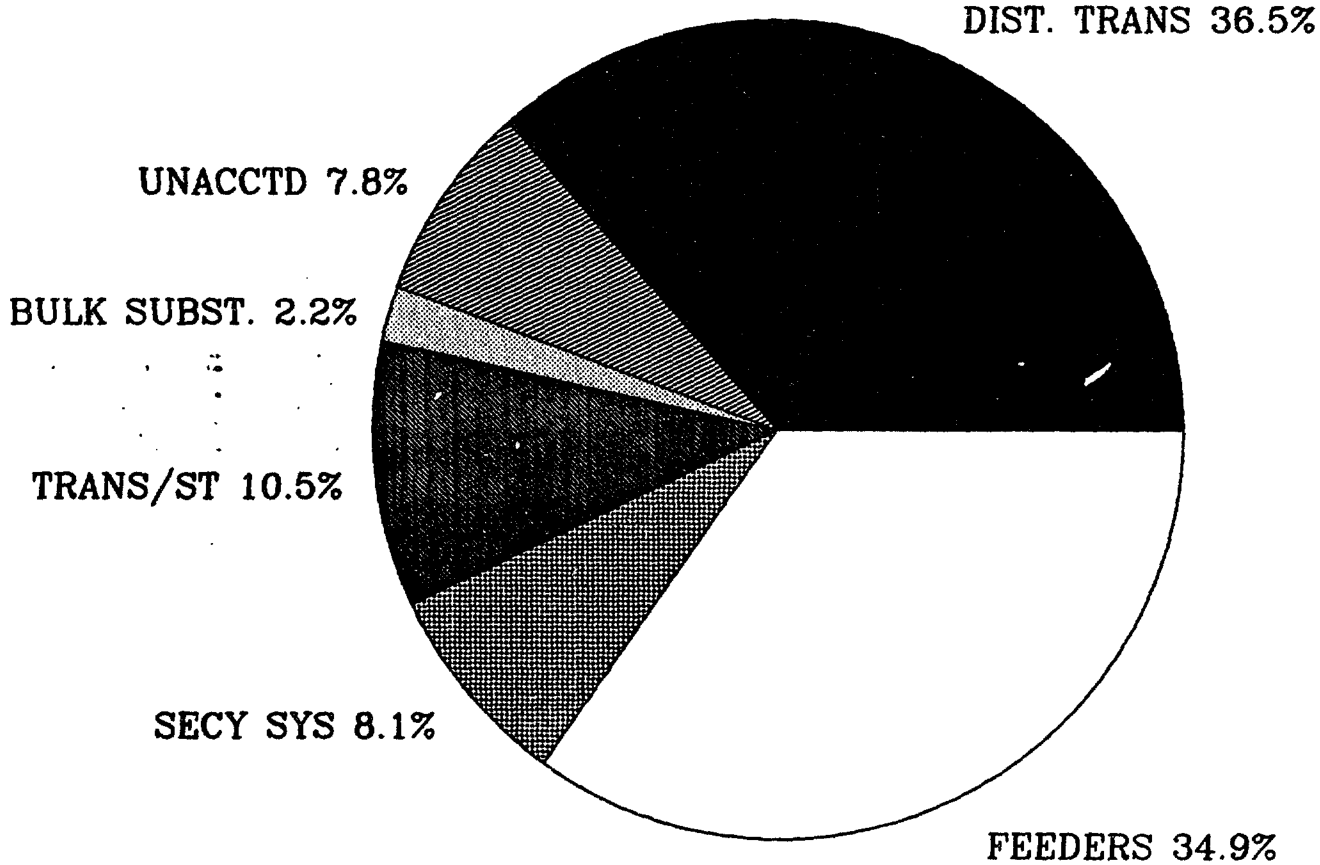
By

Mr. Barry Kennedy

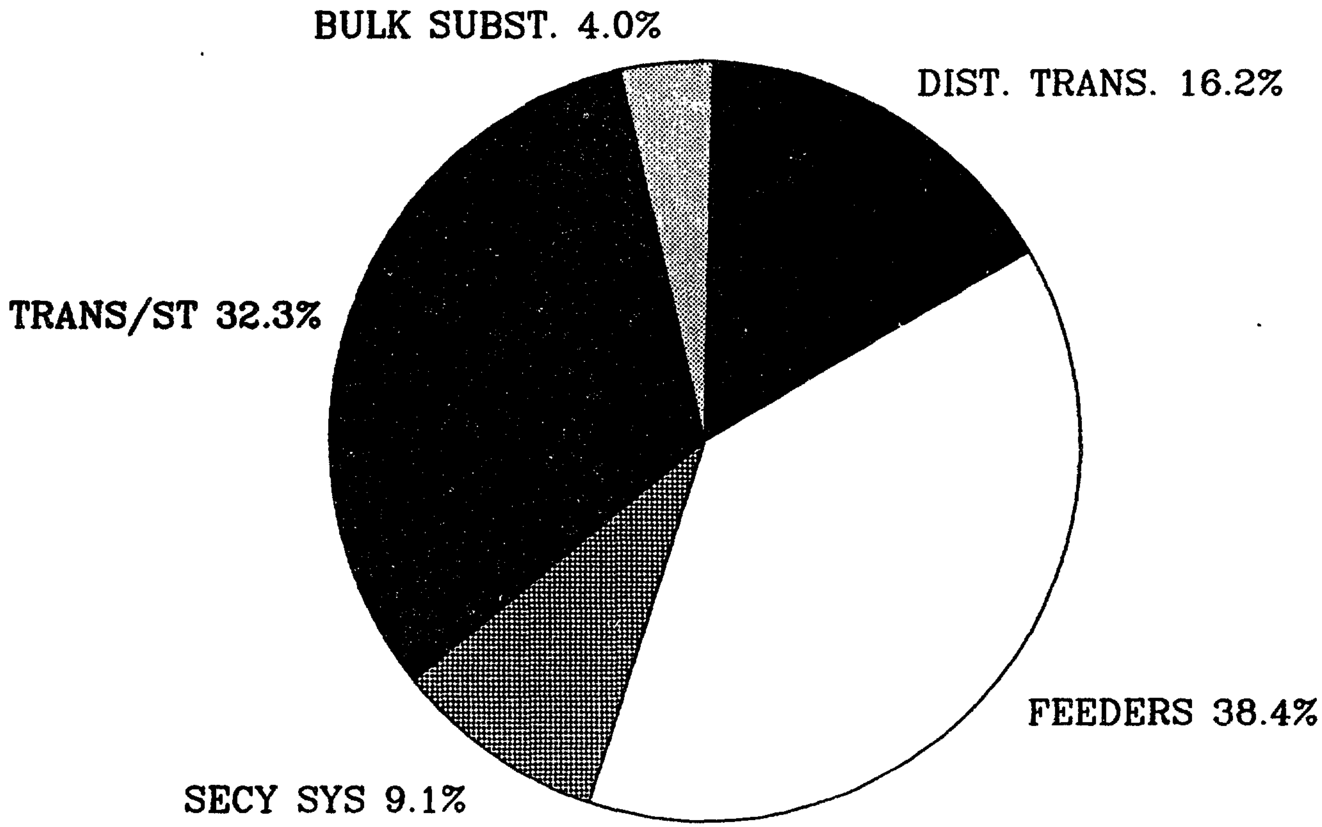
Distribution System Efficiency Program

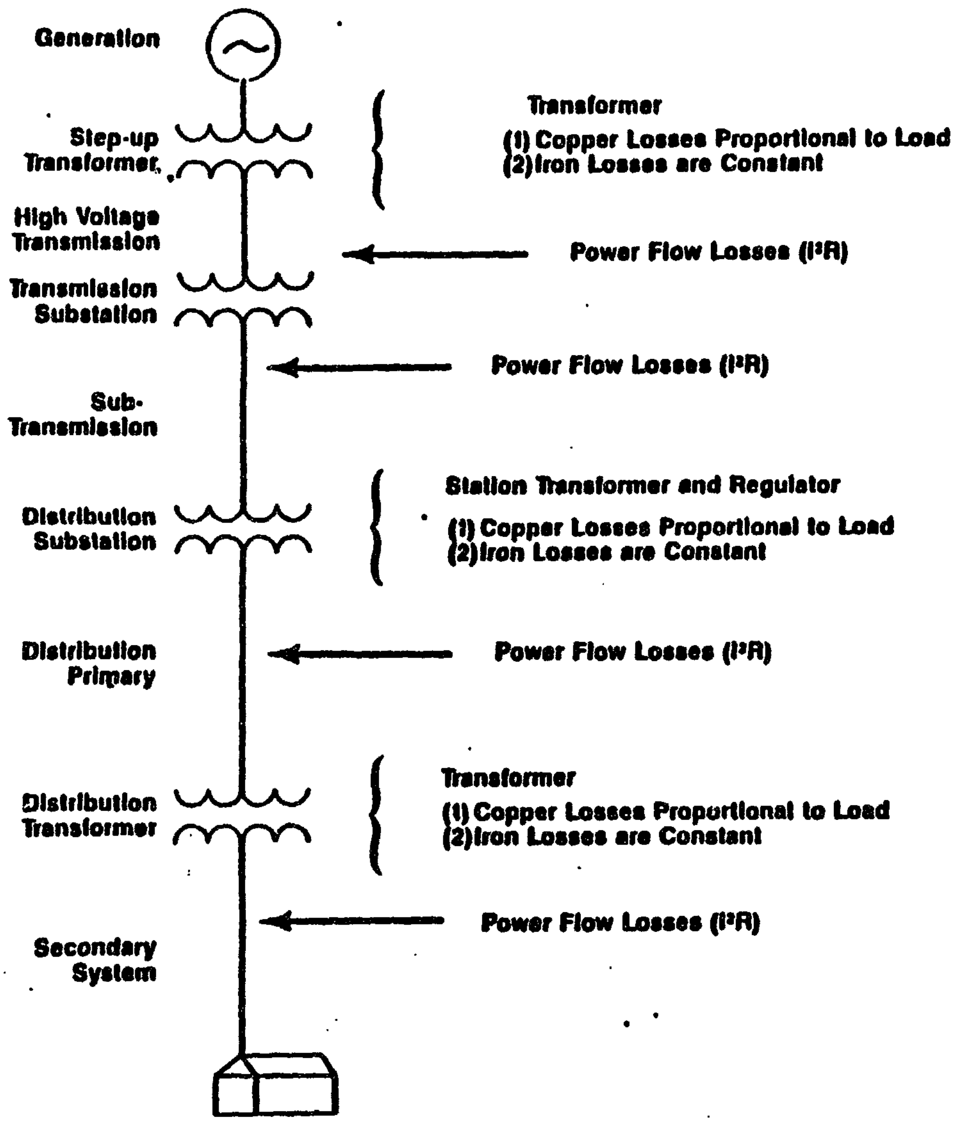


NON-GENERATING PUBLIC UTILITIES LOSSES



INVESTOR OWNED UTILITIES LOSSES




Generation
Step-up Transformer
Transformer
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
High Voltage Transmission
Power Flow Losses (I²R)
Transmission Substation
Power Flow Losses (I²R)
Sub-Transmission
Distribution Substation
Station Transformer and Regulator
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
Distribution Primary
Power Flow Losses (I²R)
Distribution Transformer
Transformer
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
Secondary System
Power Flow Losses (I²R)

REGION'S T&D COMPONENTS

- 1.3 million distribution transformers (under 7.5 kVA to over 500 kVA)
- 1,200 substation transformers (1.0 MVA to over 60 MVA)
- 60,000 circuit miles of primary feeder (normal voltages from 11 kV to 33 kV)
- 24,000 circuit miles of nonfederal transmission lines (operating voltages of 34.5 kV to 230 kV.)

FEEDER LOSS FORMULA

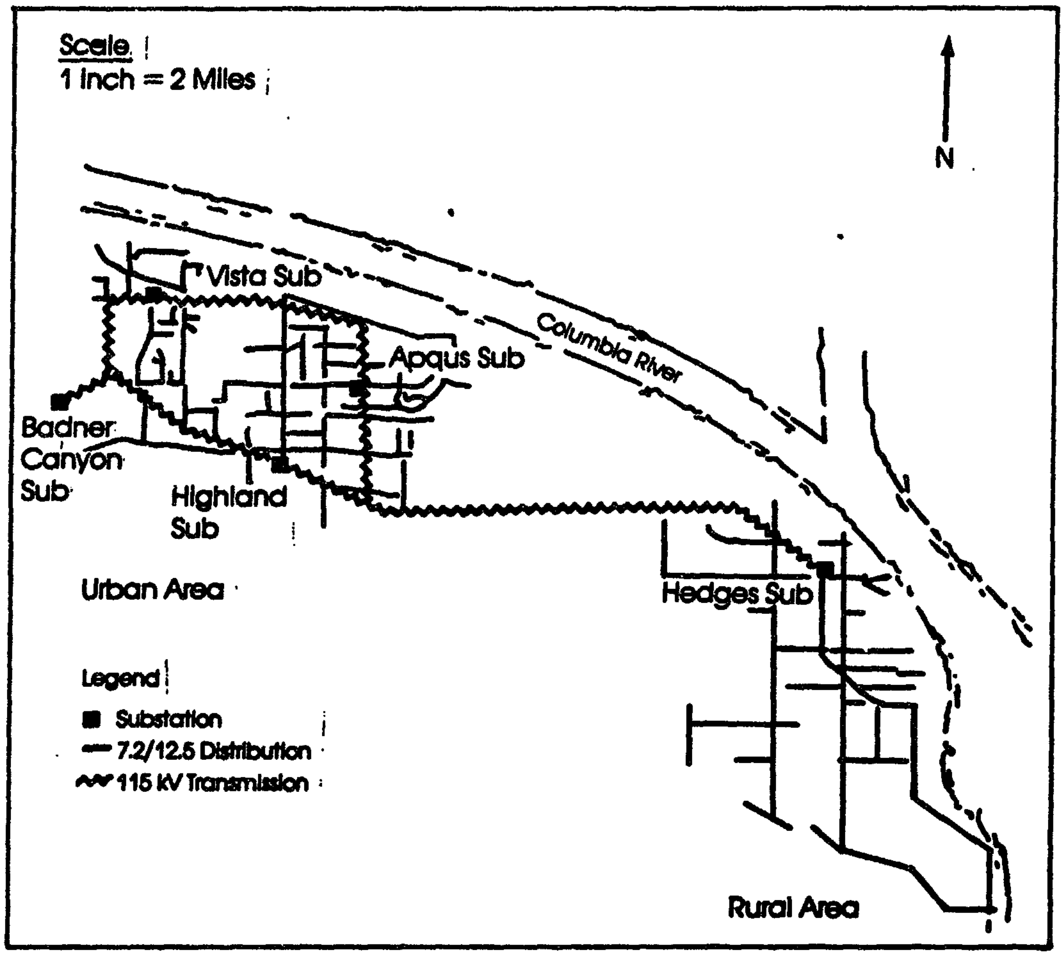
Feeder Loss Formula

$$\text{kWh loss} = \frac{(\text{Peak kW})^2(\text{Resistance per phase per mile})(\text{Loss factor})(8760)}{(\text{kV})^2(\text{Power factor})^2(\text{Number of phase})(1000)}$$

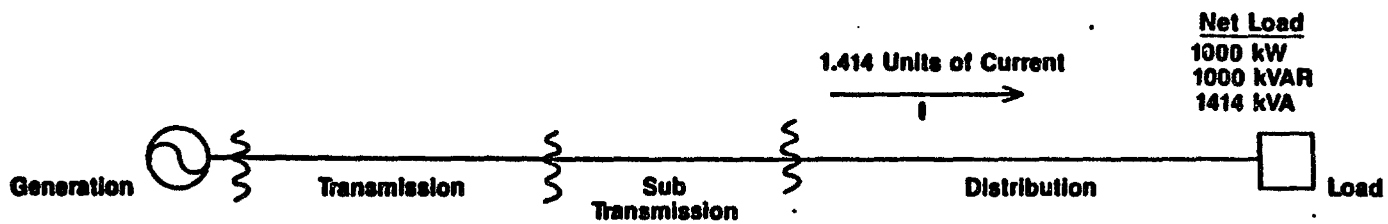
SYSTEM IMPROVEMENT ALTERNATIVES

1. Reconfiguration
2. Add Shunt Capacitance
3. Reconductoring
4. Replace Distribution Transformers
5. Raise Voltage
6. Add Parallel Feeder
7. Add or Balance Phases

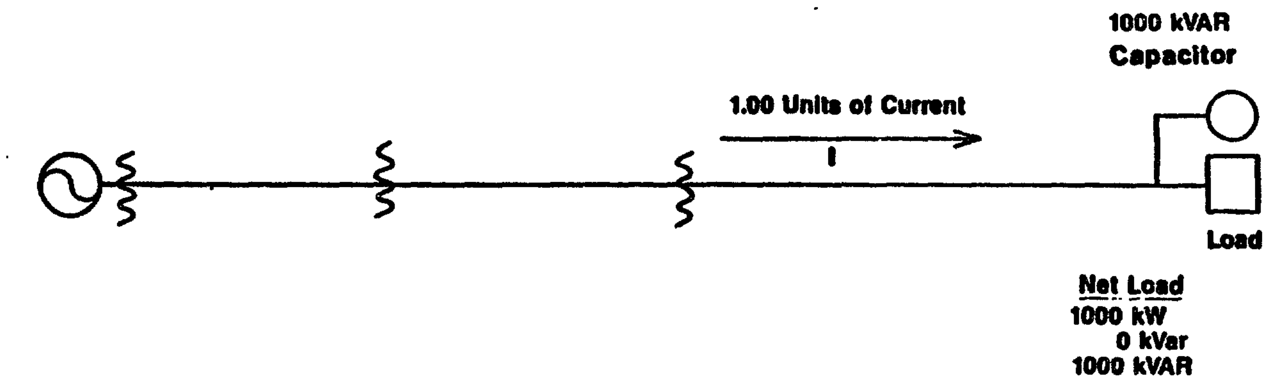
Sample System



POWER FACTOR CORRECTION



(A) No Power Factor Correction

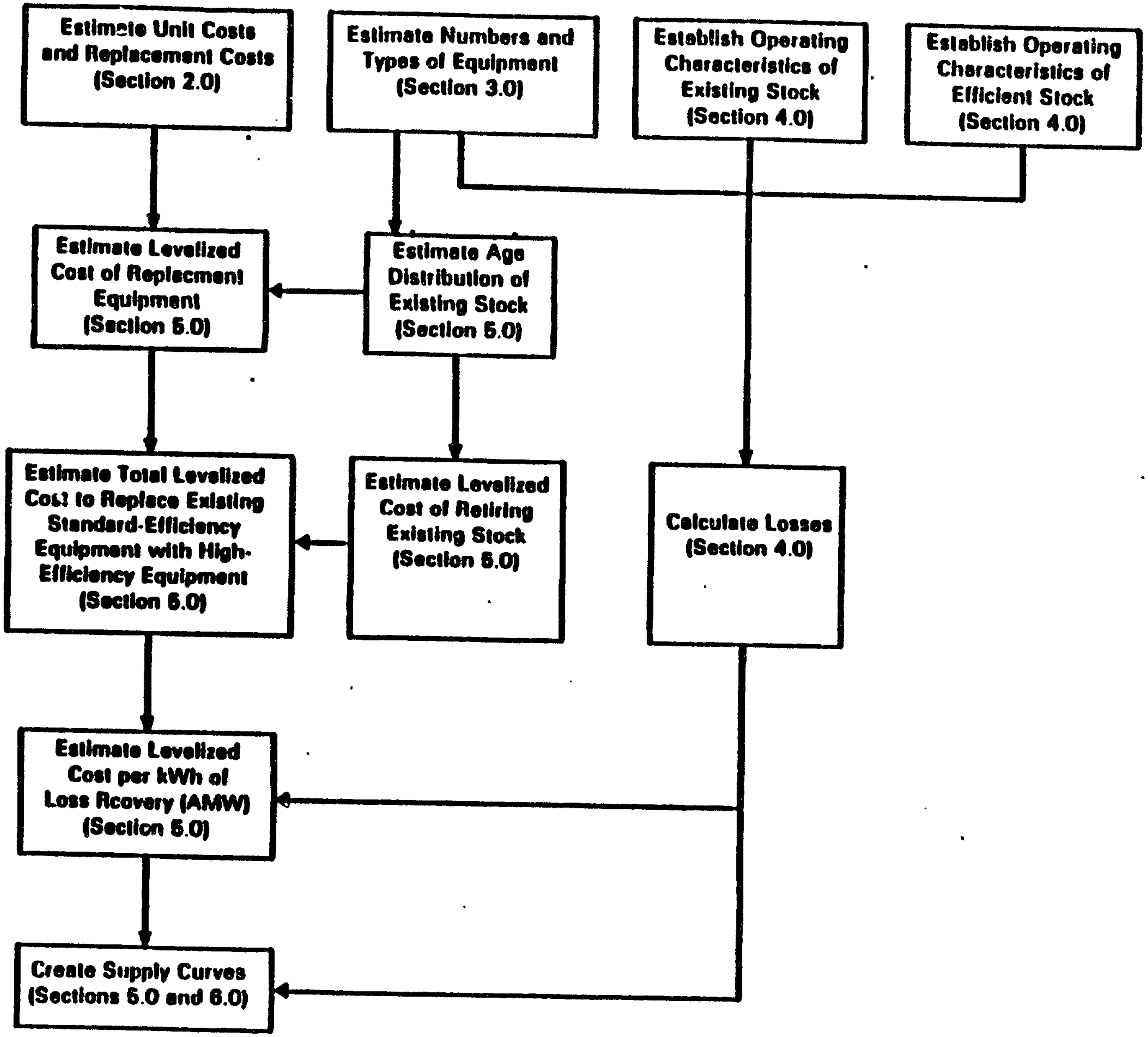


(B) With 100% Power Factor

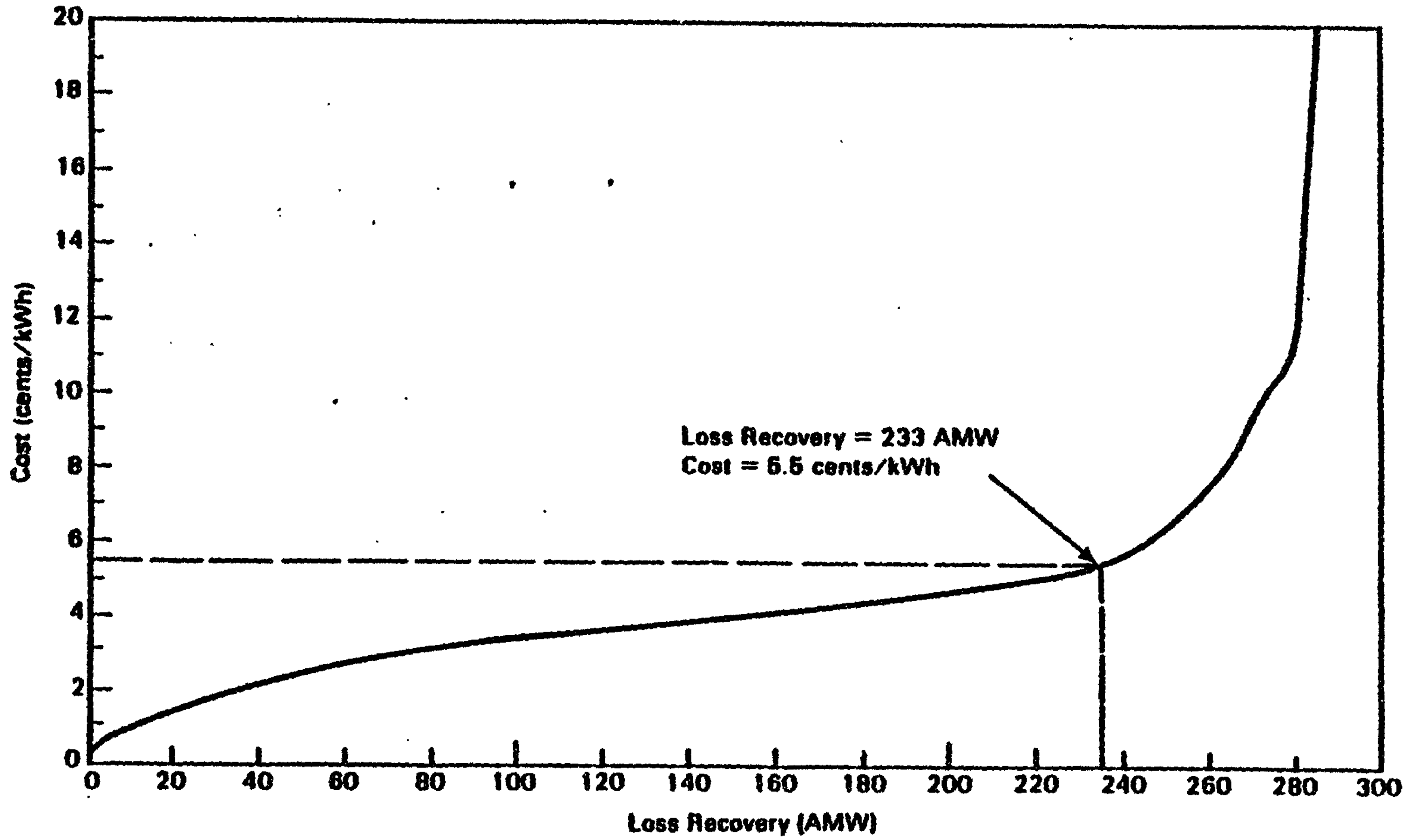
PENINSULA LIGHT CO. LOCKER ROAD FEEDER
MOST COST EFFECTIVE METHODS

METHOD	(MILL/KWH)
1. Reconfigure	-
2. Add Capacitors	18
3. Reconductor	50
4. Replace Transformers	66

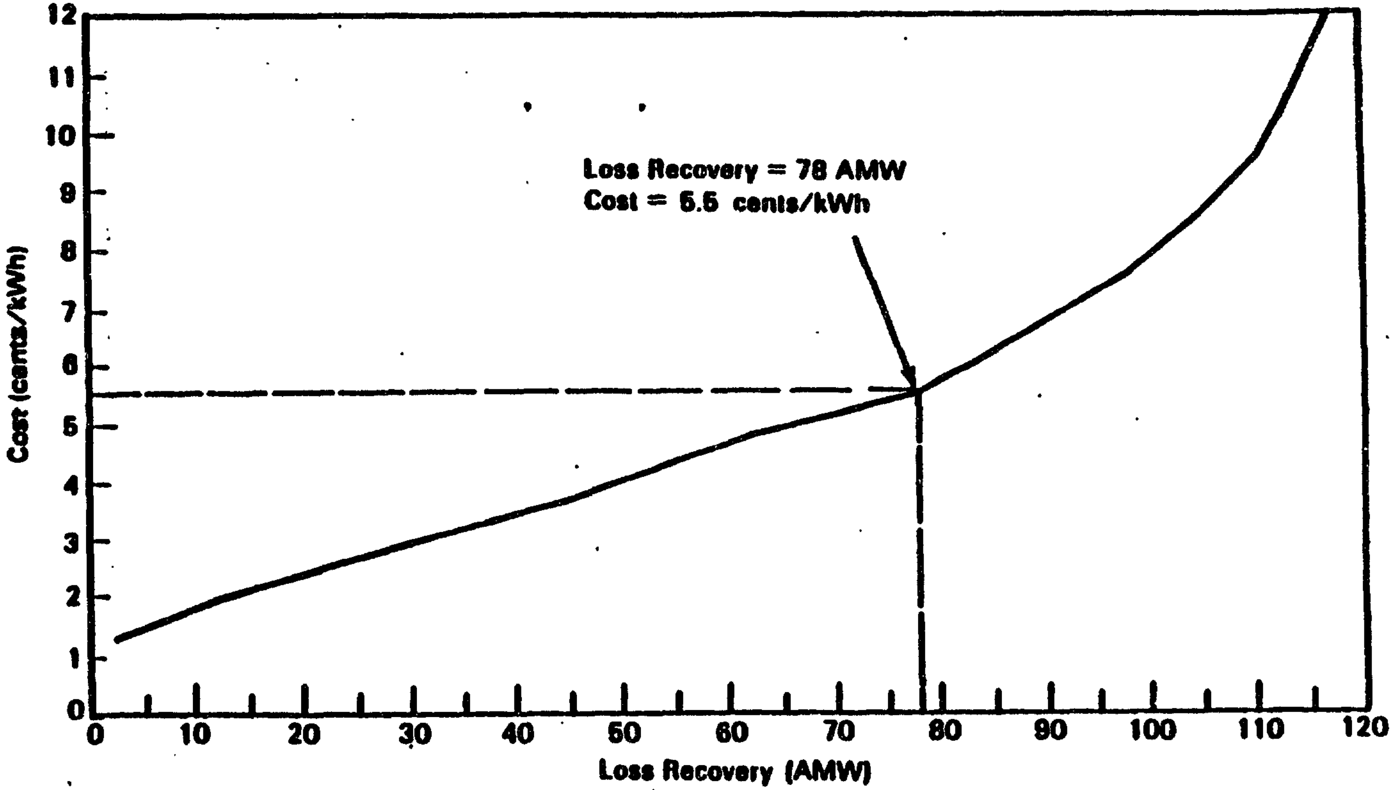
Supply Curve Methodology



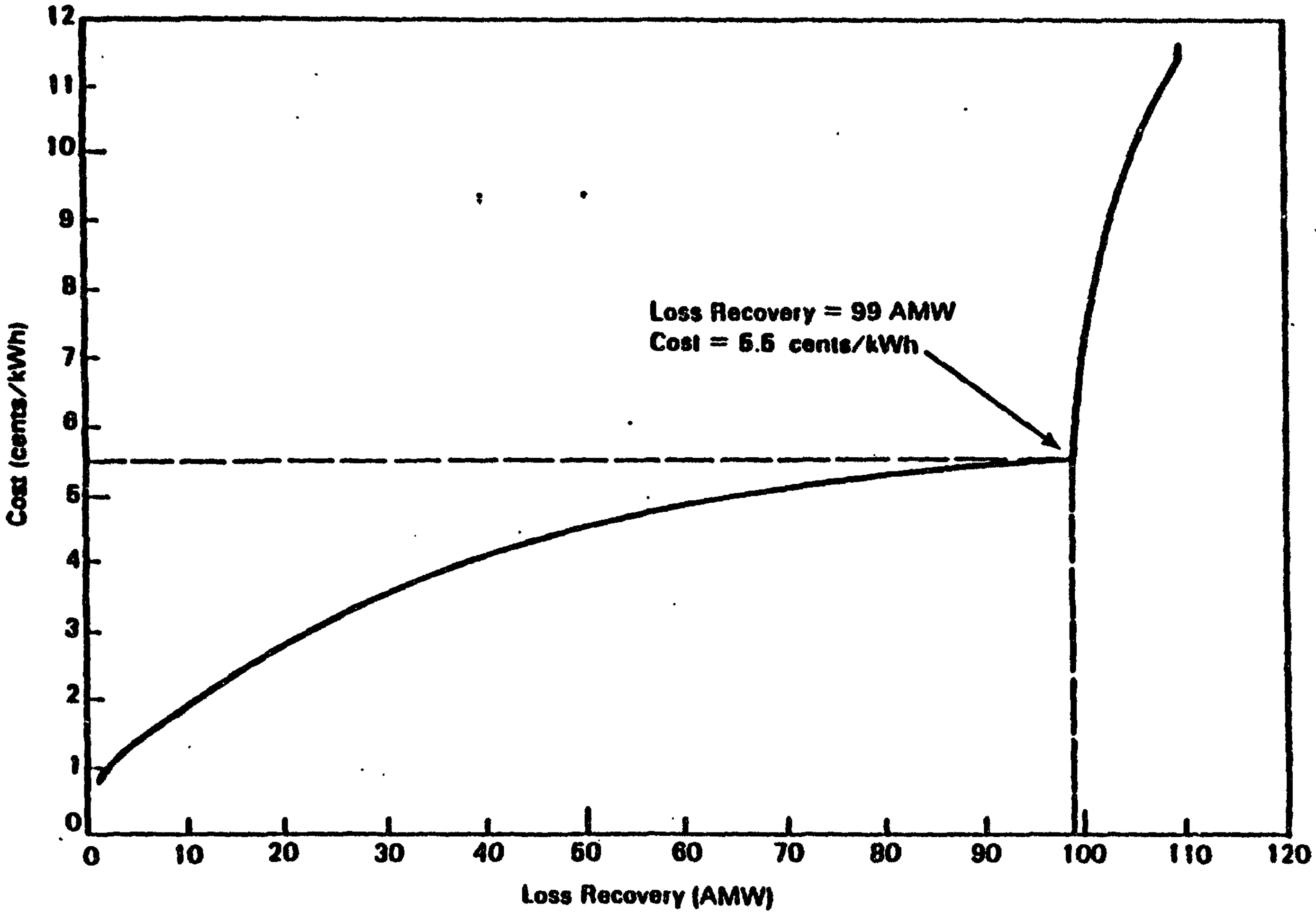
T & D System Supply Curve



Distribution Transformer Supply Curve



Reconductor Supply Curve



Distribution Voltage Upgrade

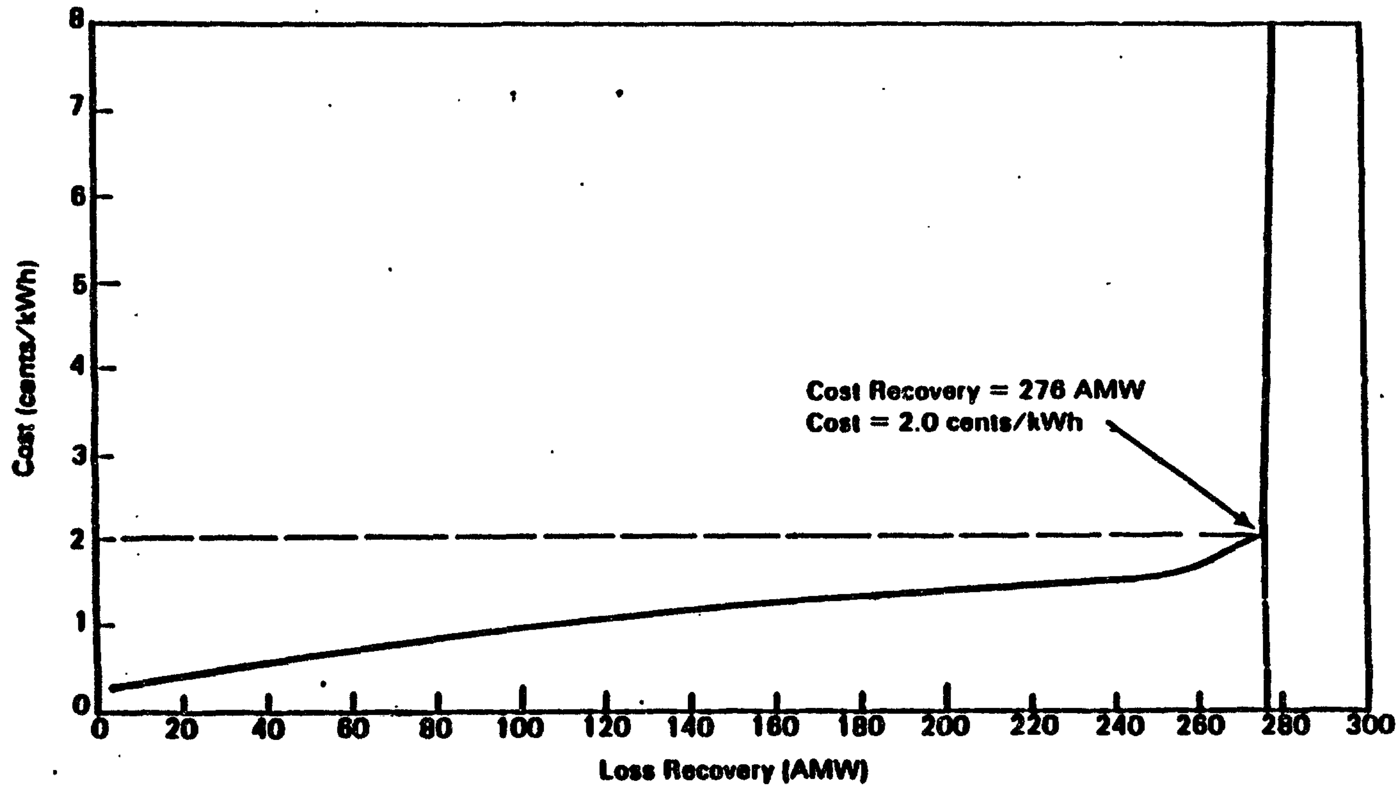
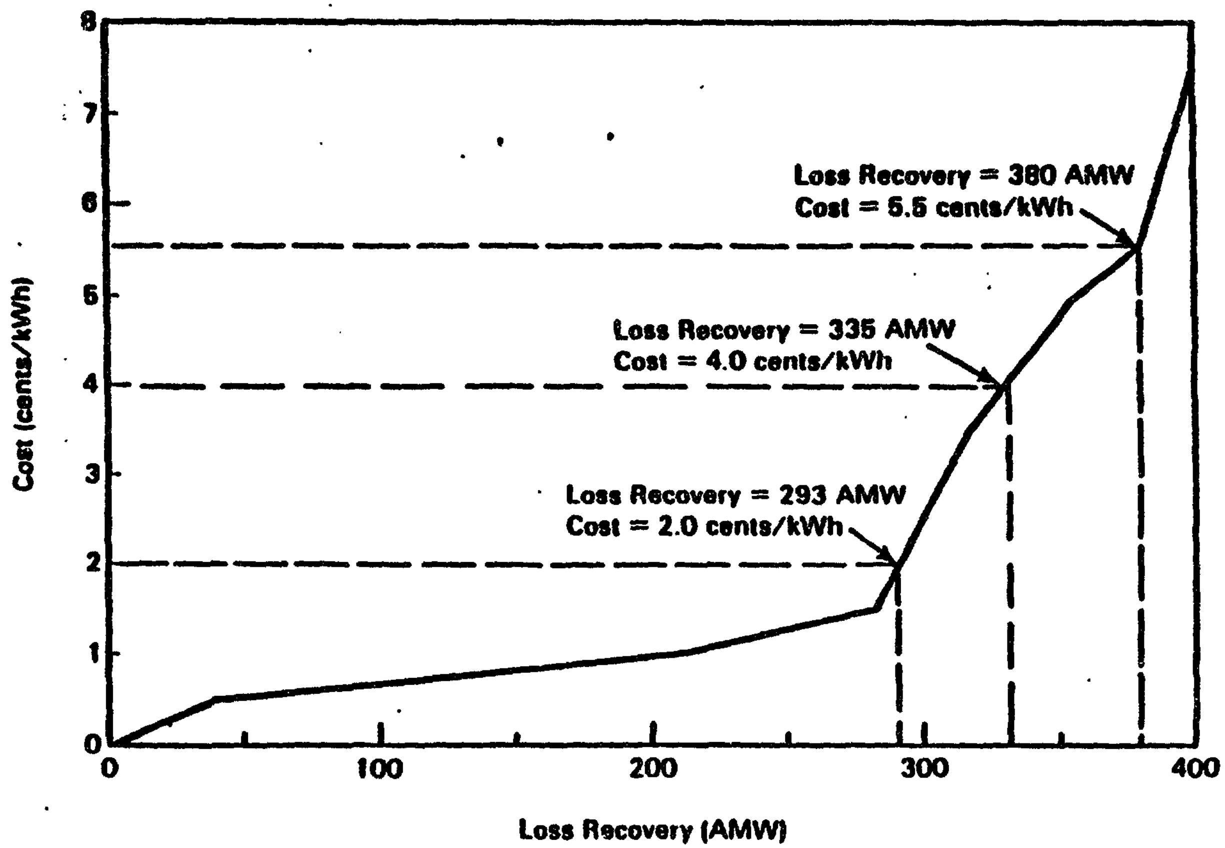
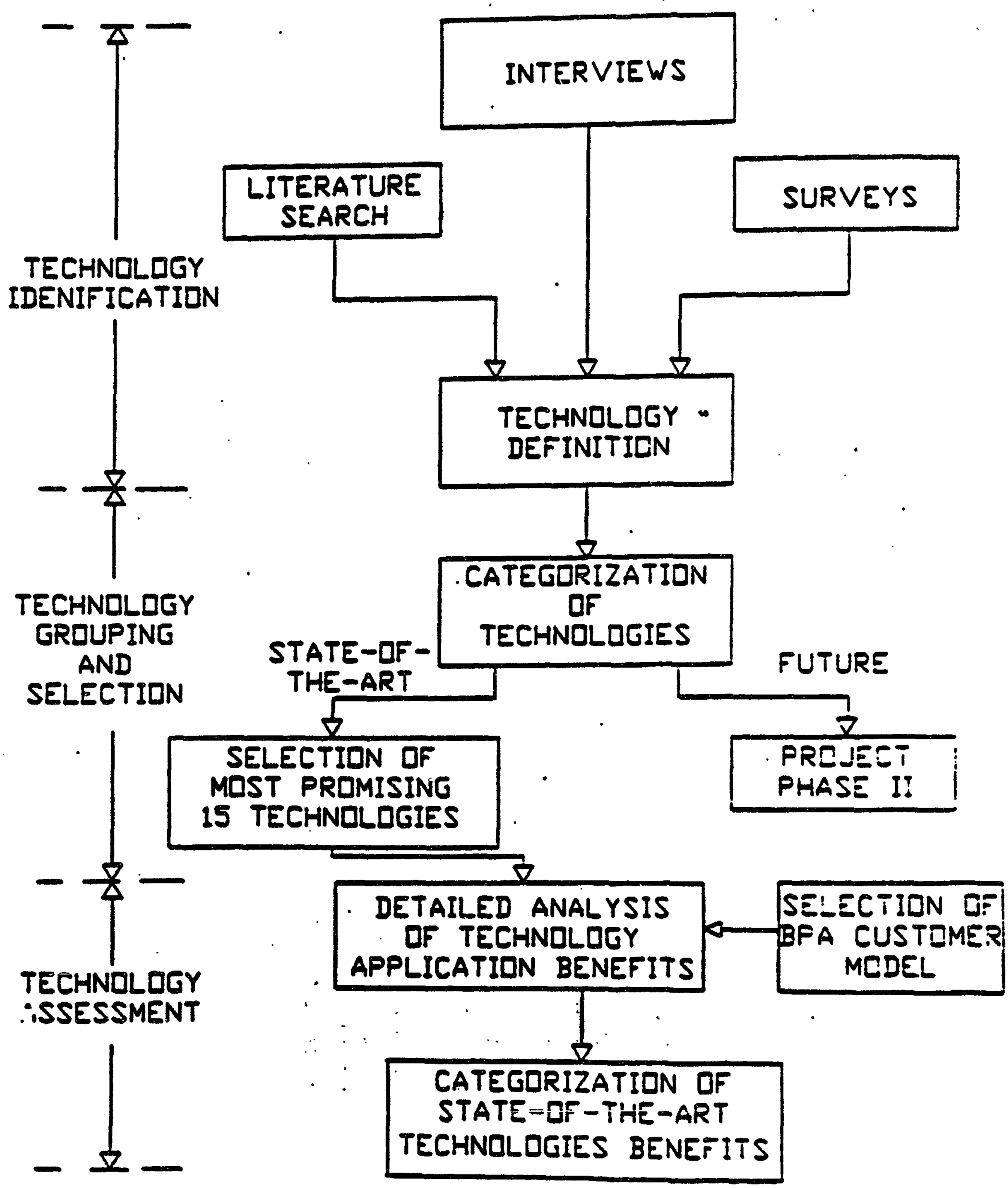


FIGURE 6.6. Supply Curve for Voltage Upgrade of the Existing 12.5 kV System to 34 kV

Composite Supply Curve



T & D, R & D Evaluation Method



STATE OF THE ART RANKING

TECHNOLOGY

1. IMPROVE VAR SITING
2. OPTIMUM FEEDER RECONFIGURING
3. DYNAMIC PHASE LOAD BALANCING
4. DISTRIBUTION AUJTOMATION
5. ANALYZE LOAD CONTROL/MANAGEMENT
6. DISTRIBUTION AUTOMATION/LOAD MANAGEMENT
7. AMORPHOUS STEEL TRANSFORMERS
8. IMPROVED SILICON STEEL DISTRIBUTION TRANSFORMERS
9. ALUMINUM CARBIDE CONDUCTOR
10. OPTIMAL COMPONENT COSTS FOR TRANSMISSION
11. STANDARD TO INCLUDE LOSSES
12. CONSERVATION VOLTAGE REDUCTION
13. IMPROVE DISTRIBUTION ANALYSIS/PLANNING
14. IMPROVED INSULATORS
15. IMPROVED FUSES

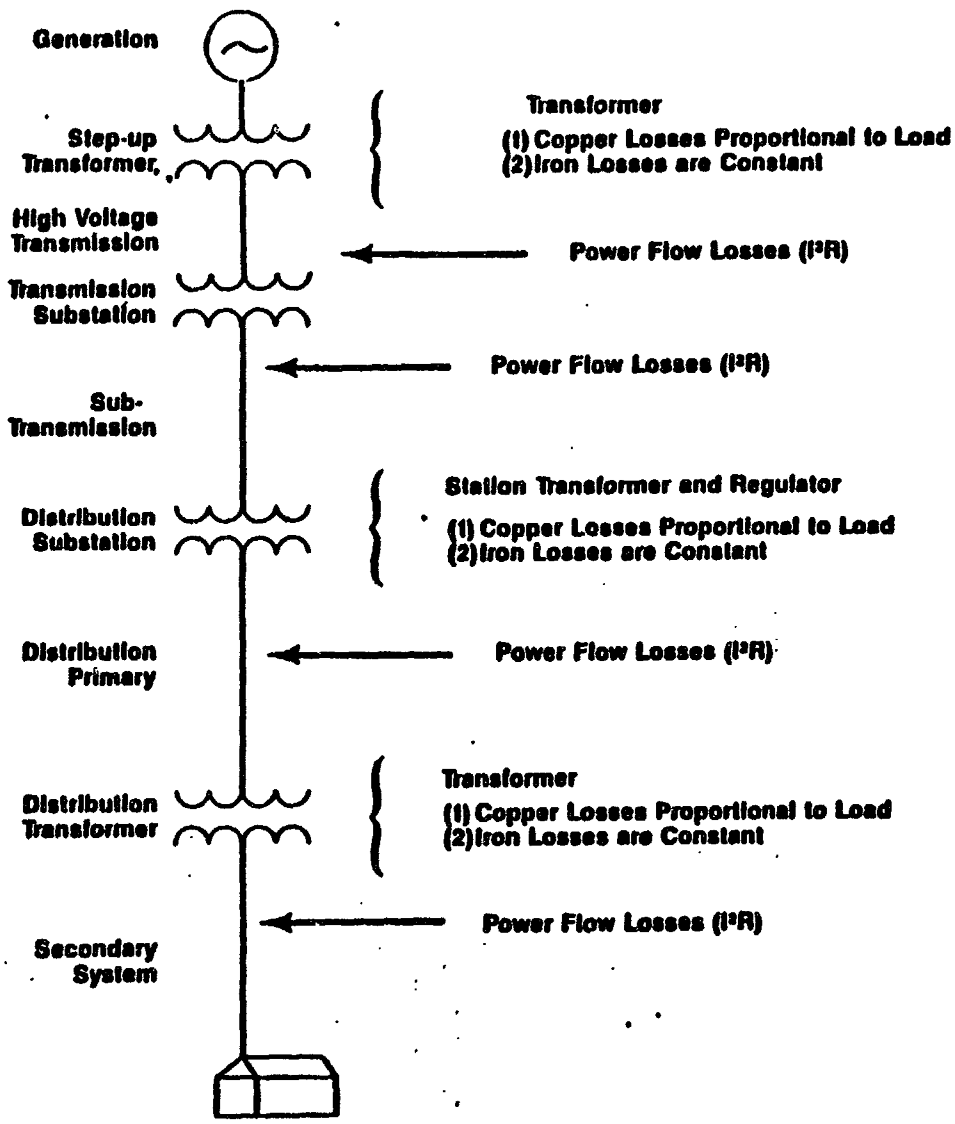
TOP STATE-OF-ART TECHNOLOGIES

1. DEMAND SIDE MANAGEMENT
2. AMORPHOUS STEEL DISTRIBUTION TRANSFORMERS
3. CONSERVATION VOLTAGE REDUCTION
4. DISTRIBUTION AUTOMATION
5. SUPERCONDUCTIVITY

WHAT ARE DEMAND-SIDE ACTIVITIES

- o Defined as any means by which a utility modifies its customers' load shapes either directly or indirectoly

- o Includes:
  - Load management
  - Conservation
  - Electrification
  - Load growth


Generation
Step-up Transformer
High Voltage Transmission
Transmission Substation
Sub-Transmission
Distribution Substation
Distribution Primary
Distribution Transformer
Secondary System
Transformer
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
Power Flow Losses (I²R)
Power Flow Losses (I²R)
Station Transformer and Regulator
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
Power Flow Losses (I²R)
Transformer
(1) Copper Losses Proportional to Load
(2) Iron Losses are Constant
Power Flow Losses (I²R)

A Method for Evaluating the General Load and Loss Effects of Demand-Side Management on the T&D Delivery System

C.L. BROOKS
WESTINGHOUSE ELECTRIC
CORPORATION
SENIOR MEMBER

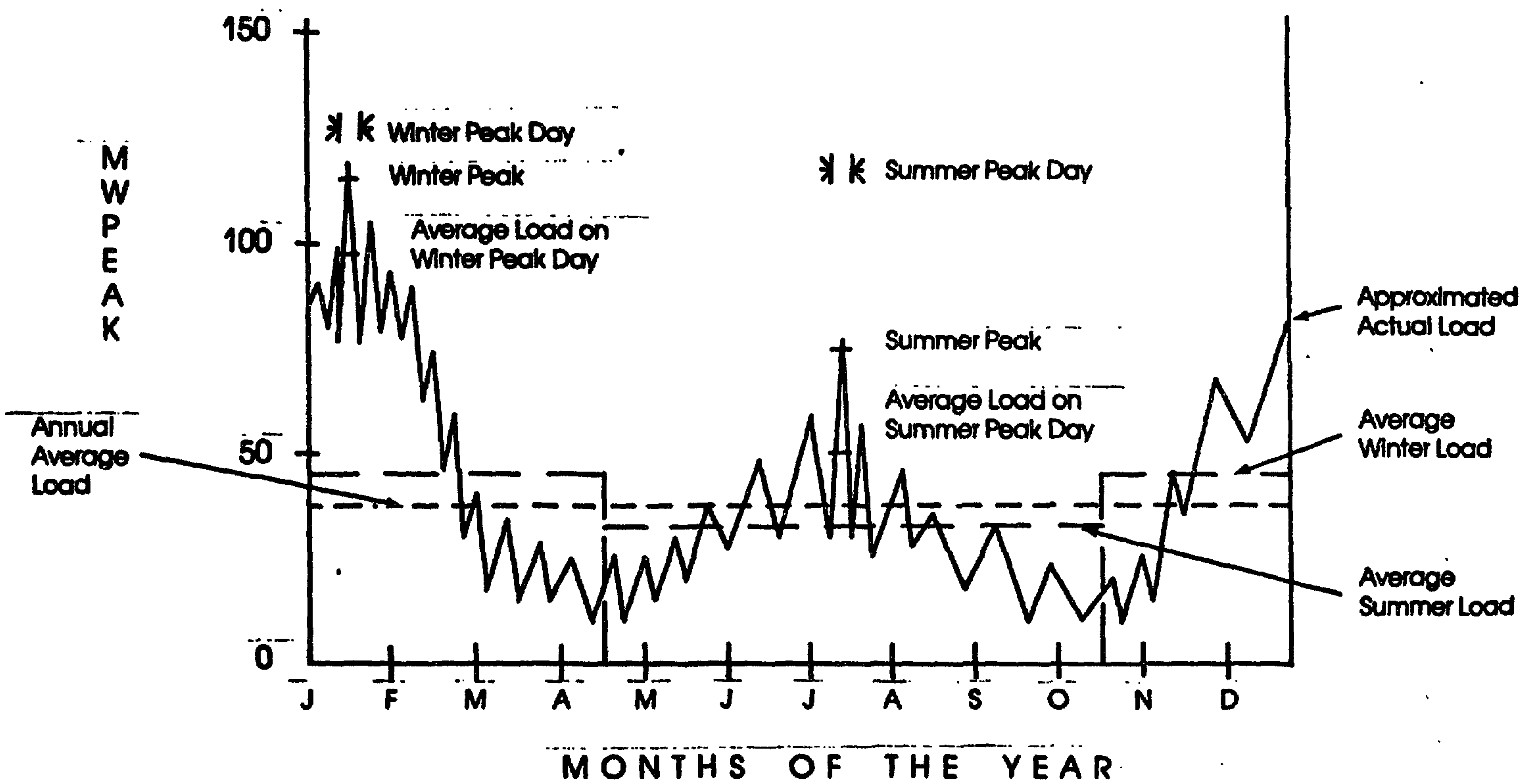
B.W. KENNEDY
BONNEVILLE POWER
ADMINISTRATION
MEMBER

J.W. SANDERS
BENTON COUNTY (WA)
PUD NO. 1

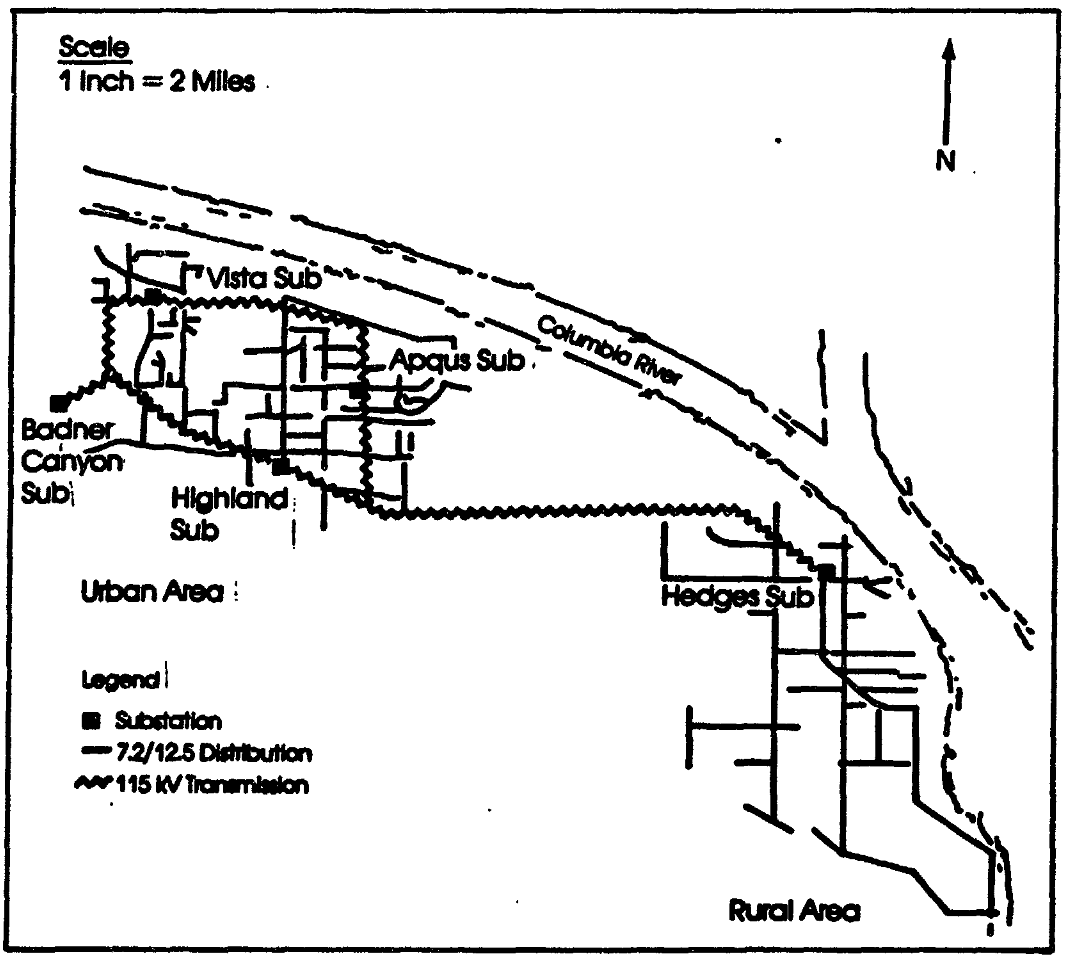
Application of Method

- o BENTON COUNTY P.U.D. NO. 1 IN STATE OF WASHINGTON
- o SYSTEM MODEL
  - 3 URBAN AND 1 RURAL SUB
  - ABOUT 150 MW
  - LOAD DATA FOR ALL DISTR. TRANS.
  - LOAD FLOW
    : 500 NODES
    : FIXED IMPENDANCE LOAD
    : 3-PHASE UNBALANCED
  - FOUR SUBPROFILES
    : DIVIDED BY RURAL AND URBAN AREAS
    : DIVIDED BY 6-MONTH WINTER AND SUMMER SEASONS

Load Characteristics



Sample System



Objective of sample application -

DETERMINE THE IMPACT ON THE SYSTEM LOAD AND LOSSES, IF THE PEAK DEMAND WAS RESTRICTED TO THE LOWEST POSSIBLE PEAK ON THE PEAK DAY WITH SAME ENERGY CONSUMPTION (UNITY LOAD FACTOR ON PEAK DAY)

Results

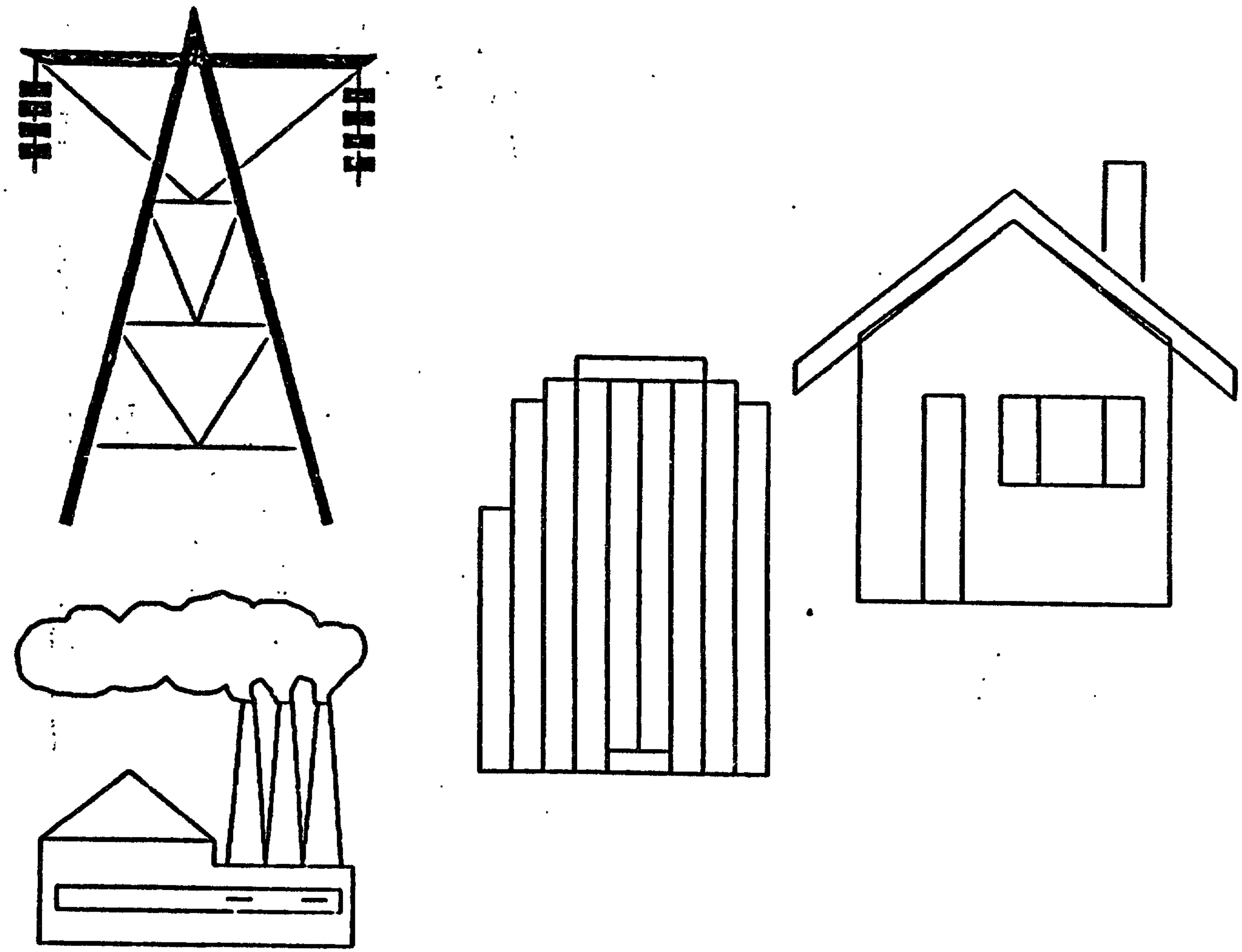
- o PEAK DROPPED
  128,429 KW TO 106,596 KW (17.0%)
- o WINTER URBAN LOAD FACTOR INCREASED
  0.414 TO .499 (20.5%)
- o PEAK LOSSES DROPPED
  6,887 KW TO 5,263 KW (23.5%)
- o ENERGY LOSSES DROPPED
  18,219 MWH TO 17,376 MWH (4.6%)

Benton County - high, short peaks

AMORPHOUS STEEL TRANSFORMERS

- RP 1290-1 AMORPHOUS STEEL FOR TRANSFORMERS
- RP 1529-1 AMORPHOUS STEEL CORE DISTRIBUTION TRANSFORMER

CONSERVATION VOLTAGE REDUCTION



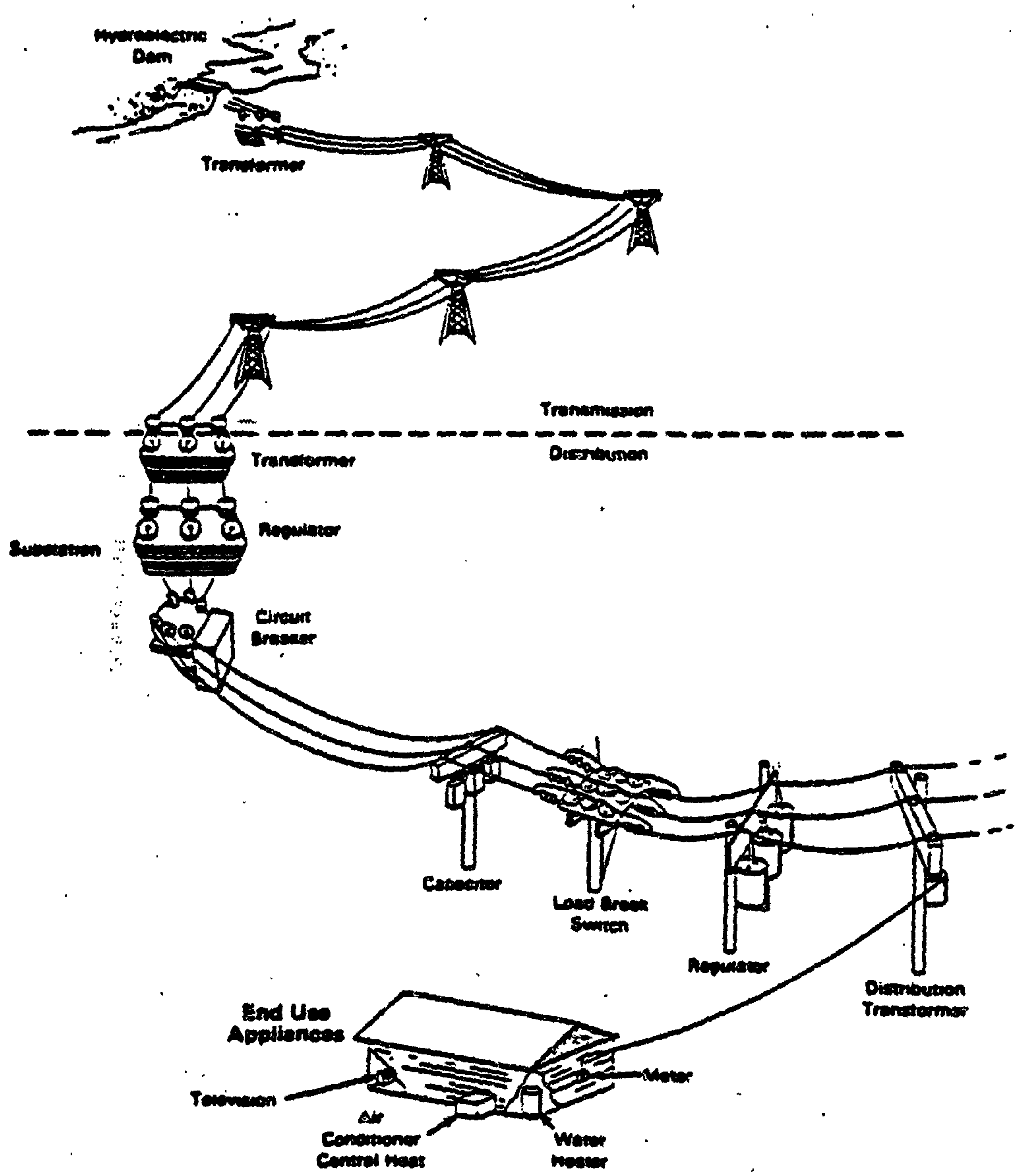
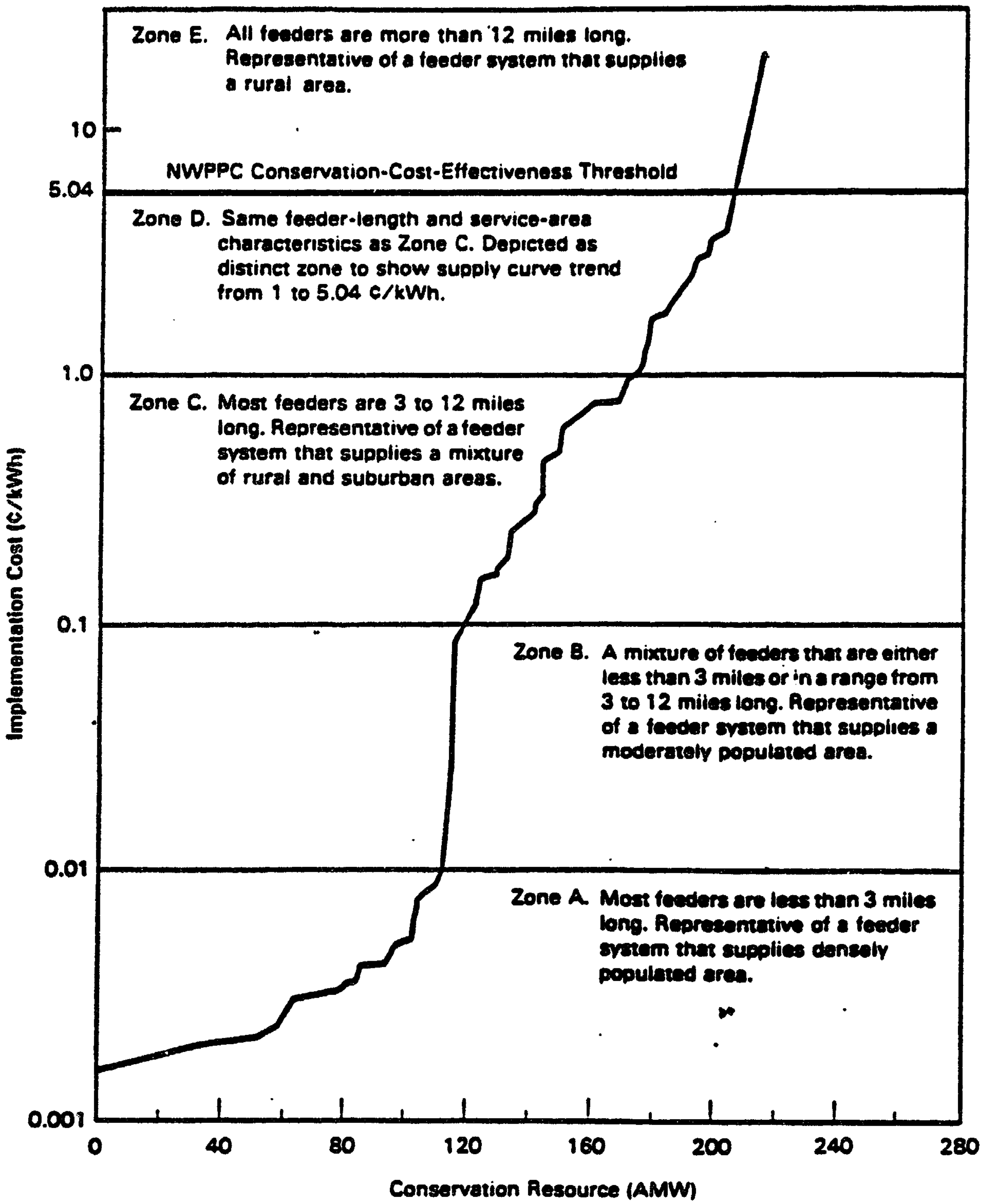


FIGURE 1.1. Representation of Northwest Electric T&D System

CVR Regional Supply Curve



DISTRIBUTION AUTOMATION

- o RP2021 ECONOMIC EVALUATION OF DISTRIBUTION AUTOMATION SYSTEMS
- o RP5689 DEMONSTRATION OF DISTRIBUTION AUTOMATION SYSTEM
- o RP1420 DEVELOPMENT AND TESTING OF MULTIPLE FUNCTION ELECTRONIC WATTHOUR METER
- o P850 DEMONSTRATION OF ALTERNATE COMMUNICATION SYSTEMS FOR DISTRIBUTION AUTOMATION
- o RP1535 BROADCAST RADIO SYSTEM FOR DISTRIBUTION AUTOMATION
- o RP1472 INTEGRATED CONTROL AND PROTECTION OF DISTRIBUTION SUBSTATIONS AND SYSTEM

SUPERCONDUCTIVITY OVERVIEW

1. WHAT IS SUPERCONDUCTIVITY?

2. WHY DO SOME MATERIALS BECOME SUPERCONDUCTING BELOW A CRITICAL TEMPERATURE?

3. APPLICATIONS AND LIMITATIONS OF CONVENTIONAL (METALLIC) SUPERCONDUCTORS.

4. THE NEW METAL-OXIDE SUPERCONDUCTORS:

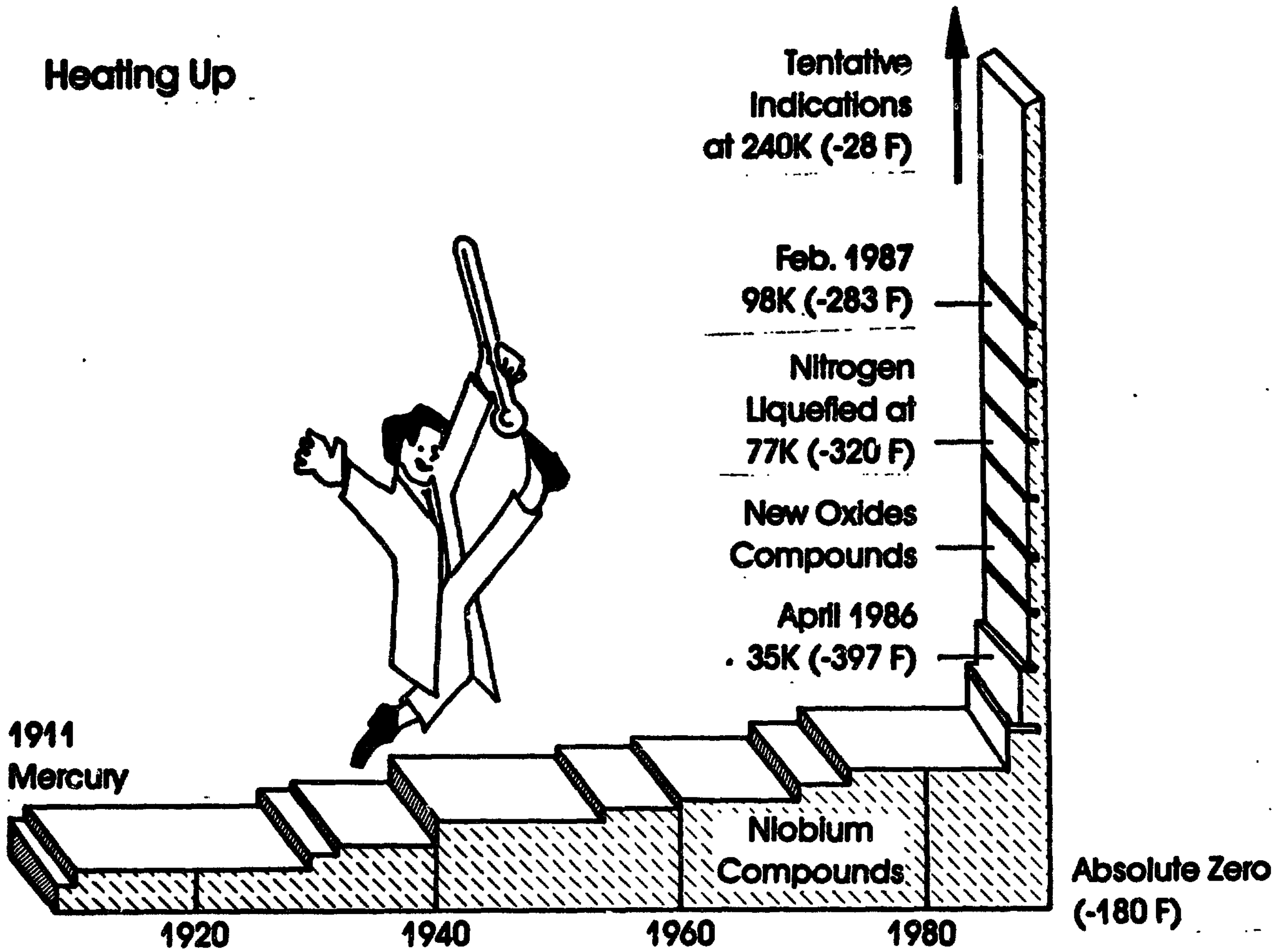
   a. STATE OF DEVELOPMENT/WHO IS INVOLVED
   b. CHALLENGES FOR R&D

1. WHAT IS SUPERCONDUCTIVITY?

CONVENTIONAL (METALLIC) SUPERCONDUCTORS ARE POOR CONDUCTORS AT ROOM TEMPERATURE. WHEN COOLED BELOW A CRITICAL TEMPERATURE, TWO REMARKABLE PROPERTIES APPEAR:

1. **Zero Electrical Resistivity**
2. **Expulsion of all magnetic flux (Meissner Effect)**

Heating Up


Tentative
Indications
at 240K (-28 F)
Feb. 1987
98K (-283 F)
Nitrogen
Liquefied at
77K (-320 F)
New Oxides
Compounds
April 1986
35K (-397 F)
1911
Mercury
Niobium
Compounds
Absolute Zero
(-180 F)
1920
1940
1960
1980

Transformer Loss Formula

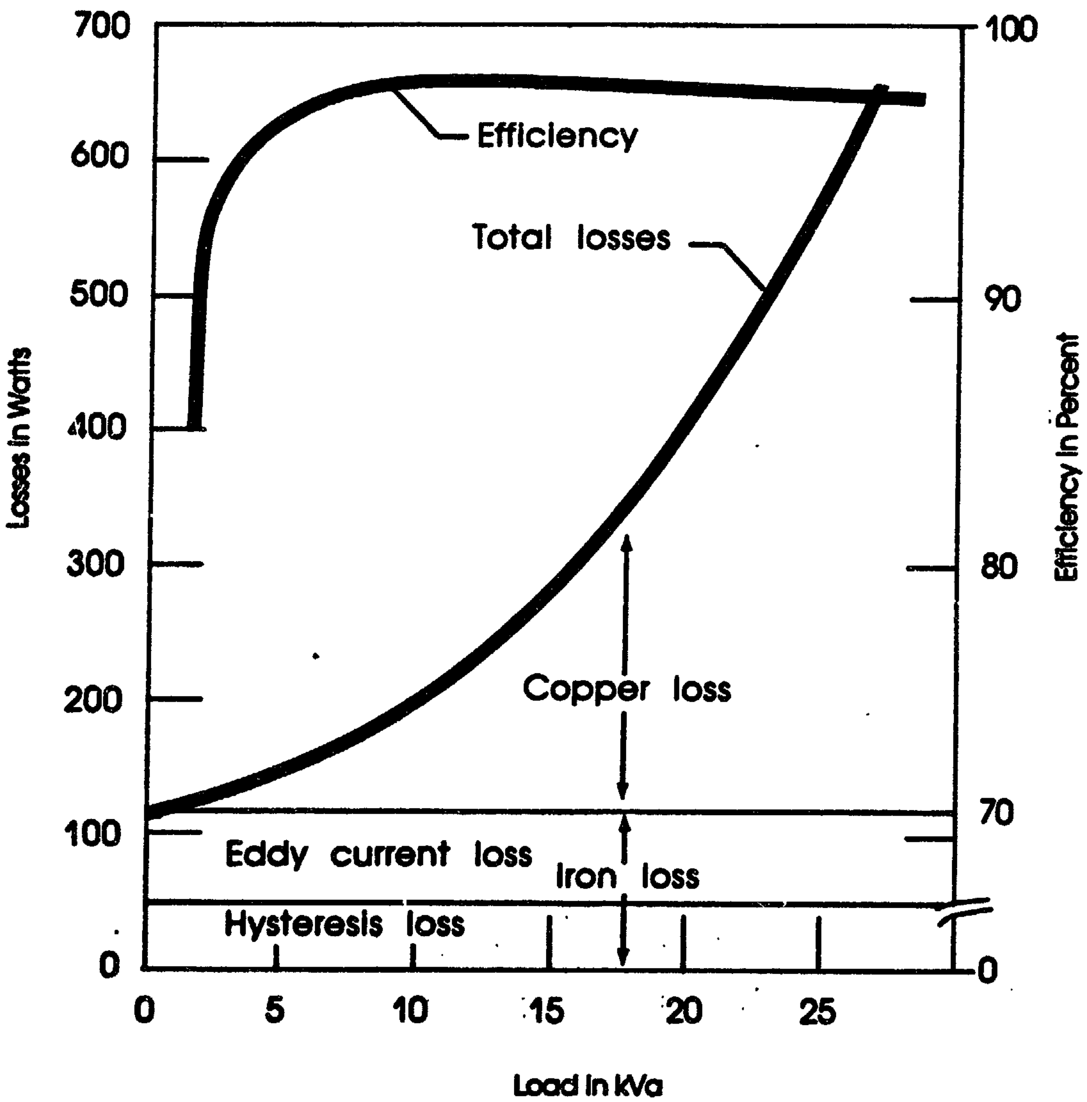
$$E = \frac{A-(NLL + LL)}{A} \times 100$$

WHERE E = EFFICIENCY OF UNIT (%)

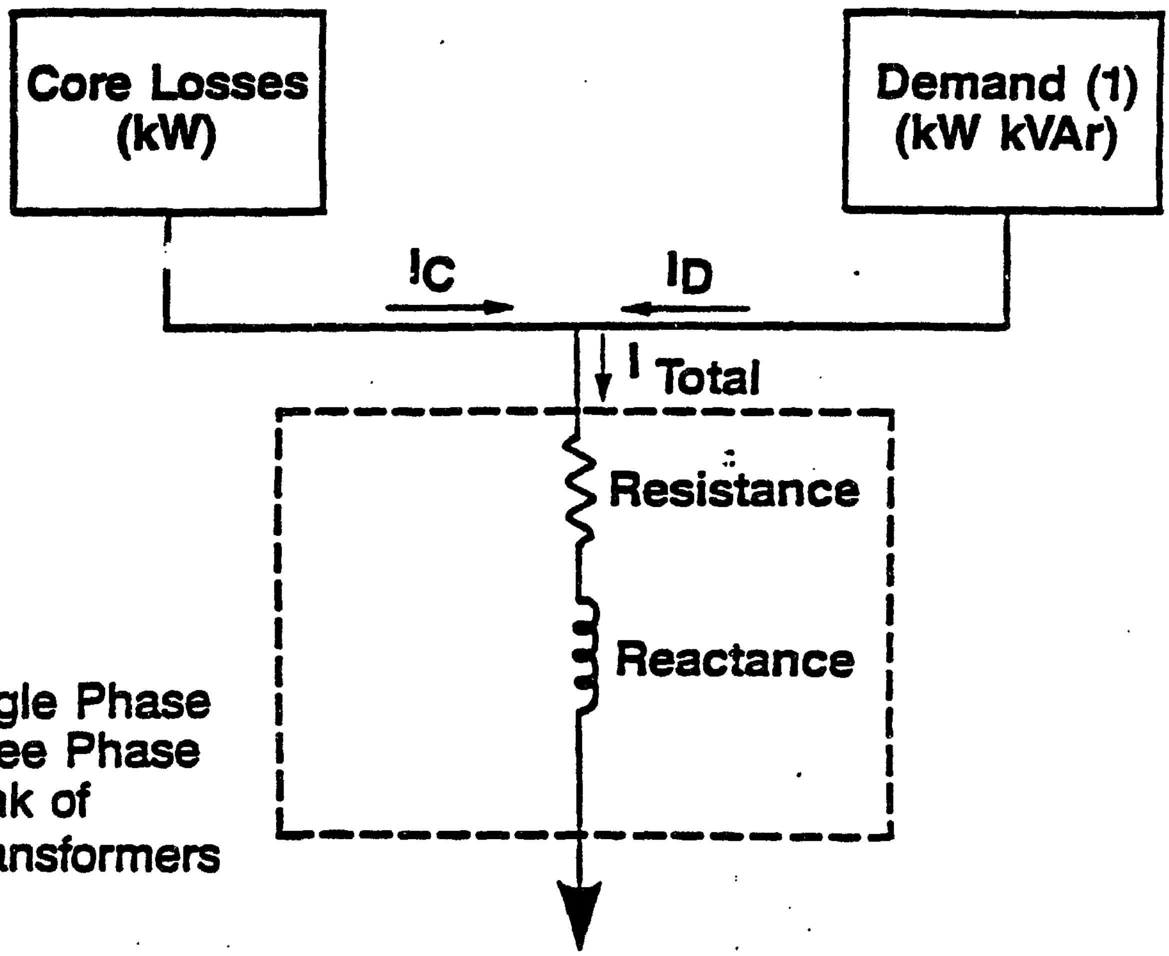
A = INSTALLED NAMEPLATE CAPACITY OF UNIT (KVA)

NLL = NAMEPLATE NO-LOAD LOSS OF UNIT (KW)

LL = NAMEPLATE LOAD LOSS OF UNIT (KW)


700
600
500
400
300
200
100
0
Losses in Watts
100
90
80
70
0
Efficiency in Percent
Efficiency
Total losses
Copper loss
Eddy current loss
Iron loss
Hysteresis loss
0
5
10
15
20
25
Load in kVa

BASIC TRANSFORMER MODEL



Model
- Single Phase
- Three Phase
- Bank of Transformers

Demand Losses (kW)
Energy Losses (kWH)
Probable Loss of Life (%)

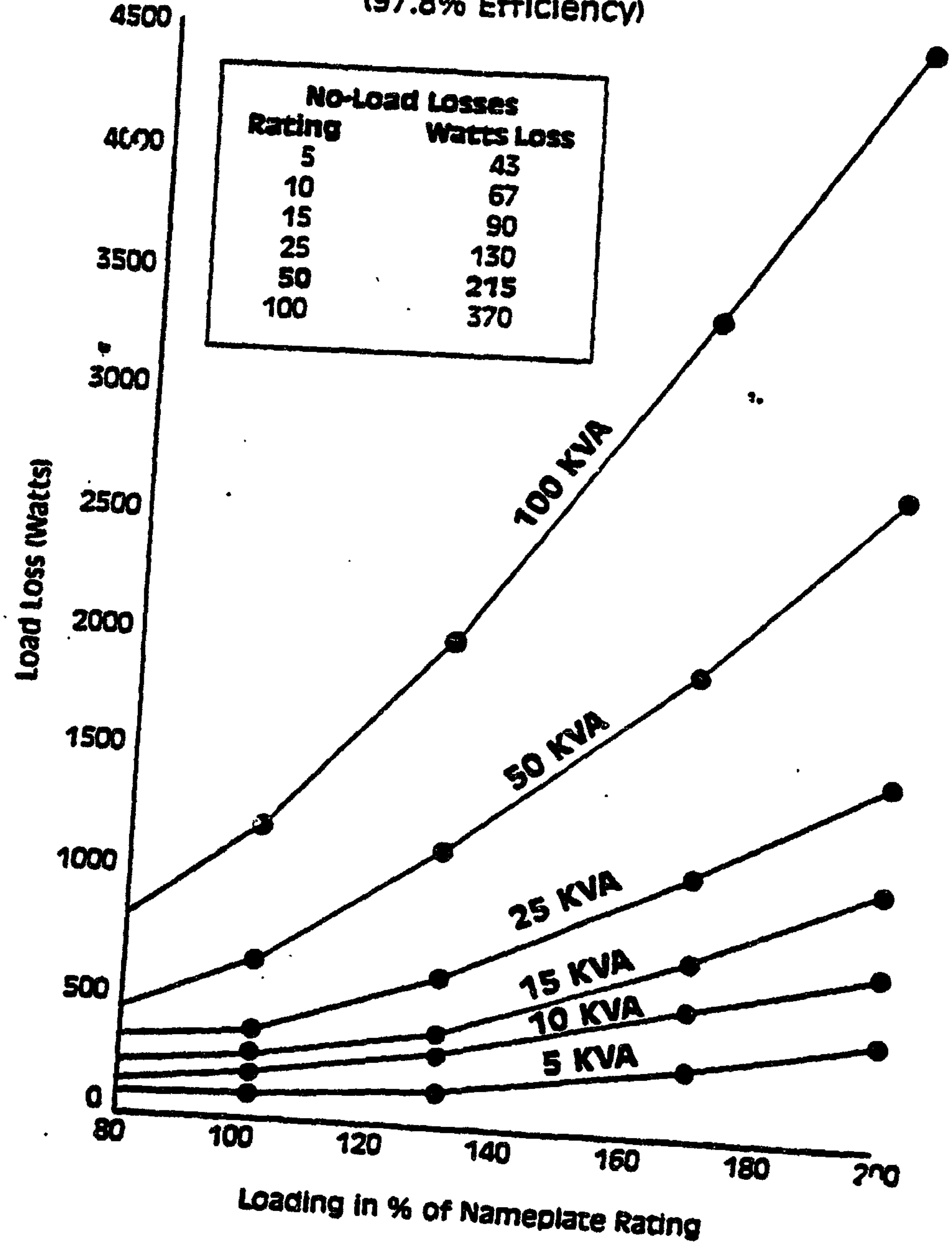
(1) Demand may be:
Single phase
Three phase
Mixed single and three phase

ANNUAL TRANSFORMER LOSSES
FOR A 5000 MW UTILITY

	MILLIONS OF KWHR	
TRANSFORMER TYPE	IRON	COPPER
GENERATOR STEP-UP	18	8
BULK POWER SUBSTATION	67	138
DISTRIBUTION SUBSTATION	97	114
DISTRIBUTION	328	127
TOTAL	510*	468

* 1.4% of Electricity Generated.

Figure 3a
Transformer Losses
Standard Transformers
(97.8% Efficiency)



Page 44

Figure 3b
Transformer Losses
High-Efficiency Transformers
(98.4% Efficiency)

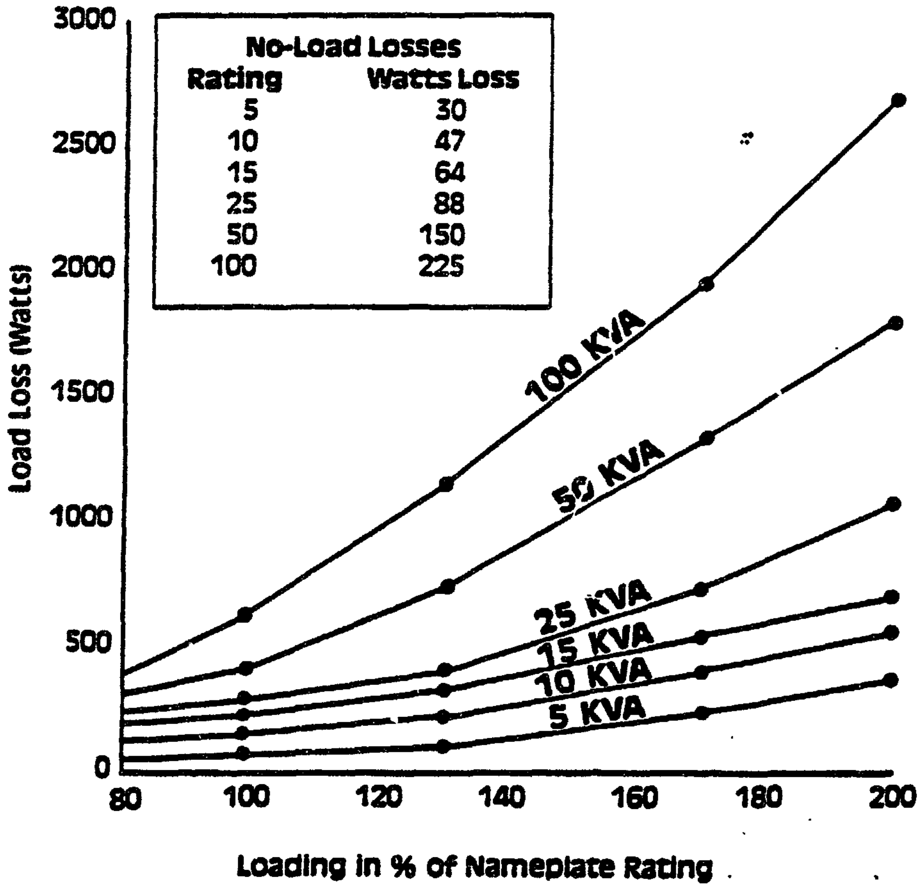
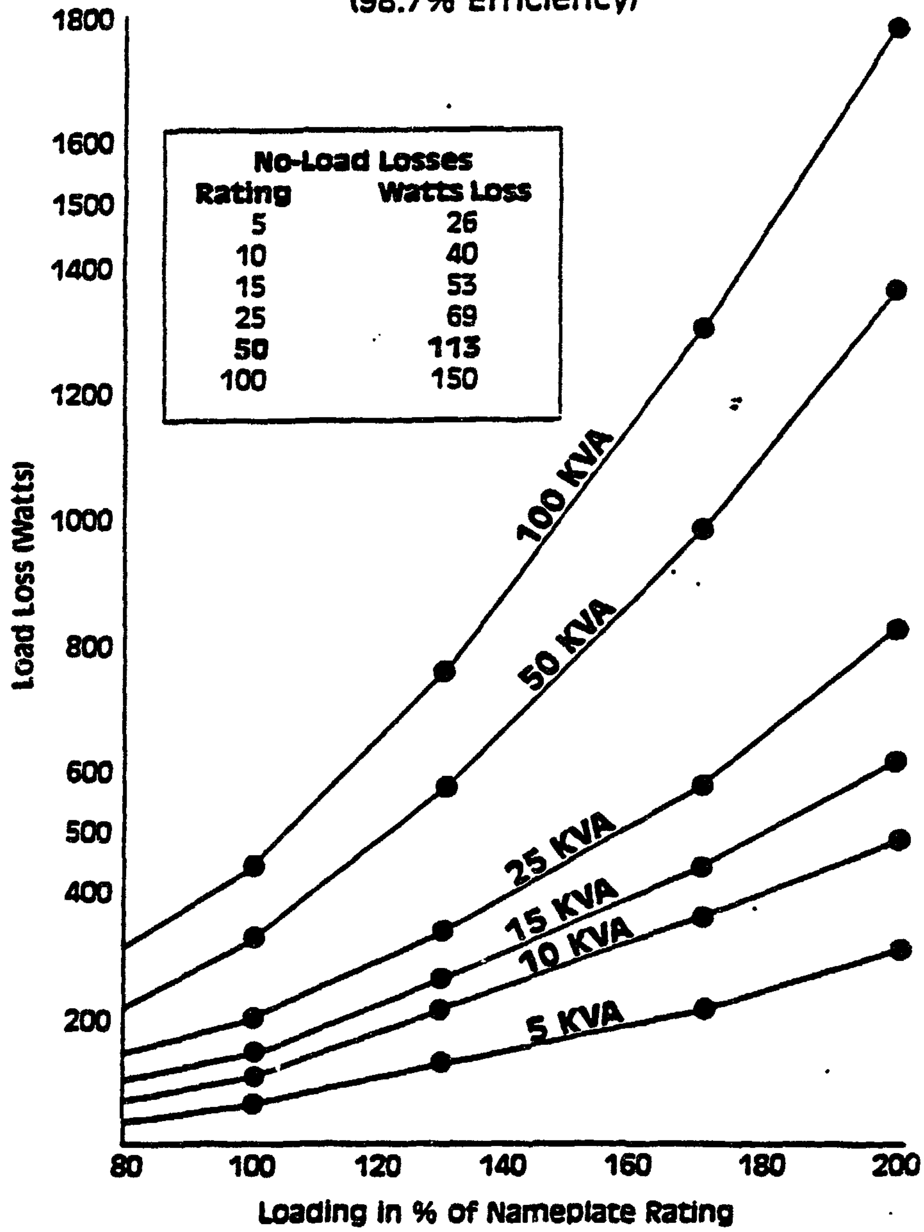


Figure 3c
Transformer Losses
Very High-Efficiency Transformers
(98.7% Efficiency)



	Core	
	Conventional	Amorphorous
COST OF LOSSES		
NO-LOAD LOSSES	48 WATTS X $5 WATT $240	18 WATTS X $5 WATT $ 90
LOAD LOSSES	284 WATTS X $1 $284	249 WATTS X $1 $249
TOTAL LOSSES	$524	$339
PURCHASE PRICE	$510	$695
TOTAL OWNING COST	$1034	$1034

ENGINEERING ECONOMICS OF LOSS REDUCTION PROJECTS

By

Mr. Barry Kennedy

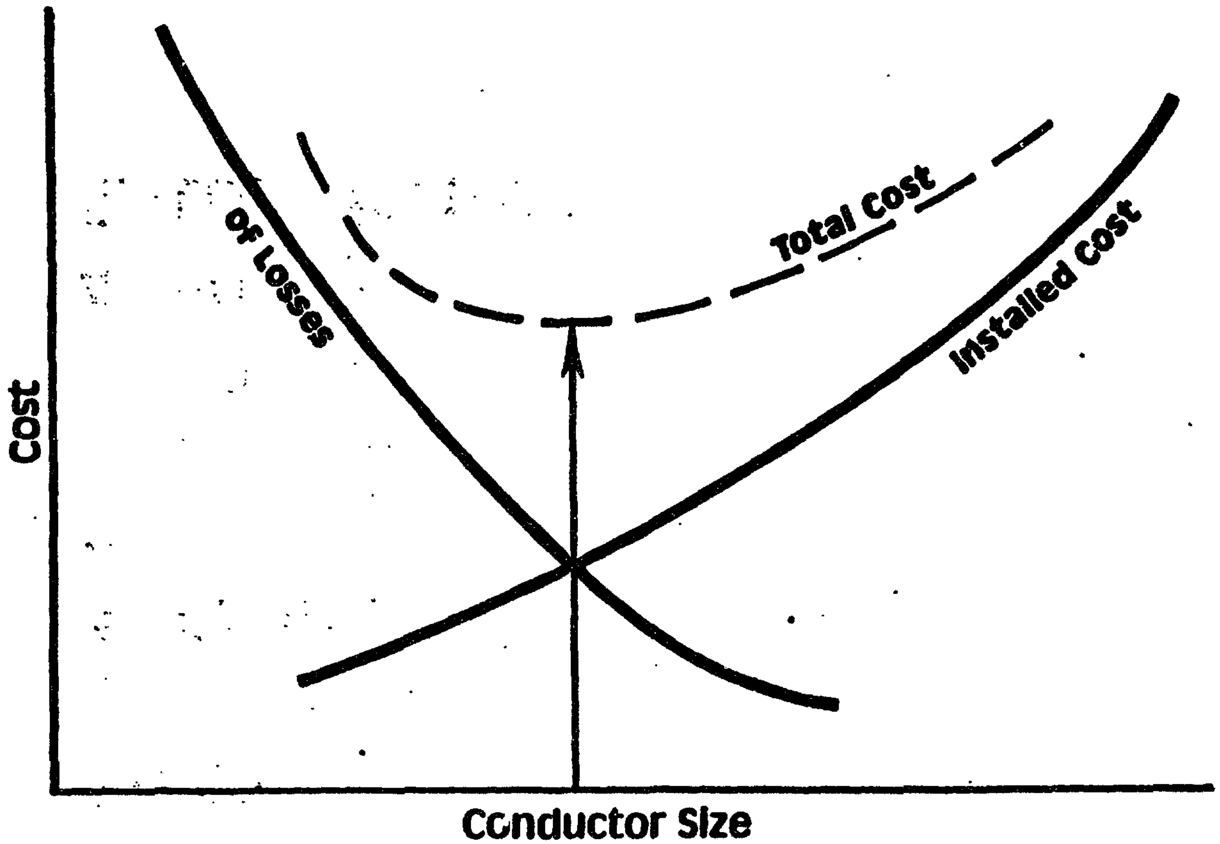


Figure 1

Page 7

To calculate the conductor losses:

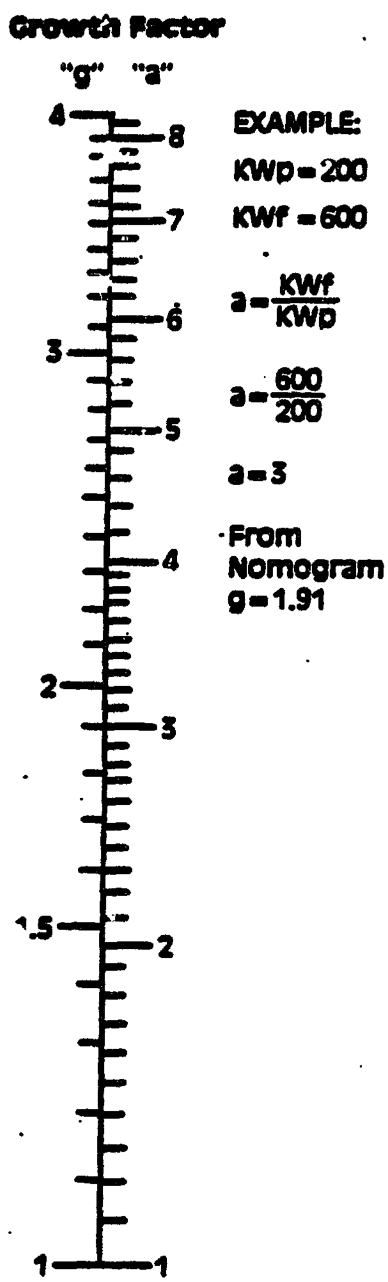
1. Conductor size and material
2. Peak load on the conductor in kilowatts (kW)
3. Power factor
4. Voltage
5. Load factor

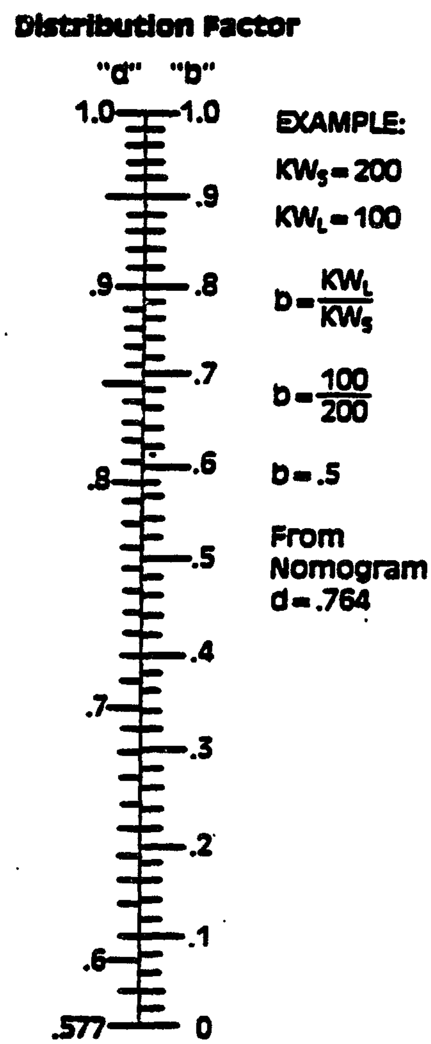
Figure 1

The peak load must be modified by two factors:

- Growth Factor
- Distribution Factor

Figure 2
Growth Factor and Distribution Factor



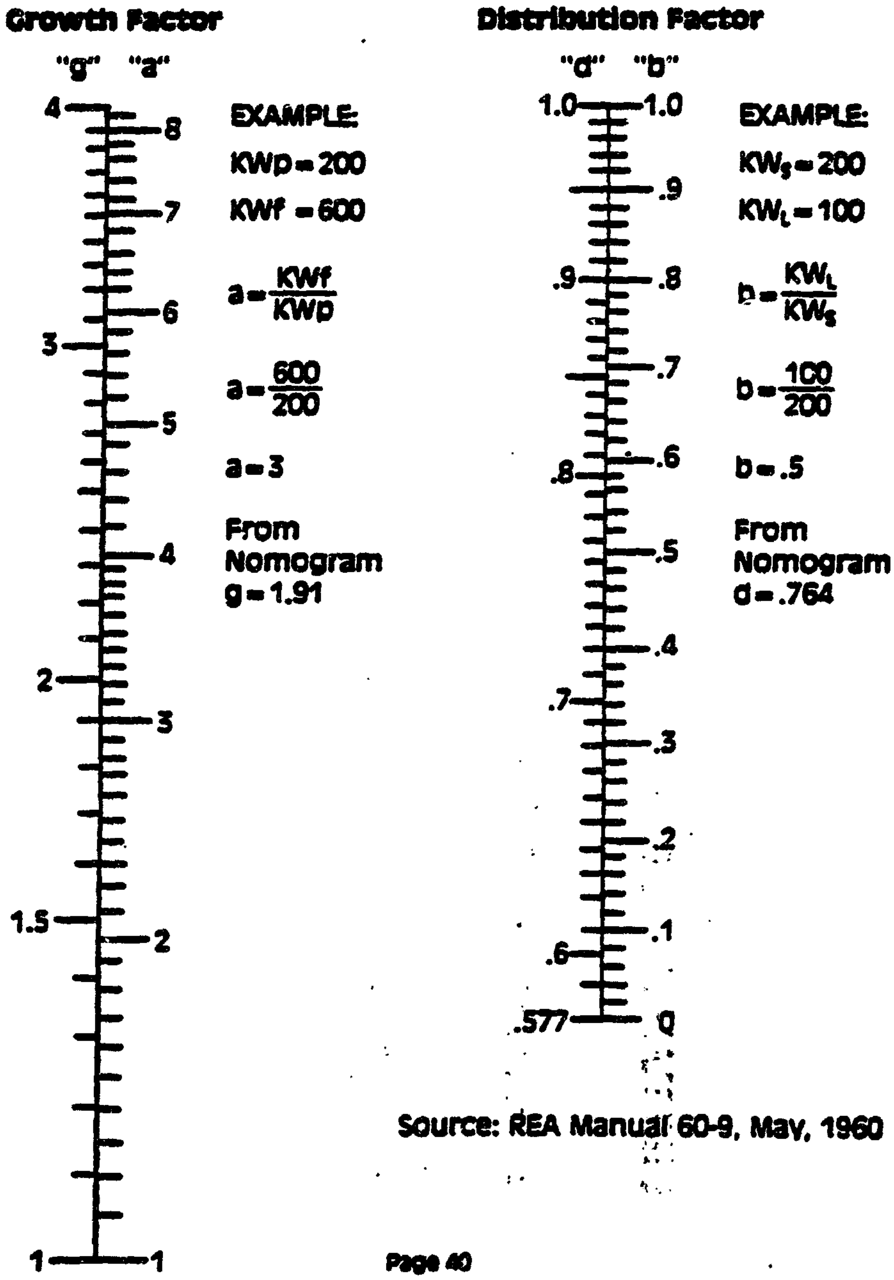


Source: REA Manual 60-9, May, 1960

Growth Factor:

- Ratio future load to present load
- Enter the nomograph of Figure 2

Figure 2
Growth Factor and Distribution Factor



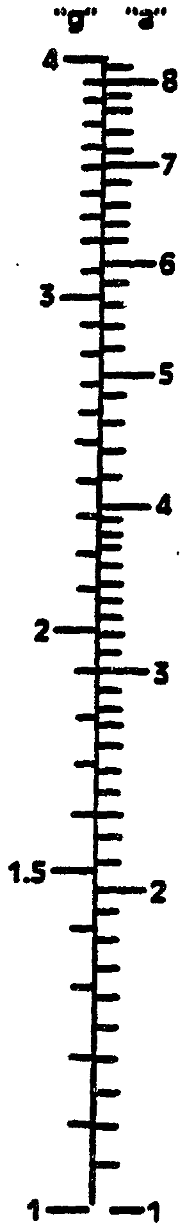
Source: REA Manual 60-9, May, 1960

Distribution Factor:

- Ratio load at the end to load at source
- Enter the nomograph of Figure 2

Figure 2
Growth Factor and Distribution Factor

Growth Factor



EXAMPLE:

KWp = 200

KWf = 600

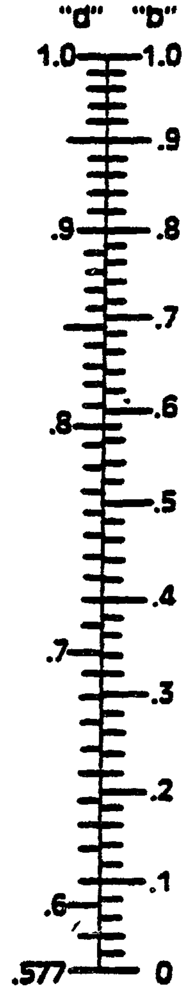
$a = \frac{KWf}{KWp}$

$a = \frac{600}{200}$

a = 3

From Nomogram
g = 1.91

Distribution Factor



EXAMPLE:

$KW_S = 200$

$KW_L = 100$

$b = \frac{KW_L}{KW_S}$

$b = \frac{100}{200}$

b = .5

From Nomogram
d = .764

Source: REA Manual 60-9, May, 1960

Load Factor Formula:

$$\frac{\text{total annual energy}}{\text{(peak month's demand) } 8760} = \text{load factor}$$

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Loss Factor Formula:

$$\text{loss factor} = .9(\text{load factor})^2 + .1(\text{load factor})$$

Loss Formula:

$$\text{kWh loss} = \frac{(\text{Peak kW})^2(\text{Resistance per phase per mile})(\text{Loss factor})(8760)}{(\text{kV})^2(\text{Power factor})^2(\text{Number of phases})(1000)}$$

Loss Formula Reduced:

kWh loss = (Peak kW)²(Conductor constant)

Table 1A
CONDUCTOR CONSTANTS—ACSR

SINGLE-PHASE LINES

System Load Factor	#4	#2	1/0	2/0	3/0	4/0	266.8 KCMIL	336.4 KCMIL	477 KCMIL	566.5 KCMIL
.30	.0519	.0327	.0206	.0163	.0129	.0103	.00810	.00644	.00454	.00390
.40	.0860	.0541	.0341	.0271	.0215	.0171	.0134	.0107	.00752	.00645
.50	.1285	.0809	.0509	.0405	.0321	.0255	.0201	.0159	.0112	.00964
.60	.1794	.1130	.0711	.0565	.0449	.0356	.0280	.0223	.0157	.0135
.70	.2388	.1503	.0947	.0753	.0597	.0474	.0373	.0296	.0209	.0179
.80	.3065	.1930	.1215	.0966	.0766	.0609	.0479	.0380	.0268	.0230
.90	.3827	.2409	.1517	.1206	.0957	.0760	.0598	.0475	.0335	.0287
1.00	.4673	.2942	.1852	.1473	.1168	.0928	.0730	.0580	.0409	.0350

V-PHASE LINES

System Load Factor	#4	#2	1/0	2/0	3/0	4/0	266.8 KCMIL	336.4 KCMIL	477 KCMIL	566.5 KCMIL
.30	.0259	.0163	.0103	.00817	.00648	.00515	.00405	.00322	.00227	.00194
.40	.0430	.0271	.0170	.0135	.0107	.00854	.00672	.00533	.00376	.00322
.50	.0642	.0404	.0255	.0202	.0161	.0128	.0100	.00797	.00562	.00482
.60	.0897	.0565	.0356	.0283	.0224	.0178	.0140	.0111	.00785	.00673
.70	.1194	.0752	.0473	.0376	.0298	.0237	.0187	.0148	.0104	.00895
.80	.1533	.0965	.0608	.0483	.0383	.0305	.0239	.0190	.0134	.0115
.90	.1914	.1204	.0759	.0603	.0478	.0380	.0299	.0237	.0167	.0143
1.00	.2336	.1471	.0926	.0736	.0584	.0464	.0365	.0290	.0204	.0175

3-PHASE LINES

System Load Factor	#4	#2	1/0	2/0	3/0	4/0	266.8 KCMIL	336.4 KCMIL	477 KCMIL	566.5 KCMIL
.30	.0173	.0109	.00685	.00545	.00432	.00343	.00270	.00215	.00151	.00130
.40	.0286	.0180	.0114	.00903	.00717	.00569	.00448	.00356	.00251	.00215
.50	.0428	.0270	.0170	.0135	.0107	.00851	.00669	.00532	.00375	.00321
.60	.0598	.0377	.0237	.0189	.0150	.0119	.00934	.00742	.00523	.00449
.70	.0796	.0501	.0315	.0251	.0199	.0158	.0124	.00988	.00696	.00597
.80	.1022	.0643	.0405	.0322	.0255	.0203	.0160	.0127	.00894	.0766
.90	.1276	.0803	.0506	.0402	.0319	.0253	.0199	.0158	.0116	.00956
1.00	.1558	.0980	.0618	.0491	.0389	.0309	.0243	.0193	.0136	.0117

Application:

a. Description of the line section
b. Wire size
c. Length of the section
d. System load factor
e. Annual peak power (kW) (effective)
f. Voltage
g. Power factor

Assume:

- 7.2/12.5 kV system
- 90 percent power factor.

Power Factor Multiplier:

$$\frac{(.90)^2}{(PF)^2}$$

Voltage Multiplying Factor:

$$\frac{(7.2\ \text{kV})^2}{(\text{actual voltage})^2}$$

Method:

1. Transformer nameplate rating, i.e., 10 kVA, 25 kVA, etc.

2. Number of customers served by the transformer

Determine if customers high-use or low-use:

- Low-use customers load of approximately 1,500 kWh
- High-use customers approxmiately 3,000 kWh.

Table 2
TRANSFORMER LOADING AS A PERCENT OF RATING AND LOSS FACTOR

LOW-USE CUSTOMERS

Number of Customers	Nameplate Rating—KVA 10	15	25	50	100	Loss Factor
1	120	80	48	24	12	.026
2	—	144	87	43	22	.030
3	—	197	119	59	30	.035
4	—	—	148	74	37	.039
5	—	—	169	85	42	.045
6	—	—	190	95	48	.051

HIGH-USE CUSTOMERS

Number of Customers	10	15	25	50	100	Loss Factor
1	—	149	89	45	22	.029
2	—	—	162	81	40	.034
3	—	—	—	110	55	.039
4	—	—	—	135	68	.044
5	—	—	—	157	79	.051
6	—	—	—	177	89	.056

Note: Dashes indicate transformers loaded above 200% of rating. This is not recommended.

Figure 3a
Transformer Losses
Standard Transformers
(97.8% Efficiency)

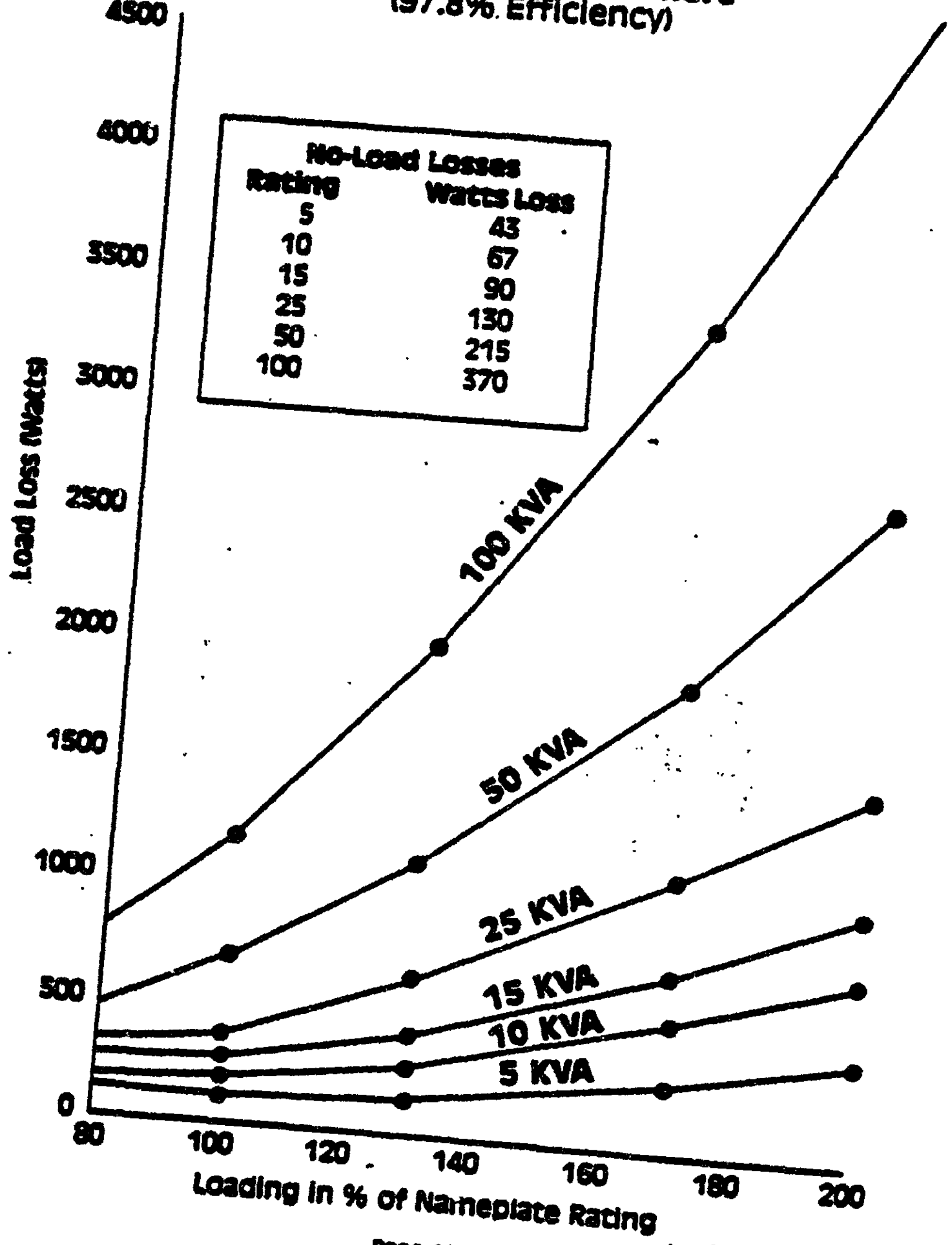


Figure 3b
Transformer Losses
High-Efficiency Transformers
(98.4% Efficiency)

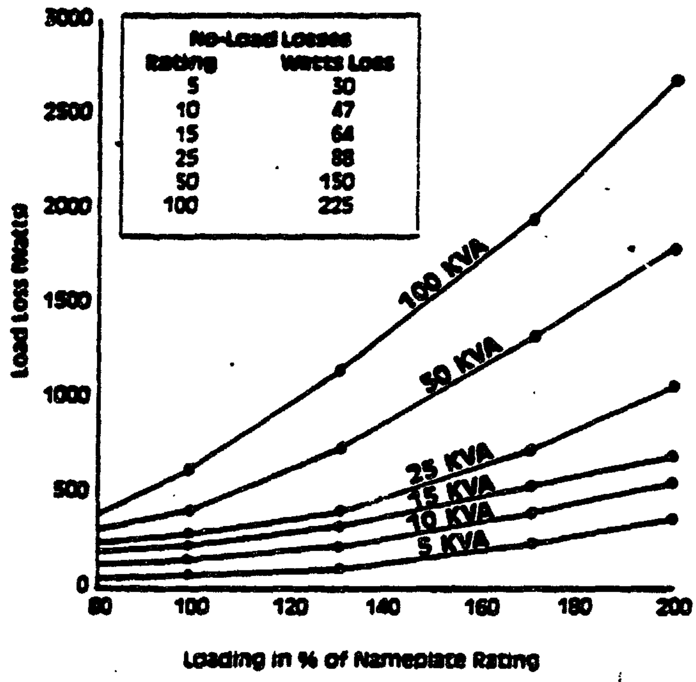
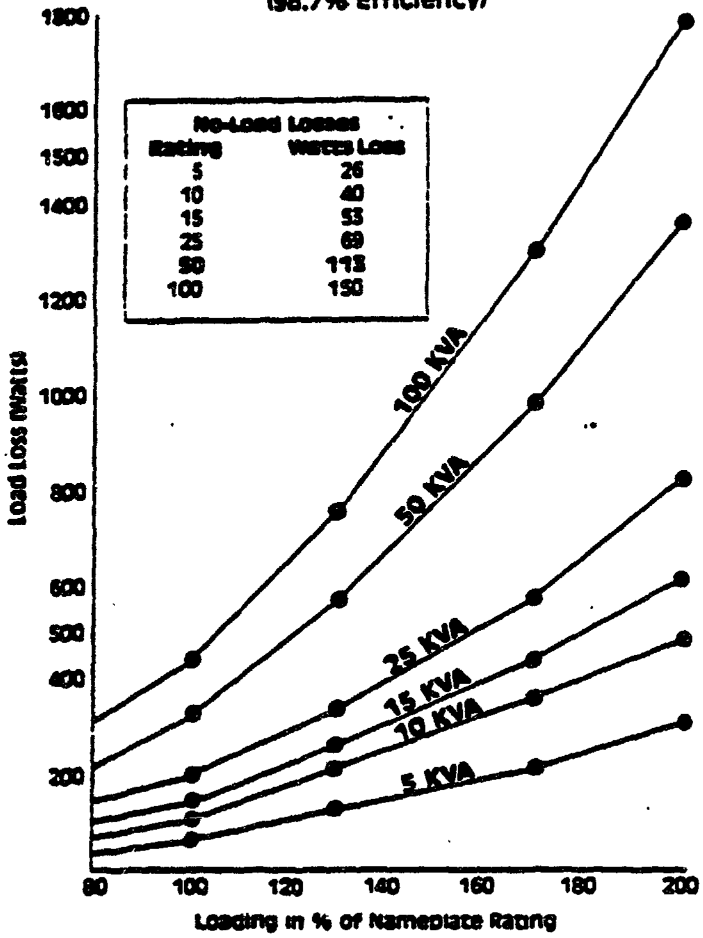


Figure 3c
Transformer Losses
Very High-Efficiency Transformers
(98.7% Efficiency)



Economics of Loss Reduction Method:

1. Calculation of kWh savings
2. Calculation of annual benefits
3. Calculation of annual costs

The time period:

- The useful life remaining in existing equipment, which will be replaced before it is necessary to do so by higher efficiency equipment.

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Table 3c
COST PER ADDITIONAL DOLLAR OF INVESTMENT

FACTORS FOR DETERMINING AVERAGE INVESTMENT COST

Study Period (Years)	Cost of Capital					
	5%		10%		15%	
	New	Old	New	Old	New	Old
5	0.0651	0.2310	0.1061	0.2638	0.1523	0.2983
10	0.0651	0.1295	0.1061	0.1627	0.1523	0.1993
20	0.0651	0.0802	0.1061	0.1175	0.1523	0.1598

Table 3c
COST PER ADDITIONAL DOLLAR OF INVESTMENT

FACTORS FOR DETERMINING AVERAGE INVESTMENT COST

Study Period (Years)	Cost of Capital: 5% New	5% Old	10% New	10% Old	15% New	15% Old
5	0.0651	0.2310	0.1061	0.2638	0.1523	0.2983
10	0.0651	0.1295	0.1061	0.1627	0.1523	0.1993
20	0.0651	0.0802	0.1061	0.1175	0.1523	0.1598

Typical Costs

- **Reconductor**
  $35,000 to $45,000 per mile.
- **Convert Single-Phase to Three-Phase (Add Two Phases)**
  $30,000 to $35,000 per mile.
- **Convert V Phase Line to Three-Phase Line (Add One Phase)**
  $25,000 to $30,000 per mile:
- **Reinsulate 1 ϕ 7.2/12.5 kV Line to 1 ϕ 14.4/24.9 kV**
  $5,000 per mile.
- **Reinsulate 3 ϕ 7.2/12.5 kV Line to 3 ϕ 14.4/24.9 kV**
  $15,000 per mile.
- **Change Out Transformers**

10 KVA	$550 each
15 KVA	585 each
25 KVA	680 each
50 KVA	975 each

- **Add Capacitors**
  $3.50 to $7.50 per KVAR.

Table 3c
COST PER ADDITIONAL DOLLAR OF INVESTMENT

FACTORS FOR DETERMINING AVERAGE INVESTMENT COST

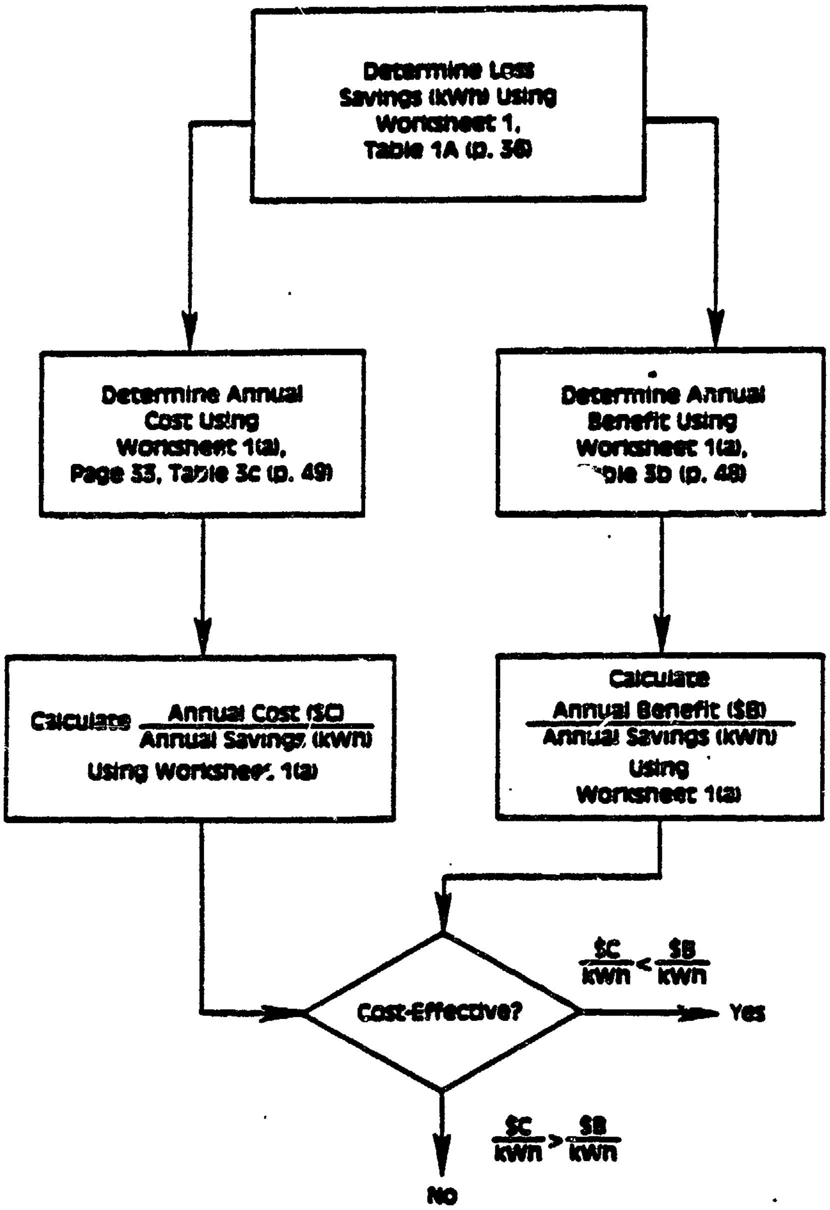
Study Period (Years)	Cost of Capital					
	5%		10%		15%	
	New	Old	New	Old	New	Old
5	0.0651	0.2310	0.1061	0.2638	0.1523	0.2983
10	0.0651	0.1295	0.1061	0.1627	0.1523	0.1993
20	0.0651	0.0802	0.1061	0.1175	0.1523	0.1598

Table 3b
SAVINGS FROM LOSS REDUCTIONS ON CONDUCTORS AND LOAD-LOSS REDUCTIONS ON TRANSFORMERS

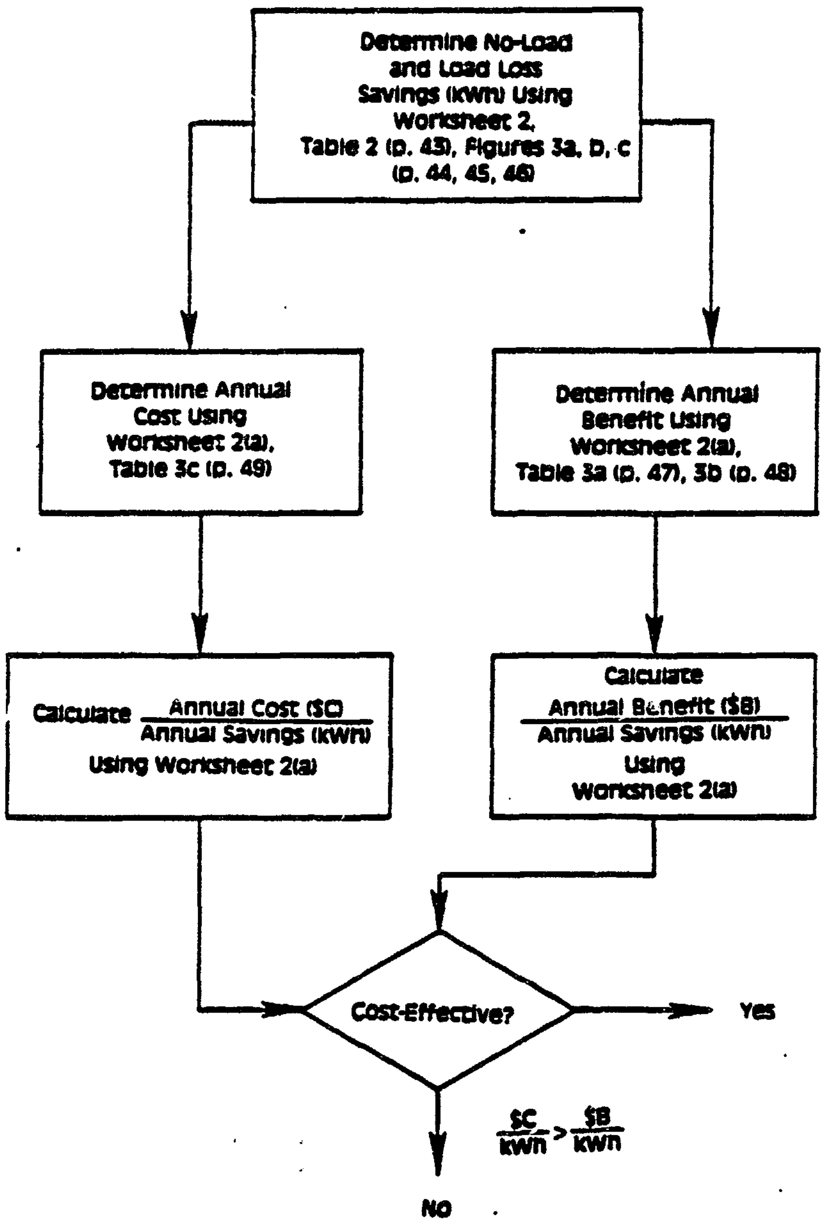
FACTORS FOR DETERMINING AVERAGE VALUE PER kWh BASED ON BPA'S PF-1 RATE

System Load Factor/ Study Period (Years)	Dollars per kWh At Given Cost of Capital 5%	10%	15%
40% System Load Factor			
5	$0.0353	$0.0346	$0.0340
10	0.0429	0.0413	0.0400
20	0.0551	0.0504	0.0465
50% System Load Factor			
5	$0.0277	$0.0272	$0.0266
10	0.0335	0.0324	0.0313
20	0.0432	0.0395	0.0364
60% System Load Factor			
5	$0.0231	$0.0230	$0.0224
10	0.0281	0.0273	0.0263
20	0.0363	0.0332	0.0307

RECONDUCTOR COST-EFFECTIVENESS CALCULATIONS



TRANSFORMER REPLACEMENT COST-EFFECTIVENESS CALCULATIONS



Economic Evaluation Procedure:

- Compare annual costs to annual savings.
- If the savings exceed costs proposal is feasible.

WORKSHEETS

REGIONAL SEMINAR ON ELECTRIC POWER LOSS REDUCTION IN THE CARIBBEAN

KINGSTON, JAMAICA

JULY 2-7, 1989

BARRY KENNEDY

Example 1—

Reconductor the feeder section with either 477 or 556.5 kcmil conductor.

Examples characteristics:

- Voltage: 7.2/12.5 kV
- Conductor: 336.4 kcmil ACSR, three-phase
- Load factor: 40 percent
- Power factor: 90 percent
- Present source-end load: 6,000 kW
- Present load-end load: 5,000 kW
- Study period: 5 years
- Future load (in 5 years): 9,000 kW

Worksheet 1(a)
ECONOMIC ANALYSIS - CONDUCTOR LOSSES

Items	Existing	Trial 1	Trial 2	
A. kWh Loss Savings				
Conductor size	______ kcmil	______ kcmil	______ kcmil	(1)
Study period	______ years	______ years	______ years	(2)
Load factor	______ %	______ %	______ %	(3)
Power factor	______ %	______ %	______ %	(4)
Voltage	______ kV	______ kV	______ kV	(5)
Losses	______ kWh	______ kWh	______ kWh	(6)
Loss savings (existing minus Trial 1)		______ kWh		(7)
Loss savings (existing minus Trial 2)			______ kWh	(7)
B. Annual Benefit from System Modification				
Loss savings (Item 7)		______ kWh	______ kWh	(8)
Factor from Table 3b		$______ /kWh	$______ /kWh	(9)
Average annual savings from loss reduction (Item 8 times Item 9)		$______	$______	(10)
C. Annual Cost of Making Loss Savings Investment				
Value of existing equipment to be retired:				
Salvage value		$______	$______	(11)
Factor from Table 3c for ___ years		______	______	(12)
Annualized credit for salvage (Item 11 times Item 12)		$______	$______	(13)
Value of new equipment to be installed:				
Installed cost		$______	$______	(14)
Factor from Table 3c		______	______	(15)
Annualized cost (Item 14 times Item 15)		$______	$______	(16)
Net annualized cost (Item 16 minus Item 13)		$______	$______	(17)
Item 17 divided by Item 7		$______ /kWh	$______ /kWh	(18)
Item 18 times 1,000		______ mills/kWh	______ mills/kWh	(19)

EXAMPLE 6—Replacement of Transformers Assumption:

For this example, a 50 kVa standard efficiency transformer serving six high-use customers will be considered.

WORKSHEET 1

	EXISTING	TRIAL 1	TRIAL 2
LINE SECTION: ______			
CONDUCTOR SIZE:	______	______	______
NUMBER OF PHASES:	______	______	______
LOAD FACTOR:	______	______	______
ENTER CONSTANT FROM TABLE I	______	______	______

VOLTAGE MULTIPLIER

VOLTAGE	MULTIPLIER
4.16/7.2 KV	3.0
6.9/8.0 KV	2.44
7.2/12.5 KV	1.00
7.6/13.2 KV	.893
14.4/24.9 KV	.25
19.9/34.5 KV	.13
69 KV	.0328
115 KV	.0118

	EXISTING	TRIAL 1	TRIAL 2
ENTER MULTIPLIER FOR VOLTAGE OF ______ KV	______	______	______

POWER FACTOR MULTIPLIER

POWER FACTOR	MULTIPLIER
80%	1.27
85%	1.12
90%	1.00
95%	.90
100%	.81

	EXISTING	TRIAL 1	TRIAL 2
ENTER MULTIPLIER FOR POWER FACTOR OF ______ %	______	______	______

	CONSTANT	X	VOLTAGE MULTIPLIER	X	POWER FACTOR MULTIPLIER	X	KW ^{2}	= KWH LOSSES
EXISTING CONDUCTOR	______	X	______	X	______	X	(______) ^{2}	______ KWH/MI
TRIAL 1	______	X	______	X	______	X	(______) ^{2}	______ KWH/MI
TRIAL 2	______	X	______	X	______	X	(______) ^{2}	______ KWH/MI

EXAMPLE 6—Replacement of Transformers

Example 6 demonstrates the procedure to be followed to evaluate the economic feasibility of replacing an existing transformer with a higher efficiency transformer or a transformer with a higher nameplate rating.

Worksheet 2(a)
ECONOMIC ANALYSIS - DISTRIBUTION TRANSFORMERS

Items	Existing	Trial 1	Trial 2	
A. kWh Loss Savings				
No-load losses	______ kWh	______ kWh	______ kWh	(1)
No-load loss savings (existing minus trial)		______ kWh	______ kWh	(2)
Load losses	______ kWh	______ kWh	______ kWh	(3)
Load loss savings (existing minus trial)		______ kWh	______ kWh	(4)
Total savings (Item 2 plus Item 4)		______ kWh	______ kWh	(5)
B. Annual Benefit of Early Installation of New Equipment				
Benefits from reduced no-load losses:				
NNL savings (Item 2)		______ kWh	______ kWh	(6)
Factor from Table 3a		$______ /kWh	$______ /kWh	(7)
Average annual savings from NNL reduction (Item 6 times Item 7)		$______	$______	(8)
Benefits from reduced load losses:				
LL savings (Item 4)		______ kWh	______ kWh	(9)
Factor from Table 3b		$______ /kWh	$______ /kWh	(10)
Average annual savings from LL reduction (Item 9 times Item 10)		$______	$______	(11)
Total average annual benefits (Item 8 plus Item 11)		$______	$______	(12)
Total annual kWh saved (Item 5)		______ kWh	______ kWh	(13)
Average benefit per kWh saved (Item 12 divided by Item 13 times 1,000)		______ mills/kWh	______ mills/kWh	(14)
C. Annual Cost of Early Installation of New Equipment				
Existing equipment value:				
Salvage value of existing equipment		$______	$______	(15)
Factor from Table 3c (for ___ years)		______	______	(16)
Annualized value of salvage credit (Item 15 times Item 16)		$______	$______	(17)
New Equipment Cost:				
Installed cost of new equipment		$______	$______	(18)
Factor from Table 3c (for ___ years)		______	______	(19)
Annualized cost of new equipment (Item 18 times Item 19)		$______	$______	(20)
Net annualized cost (Item 20 minus Item 17)		$______	$______	(21)
Total annual kWh saved (Item 5)		______ kWh	______ kWh	(22)
Average cost per kWh saved (Item 21 divided by Item 22 times 1,000)		______ mills/kWh	______ mills/kWh	(23)

ECONOMIC ANALYSIS OF POWER LOSS REDUCTION PROJECTS1/

By

Mr. Luis E. Gutiérrez-Santos

I. INTRODUCTION

The purpose of the paper is to present a methodological framework for the economic analysis of "power loss reduction projects" (PLRP). This paper is necessary because, even though technical staff are aware of the problem of power losses and of the technical solutions, the means to realize the benefits are less evident, and the specialized literature lacks a comprehensive treatment for analyzing and justifying PLRP in an economic context2/. Thus, the emphasis of this paper is on the rational for benefit estimation. The adequate measure of economic costs and benefits of PLRP would help to assess better their importance within the limited investment budgets of the electricity supply industries of less developed countries. There are two types of power losses: physical or technical, and non-technical losses (also known as unpaid, irregular or non-registered consumption, power theft, etc.). The projects to reduce technical losses (TL) are also known as network rehabilitation investments. The projects to reduce non-technical losses (NTL) are also called revenue recovery (or revenue enhancement) projects.

A certain level of power losses is unavoidable on physical and economic grounds. However, losses above 12 to 15% of the energy requirements (net generation plus purchases) are unacceptably high. PLRP would not be needed if proper planning had been the case and financial resources had been available in the past. Such projects are a consequence of past policy mistakes, which led to the deferment of necessary expenditures for asset maintenance and replacement. In spite of the fact that generally the largest concentration of the industry's capital is in distribution, it is where financial shortages were first felt, not necessarily in terms of a decline in the rate of connections but as regards asset maintenance and replacement. System weaknesses manifest themselves less spectacularly (high losses, low voltages, etc.), than generation shortages and a slow down in the rate of connections. Dwindling resources were concentrated in expanding generating capacity and for electrification programs, as visible signs of progress. This explains why losses reached extremely high

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1/ This paper is the author's exclusive responsibility and does not necessarily represent the points of view of OLADE and/or the World Bank.

2/ Munasinghe and Scott (36) are the first who studied the literature on these projects in order to examine different methods for reducing losses and incorporating the results of the economic analysis into the criteria for the design and operation of distribution circuits.

levels in countries with financial difficulties, specially during the debt crisis. Indeed, while levels of TL under 10% are technically feasible, in various LDCs this figure exceeds 20%, of which the greatest share represent distribution losses. Furthermore, when the service is of very poor quality, theft has greater social acceptance compounding the dimensions of the problem.

The poor condition of distribution networks, the resulting degradation of service rendered, and the deteriorated image of the utilities in most LDCs are largely due to the tariff distortion that has prevailed since the 1970s. This situation has a number of causes, but probably the most important had to do with the oil crisis in 1973 when the price of oil quadrupled, resulting in large increases in costs for utilities with thermal generation. The utilities were prevented, due to policy considerations, from transferring these cost increases to the users. If the utilities had been allowed to do so, probably supply conditions, service quality and reliability would be better and PLRP would not be needed. A good investment policy is merely the other side of a good pricing policy. The public service feature of electricity supply has meant in a large number of cases that governments have prevented utilities from charging the full cost of supply, especially in inflationary contexts. Public enterprises have been used as another policy instrument for fighting inflation, giving rise to a sequence of problems:

1. low relative tariffs stimulate consumption even further;
2. the utility reduces wages and salaries adjustments and postpones necessary expenditures and investment; and
3. supply efficiency and quality of the service decline, increasing operating expenses and costs to users of blackouts and brownouts.

Continuation of this financial, operative and planning degradation, reaches a point in which the required tariff increases to overcome the financial shortages, are so steep that the political costs are deemed unacceptable, not only because of the magnitude of the increases, but because the quality of the service is so poor. Thus, where this situation has prevailed for a considerable time, not only power utilities have lost key technical personnel and neglected asset maintenance and replacement, but as time goes on it becomes increasingly difficult to correct the situation. As a result, after several years of financial and operational neglect the losses and outages in the primary and secondary distribution networks of many LDCs have reached levels high enough to justify the design of specific projects to reduce them.

The interest today for PLRP has to do with the foreign exchange shortages posed by the foreign debt problem and the high international cost of energy. PLRP are an important form of energy conservation, in that they reduce waste in transportation and distribution of electric power. The level of losses is excessive when it is cheaper to reduce them than to increase supply capacity. At the margin, the value to the country of each kWh lost is the long term marginal cost; therefore it is worth investing to reduce such losses whenever the cost of doing so is lower than this marginal cost.

The purpose of the economic analysis is to show that the benefits of power loss reduction are greater than, or at least equal to, the benefits foregone elsewhere in the economy when the funds are committed to the project. Cost benefit analysis (CBA) is a more efficient way of allocating resources than the traditional methodology of cost minimization, since it enables the ranking of power supply projects and the comparison with other projects in the energy sector and elsewhere in the economy. CBA allows for a better use of the limited investment funds of the public sector budget.

The following sections sets out the rationale for the economic analysis of PLRP, distinguishing between TL and NTL. Section II deals with the information needed for the economic analysis of PLRP. Section III examines projects to reduce TL, while section IV deals with NTL.

II. POWER LOSS REDUCTION PROJECTS

Technical losses consist of the energy produced and lost through transmission, transformation and distribution. TL arise from the resistance of conductors and equipment to electrical current. TL represent added production costs to the utility. On the other hand, non-technical losses (NTL) consist of that energy consumed but not paid for. NTL arise mainly from theft and fraud, and to a lesser extent, due to uncalibrated and broken meters, errors and problems with meter reading, invoicing and collection, etc. NTL translate into less sales revenue to the utility.

Each type of power losses gives rise to two different sorts of projects. TL can be reduced, among other ways, through better design, selection and location of substations, capacitor banks, voltages and primary circuits, and a better combination of transformers, secondary circuit conductors and connections. NTL can be reduced by controlling theft and fraud, and solving the problems in meter reading, billing and collection.

When both losses are present in a given distribution network, projects for the reduction of NTL are appraised first. This is necessary in order to prevent overestimation of benefits, since if unpaid consumption is reduced so will part of the load, and hence the associated levels of technical losses.3/

CBA is applied to projects, not programs. The analysis is done for each group of interdependent works that fulfill the same objective. This means, for PLRP, examining each independent circuit separately. When the rehabilitation of a number of secondary circuits depend on the renovation of a primary circuit, the project encompasses all of them. Although substations are typically built to increase the supply capacity, their redesign and relocation can also help reduce losses. Increasing the capacity of a substation, or installing a new one, changes the load distribution and results in lower losses. In a number of projects it is necessary to increase the capacity, since rehabilitation can increase the load. In this case the substation forms part of the project. When the substation cannot operate without a new subtransmission line, the substation and the line are examined as part of the PLRP. The economic criterion for deciding whether a specific component should be part of the project is: if it

3/ Even though this will be developed further on, it is convenient to note here that in some cases the reduction of NTL might lead to an increase in the load.

does not increase the net present value (NPV) of the project, then it should not be part of the project.

The appraisal of PLRP proceeds in stages. In the first stage, the program stage, a global analysis is carried out to appraise the dimensions of the problem and the convenience of the program. This global ex-ante appraisal is done for typical projects based on representative samples. Execution of the second stage depends whether the results of the first stage were positive. On the second stage, what can be called the executive project, or design stage, each project is examined in greater detail. The type and quality of the information required for examining the program and the project are different. In the program stage, the nature of the data requirements are for planning purposes, while in the project stage more detailed estimates of costs and benefits are needed. An approach for gathering the necessary information for the appraisal of typical projects within a power loss reduction program is described in what follows.

The gathering of data proceeds from the general to the specific. The easiest information is obtained first. The starting point is the energy balance of the system:

GENR = TOTL + ES

where

GENR = generation requirements,
TOTL = total system losses, and
ES = total energy sales.

Second, TOTL are differentiated by tension levels, to separate those relating to transmission (TRNL) from the remainder (OTHL).

OTHL = TOTL - TRNL

TRNL can be estimated as the difference between the energy supplied to the output busbars at the generating plants and that received at the substations. However, in practice these measurements are not consistent in interconnected systems, requiring an indirect estimation. Power losses are estimated with simulation models for maximum load flows. Average energy losses are then calculated using the loss factor, which states the relationship between average energy losses and power losses. It can be expressed as an empirical equation reflecting system characteristics and conditions4/.

Third, losses in primary circuits are in turn estimated by measuring the load flows leaving the substations and received at the distribution transformers. As in the previous step, it is difficult, and in this case expensive, to do this, requiring an indirect estimation. A load flow simulation model is used to determine primary distribution losses (PDL).

4/ The loss factor (lf) is expressed as lf = ([EL(kWh)/t]/PL(kW)) where EL(kWh) represents energy losses during period t (generally a year, making t = 8,760 hours), and PL(kW) power losses during the same period. An expression commonly used in Brazil in planning studies is as follows: lf = .2(df) + .8(df)^2, where df is the load factor of the line. In the Dominican Republic this expression is different, viz.: lf = .5(df) + .4(df)^2.

$SDL = OTHL - PDL$

Fourth, a survey is carried out in a representative sample of secondary circuits, metering the energy from the transformer, counting the number of meters and link-ups (legal or clandestine) in each circuit, and recording the user's consumption at the beginning and end of the survey. It is important to note at this stage, that the information comes from a sample of circuits, and that the selection of the sample is very important and should be as representative as possible. A first selection criterion could be by main consumption type (industrial, residential, commercial, etc.). A second criterion could be by consumption levels (for instance for residential circuits, by type of neighborhood: high, medium and low income). Once the representative samples are selected, measurements are undertaken for brief periods. (Visbal [49] proposes a methodology for this purpose.)

Once the results of the survey are known, they are subsequently expanded to the system level and for the year with adequate parameters, such as average number of transformers by circuit, average consumption level by user, average number of users, seasonal correction factors, etc. With these system estimates, the secondary technical and non-technical losses can be computed. This can be expressed for a circuit i as follows:

$SDL_i = QS_i - \Sigma_u c_{ui}$, and
$SDL_i = TL_i + NTL_i$

where

QS_i = energy from the transformers;
c_{ui} = consumption of user u in circuit i, for $_u = 1, n$; and
n = number of users in the circuit.

The first equation states that the difference between the energy delivered to the secondary circuit, QS_i, and the consumption, $\Sigma_u c_{ui}$, corresponds to the total distribution losses in the circuit i, SDL_i. The second equation states that these losses are technical and non-technical in nature.

Technical losses can be estimated using simulation models of load flows for the typical distribution circuit identified. NTL can then be estimated by subtraction.

$NTL_i = SDL_i - TL_i$

The non-technical losses can be further studied in order to determine their origin: theft, fraud, unadjusted meters, inadequate meters, consumption in excess of the contracted amounts for fixed tariff users, or other reasons. The differentiation of NTL by source is necessary to design an adequate program of loss reduction.

III. PROJECTS TO REDUCE TECHNICAL LOSSES

Technical losses occur when a current of electrons encounters the natural resistance inherent in the medium, somewhat analogous to losses caused by friction. These losses occur at all stages, from the generation plants to the users' equipment, transformation, transmission, subtransmission and distribution. Technical losses also occur at the consumer level.

The relation between losses (L), the current (I) and the resistance (R) is expressed as follows:

$$L = I^2R$$

where demand (the load) is analogous to the current I, and the capacity of supply to R, the resistance of the medium (e.g., diameter of line, conductivity of the material, distance between supply and load, ambient temperature, etc.). Each system component (line, substation, conductor, etc.) has a resistance associated with its physical and technical characteristics. The equation shows that losses increase geometrically as demand rises and that they are directly proportional to the resistance of the medium through which the current is flowing.

Losses can thus be reduced by either decreasing demand or increasing capacity (reducing the resistance). Aside from load management measures, like tariff restructuring and conservation, load reduction is achieved on the supply side by dividing the load among various components, either by building parallel works or by expanding existing capacity. However, reducing the load or increasing capacity costs money. The economic problem is to find the optimum point at which the benefit of reducing losses is equivalent to the cost.

The economic benefits of PLRP for technical losses are, first, a reduction in generation requirements, leading to lower operating and expansion costs. Second, PLRP improve and expand available capacity, which in turn improves reliability of supply for existing users. Third, the reduction of power losses releases capacity for new users who previously could not be connected with a given standard of reliability. Fourth, rehabilitation may reduce expenditures on maintenance and emergency repairs, especially in old and deteriorated systems. Finally, reduced unit costs reflect (viz a viz the without project situation) greater investment resources and/or lower tariffs, resulting in an increase in supply and/or demand. It should be pointed out that a number of the above-mentioned effects have significant financial benefits for the power company, either in the form of lower costs and/or increased receipts5/.

In brief, a project to reduce technical losses may prevent during part (not necessarily all) of its existence some of the following effects: (a) higher technical losses; (b) a deterioration of service reliability; (c) supply shortages; (d) higher operating costs, and (e) unnecessarily high tariffs. In

5/ In an optimum pricing environment, all of the above economic benefits improve the financial position of the utility. However, in an non-optimal situation, where tariffs are below marginal costs, an increase in supply leads to added financial losses to the utility.

other words, if the project is not implemented some, or all, of these effects can be expected.

A. Cost/Benefit Analysis

The objective function to be maximized is the net present value (NPV) of the benefits (B_t) less the discounted costs (C_t) during the economic life of the project (n); i.e.

$$NPV = \Sigma_t [(B_t - C_t) / (1+i)^t]$$

where

t = 1, n, and
i = the opportunity cost of capital.

For simplification sake, consider all the benefit and cost flows below as expressed in discounted terms.

Benefit estimation considers the entire supply system, starting with the optimal alternative to minimize technical losses. The operation of system is then simulated with and without the project for each year of the planning horizon. If the project is worthwhile, the present worth of the net system benefits (PW_w) will be greater than without it (PW_{wo}). The benefits and costs for the "without project situation" (B_{wo} and C_{wo}) are subtracted from the benefits and costs with the project (B_w and C_w), obtaining the NPV of the project:

$$NPV = PW_w - PW_{wo}, \text{ and}$$
$$NPV = [B_w - C_w] - [B_{wo} - C_{wo}] \quad (A.1)$$

The system's benefits are the users' willingness to pay for the energy (WTP): sales plus consumer surplus. The total costs are, on the demand side, the users' costs of unserved energy, or service interruptions (UEC), and on the supply side, the total cost of the energy supplied (TC). That is,

B = WTP
C = TC + UEC

and substituting

PW = WTP - TC - UEC.

The total system costs of the energy supplied (TC) are the costs of generation (GC), transmission (RC) and distribution (DC):

TC = GC + RC + DC.

At the margin, smc = mcg + mct + mcd (system marginal cost equals the marginal costs of generation, transmission and distribution), the first two terms express the marginal cost of increasing bulk supply of electricity (mcq). Since PLRP aim to optimize costs by minimizing distribution losses, this can be expressed as

$$smc = mcq + mcd$$

and substituting

$$TC = mcq\ Q + mcd\ D$$

where

smc = system marginal cost
mcq = marginal cost of increasing bulk electricity supply (i.e., consumption plus distribution losses).
mcd = marginal cost of distribution
Q = bulk electricity supply.
D = net increase in energy demanded.

All of the above costs are present in the with and without project situation. An additional cost with the project is the project investment (I_p). Thus, substituting in equation (A.1), we have:

$$\begin{aligned} NPV &= [B_v - B_{wo}] - [C_v - C_{wo}] \\ &= [WTP_v - WTP_{wo}] - [(UEC_v + mcqQ_v + mcd_vD_v + I_p) - (UEC_{wo} + mcqQ_{wo} + mcd_{wo}D_{wo})] \end{aligned} \quad (A.2)$$

As PLRP principal aim is to reduce losses, we can assume the same demand with and without the project ($D_v = D_{wo}$), assumption which can later be released. We therefore expect the following relations:

$$WTP_v \geq WTP_{wo}$$
$$UEC_v < UEC_{wo}$$
$$Q_v < Q_{wo}$$
$$mcd_v \leq mcd_{wo}$$

Given the nature of PLRP, the long run marginal cost of bulk electricity requirements should basically stay the same. Thus, if the willingness to pay does not change, the previous expression may be simplified to

$$NPV = mcq[Q_{wo} - Q_v] + [UEC_{wo} - UEC_v] + [mcd_{wo} - mcd_v]D - I_p.$$

and since Q corresponds to demand D plus distribution losses L, we have

$$NPV = mcq[L_{wo} - L_v] + [UEC_{wo} - UEC_v] + [mcd_{wo} - mcd_v]D - I_p \quad (A.3)$$

$$\begin{bmatrix}\text{Net}\\\text{present}\\\text{value}\end{bmatrix} = \begin{bmatrix}\text{Generation}\\\text{cost}\\\text{savings}\end{bmatrix} + \begin{bmatrix}\text{Added}\\\text{reliability}\\\text{benefit}\end{bmatrix} + \begin{bmatrix}\text{Op \& Man}\\\text{distrib.}\\\text{savings}\end{bmatrix} - \begin{bmatrix}\text{Project}\\\text{investment}\end{bmatrix}$$

The main benefit of a decline in power losses is the savings of scarce resources in generation. This benefit is estimated by comparing the level of losses with and without the proposed project. The reduction in kWh is then valued at the relevant long run marginal cost; that is, the marginal cost of generation plus transmission up to the tension previous to the project tension. The mcq includes transmission losses and the cost of future expansions in generation and transmission.

The accumulated marginal cost increases when power goes from one tension level to another. There is a cost associated with: a) transforming power, b) the lines and equipment at a given tension, and (c) the losses. Evidently, generation cost savings should not include the cost of the project itself. Therefore, the relevant mc value for valuing the reduction in losses from the remodeling of a 13.8 kV network is the marginal cost at 34.5 kV, that is, the marginal cost of delivering electricity to the 13.8 kV network.

Savings in operation, repair and maintenance costs of distribution networks are a function of age, wear and tear, and their previous neglect. Distribution networks in need of rehabilitation are generally old, designed according to non-economic criteria, using different standards and non-standardized specifications, and for smaller loads. In many systems, equipment is subject to greater loads than originally intended for, receiving little or no adequate maintenance and, thus, breaking down often. Frequently, transformer connections do not take the number of phases into account, overloading one part of the transformer while under utilizing the rest. Conductors are overloaded and therefore overheated, becoming brittle with time and shatter easily. Poles are neither uniform nor safe and very often consist of tall sticks, generally leaning and supported by cables. Many poles are located near public highways and frequently fall down or are knocked over by vehicles. Hence, a grid rehabilitation project may reduce operation and maintenance costs, where a large share is repair expenditures, since it improves the installations in almost all of the above-mentioned respects.

The assumption of equivalent demands for (with and without the project) was previously adopted to simplify the exposition. However, in most cases as the project increases capacity and improves reliability, in due course it stimulates consumption. For example, city centers are generally old neighborhoods, avoided by business, office and residential buildings because of electricity service constraints. Rehabilitation removes these restrictions, leading to a greater demand for new connections. Furthermore, when rehabilitation reduces voltage variations, previous users who did not acquire any new equipment and/or appliances because of the poor quality of the service, buy them increasing their consumption. In this case, the objective function corresponds to equation A.2.

B. Benefit of Greater Reliability

In addition to saving resources in generation and stimulating additional consumption, the rehabilitation project also improves quality of supply. Two of the most relevant components of the quality of supply are the interruptions in service (power cuts), and voltage variations. The improvement in service reliability is estimated from the cost to the economy of not implementing the project. The relevant question is: What are the direct and indirect economic losses experienced by industrial, commercial, residential and other users as a result of supply failures?

The quality of supply depends on the security and homogeneity of the kWh delivered. Reliability is high when the number of interruptions is low. Likewise, the fewer the variations in voltage, the greater the homogeneity of power supply. The unserved energy cost (UEC) is the cost to the economy of a reduction in the reliability of the supply. This cost has two components, a direct and an indirect component. The former is measured in terms of what users suffer as a result of the interruption in supply, and the second involves the effects on the economy at large consequent upon the damages to consumers. In practice, a supply breakdown affects not only users but other sectors of the economy through the multiplier affects of the reductions in incomes and outputs.

Naturally, UEC is not a constant figure. It varies according to the stage of supply involved (generation, transmission, or distribution), or the region (rural or urban area, etc.), the type of users (energy intensive industries, low-income households, etc.), the duration, the time, whether it is a sudden or expected failure, and whether it takes the form of a power cut or a voltage variation.

The duration of an outage is longer for a forced shutdown of a generating plant, relative to transmission or distribution equipment. The frequency of outages in distribution is higher than in transmission or generation. The depth (i.e., the number of consumers affected) of an outage in generation is higher than transmission and distribution. In general, the costs of supply interruptions to industrial users are generally higher than for residential users, and the UEC in high-income neighborhoods is higher than in low-income ones. An outage in the morning is less damaging than one in the afternoon, when more users are consuming power. A power cut lasting one minute may be insignificant, while an hour's interruption may be very costly. A power failure generally occurs suddenly when the maximum demand cannot be met because of lack of capacity, while an energy failure can be managed (low water levels in the reservoirs). When users are aware that an interruption is going to occur they make the necessary preparations and thereby minimize the impact. In other words, the cost to users of an unexpected interruption in supply is greater than an anticipated one. The cost of a service interruption is greater than that of a voltage reduction. In the first instance, no energy is delivered, while in the second some is, even if less than normal.

There are various methods for estimating the cost of unserved energy, such as:

1. the aggregate value per unit of energy supplied in the past (Mattson [29], Telson [46], Jaramillo and Skoknic [25];

2. the user's willingness to pay for future supplies of electricity (Brown and Johnson [5], and Crew and Kleindorfer [8];

3. the direct losses resulting from supply breakdowns (Munasinghe and Gellerson [34], Munasinghe [35] and Sanghvi [41]), and

4. the cost of emergency equipment (Sanghvi [42], Bental and Ravid [3]).

Possibly the oldest approach is the production function (QF) approach. It involves the relationship between production and electricity consumed, from which an initial value is obtained for UEC, the cost of unserved energy. Jaramillo and Skoknic [25] used this approach in Chile in 1973. Telson [46] concluded in 1975 that U.S. systems were over-reliable. Notwithstanding its simplicity, the QF approach suffers from a number of shortcomings. For one thing, it tends to underestimate the costs to industries in which the interruption not only prevents production throughout its duration, but also damages inputs and equipment. Furthermore, QF tends to overestimate UEC in industries which can recover part of their lost output through extra shifts and/or other compensatory procedures.

According to Munasinghe and Gellerson [34], the willingness to pay approach (WTP) only considers the direct impact on users, which may not include other activities affected by the supply shortage. This is the case with the damage to materials, and lost productivity during the restart period after power is restored. Munasinghe and Gellerson therefore consider that to calculate UEC from users WTP, underestimates its real cost. As Anderson and Taylor [1] indicate, in principle there should be no difference in the value, since the direct opportunity cost of the unserved energy ought to be equivalent to the user's willingness to pay to avoid it. The advantages of this method are its simplicity and the minimum requirements. The most serious flaw of the WTP approach is that it does not consider the indirect opportunity cost, namely the effects elsewhere in the economy of the decline in the users' level of economic activity. It therefore underestimates the true UEC.

Munasinghe and Gellerson [34] suggest that UEC should be determined through user surveys in order to appraise the direct consequences. The industrial UEC becomes under this approach the industry's productivity losses; i.e., what the company stands to loose from a shortage in supply. The residential UEC is related to the value of the activities affected, be recreational or household tasks; and so on for different users.

There are some limitations with the "direct losses" (DL) method. First, surveys are resource intensive (time, money and information). Second, DL suffers from the limitation common to all hypothetical situations. If the interviewed have not suffered these costs (residential consumers), or if they have experienced them but have no way of estimating them (industrial users), they will tend to bias the results in their favor by exaggerating the harm done. Third, users may deliberately answer inaccurately because of fear of higher rates. Fourth, users may not reply, or may make mistakes, because lack of knowledge or have not thought about the issues entailed by the questions in the survey. Finally, it is not only the user's activities that suffer with the shortage in energy supply but also the rest of the economy, through the multiplier effects of the reduction in users' incomes.

Bental and Ravid [3] propose that the unserved energy be valued on the basis of the costs to the users of maintaining back-up generation and voltage regulation equipment. This is based on the idea of a profit maximizing firm, which in the margin expects to gain from the self-generated kWh the same as it would loose from a kWh shortage in public supply. The problem with this approach is that back-up generating equipment depends to a large extent on past quality of service. As a result, the worse the supply in the past, the more emergency equipment and the greater UEC would be under this approach. However, in reality the better the quality of service, the smaller the expectation of an interruption and less back-up generation. Thus, UEC is higher when users are not expecting an interruption, since they have less or no protection at all. Sanghvi [41] distinguishes between the short and long-term UEC. Long-term UEC in a low-quality system is less than short-term, since expectations induce users to protect themselves against poor service reliability.

Despite the limitations alluded to, the DC method offers the best possibilities, when supplemented with information about users' back-up equipment, and complemented with estimates regarding the effects on the economy of the drop in users' incomes. As the DC approach is applied and its results known, the utility and the users gain experience. This avoids the initial mistakes, and reduces the implementation and interpretation costs.

In the context of PLRP for technical losses, the type of reliability improvements we are interested in are those at the distribution level. At this level interruptions are generally sudden, except in the case of planned maintenance. The reliability benefit is estimated in stages. First, the physical improvement in supply resulting from the project is estimated, in terms of: (1) frequency of shortages, (2) their average duration, and (3) the unserved energy. This is the estimate of the unserved energy (EUE) which will be supplied if the project is implemented. Second, the users affected by the energy shortages are examined and the consequences valued. In this second stage the UEC is calculated in economic terms for each user type: industrial, residential, commercial, etc. Finally, the reliability benefit during the life of the project is estimated by bringing together EUE and UEC6/.

C. Benefit of Voltage Improvements

PLRP frequently reduce voltage fluctuations, improving the quality of supply. A survey is too expensive for estimating this benefit. A simpler and more economical approach is required. The proposed approach is based on users' willingness to pay (WTP) for the increase in energy consumption attributable to better voltage regulation.

How much would users be prepared to pay to achieve this quality improvement in supply? The WTP is the area below the users demand curve for electricity. Graph 1 depicts the demand curve without the project. At price t_{wo} consumption is D_{wo}. With the rehabilitation project, the voltage improves and more energy is supplied at each price, displacing the demand curve to the right. Thus, consumption at price t_v increases with the project to D_v.

6/ For a detailed explanation of calculating outage costs using the survey method, see Gutiérrez [17].

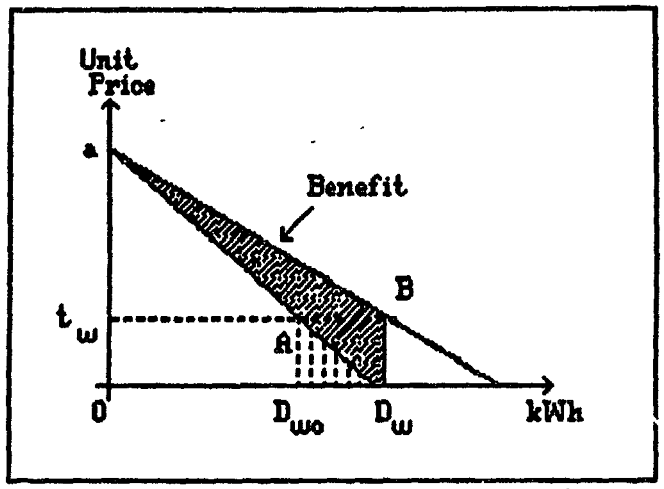

Figure 1: Demand Curves With and Without Better Voltage Regulation

The benefit (B) of the voltage improvement is the difference between WTP_v and WTP_{vo}. WTP is the energy sales (S) and the consumer's surplus (CS). Assuming a linear demand curve, sales without the project are:

$$S_{vo} = t_{vo}\ (D_{vo}).$$

The consumer's surplus is:

$$CS_{vo} = \tfrac{1}{2}(a-t_{vo})\ D_{vo}$$

and WTP is therefore:

$$\begin{aligned} WTP_{vo} &= S_{vo} + CS_{vo} \\ &= t_{vo}\ (D_{vo}) + \tfrac{1}{2}(a-t_{vo})\ D_{vo} \\ &= \tfrac{1}{2}(a+t_{vo})\ D_{vo} \end{aligned} \qquad (D.1)$$

WTP with the project is

$$WTP_v = \tfrac{1}{2}(a+t_v)\ D_{vo} \qquad (D.2)$$

The increase in energy consumed as a result of better voltage regulation "Q_v" is obtained from market demand forecasts and from circuit studies. D_v is the sum of D_{vo} and Q_v. The demand curves can be estimated from these values:

$$t_{vo} = a-b_{vo}D_{vo}$$

and $\quad t_v = a-b_vD_v$

The known points on the demand curves are D_{vo} and t_{vo} for the situation without the project, and D_v, t_v with the project. The demand curves' coefficients remain to be estimated: the intersection value "a" (the same for both curves), and the slope of each curve, "b_v" and "b_{vo}" (note that since $t_{vo} = t_v$, $b_{vo}/b_v = D_v/D_{vo}$).

These coefficients can be estimated from the price-elasticity of demand (ϵ). Once ϵ is calculated, a ceteris paribus price-demand equation is assumed and the values of the coefficients derived. In other words, all other demand variables are assumed constant, varying only prices and quantities. The slope of the linear demand equation is given by:

$$b = dt/dD$$

since

$$\epsilon = (dD/dt)(t/D)$$

$$b = (1/\epsilon)(t/D)$$

The intersection is calculated as

$$a = [t(\epsilon-1)]/\epsilon$$

Once the coefficients are determined for both situations (with and without the project), the benefit of the voltage improvement is easily estimated. This benefit is the difference between WTP_v and WTP_{wo}, up to the consumptions D_v and D_{wo}, respectively. In other words, B is the difference between the areas $OaBD_v$ and $OaAD_{wo}$ in Graph 1.

$$B = WTP_v - WTP_{wo} \qquad (D.3)$$

and substituting (D.1) and (D.2) in (D.3)

$$B = ½(a+t)[D_v-D_{wo}]$$

The net benefit (NB) of the improvement in voltage regulation is the benefit less the cost of supplying the additional energy. This cost is the marginal cost (mc) times the additional energy permitted by the project (Q_v):

$$NB = B - mcQ_v$$

Repeating, the relevant mc is equivalent to the marginal generation cost plus the marginal cost of transmission and subtransmission in the tension level prior to the tension in which the user is being supplied.

It should be noted that in a large number of developing countries tariffs are out of line with the marginal costs of supply. Different users are frequently subsidized for equity reasons and/or political considerations, or assumedly because it provides economic incentives to some industries. Also, subsidies frequently occur in inflationary situations because of tariff adjustments lags. When the marginal cost is higher than the tariff, the project may not be profitable for the utility, but convenient for the economy. This can be seen in graph 2. The rectangle, indicating the cost of supplying the additional demand $mc(D_v-D_{wo})$, is larger than the revenue generated by the project, $t_v(D_v-D_{wo})$.

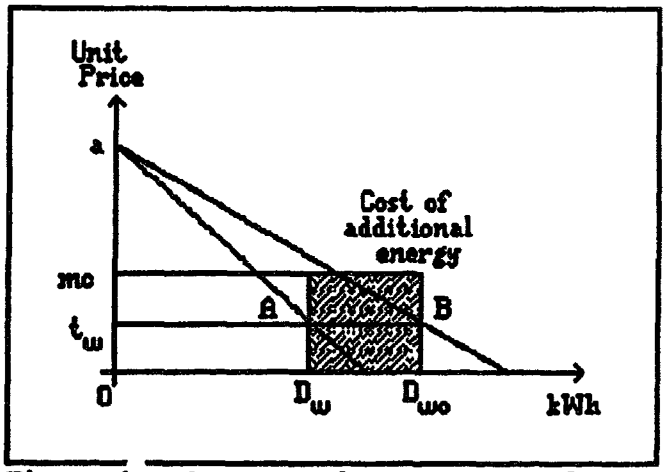

Figure 2 Costs and Revenues of the Additional Energy

IV. NON-TECHNICAL LOSSES

A. Causes of NTL

Before examining revenue improvement projects, certain points should be cleared up. NTL are a form of consumption which is not charged by the utility. Thus, the reduction of NTL constitutes a major objective for electrical utilities, because the utility has to generate more (which is costly), and receive less revenue (which is inefficient). Non-technical loss reduction projects (NTLRP) vary according to the type of NTL. The make-up of NTLRP depends on the type of losses and the characteristics of the electricity supply system.

When energy theft and fraud are not quickly controlled, the practice rapidly spreads and becomes socially acceptable. Fraud becomes a game in which everybody wants to participate, a politically acceptable way of subsidizing low-income groups, and a practice in which better-off users increasingly participate. Where theft is deep-rooted, more investment is needed in distribution equipment relative to expenditure on meter reading, billing and collection.

In some countries, newspapers advertise illegal connections at modest rates. Private retailers--illegally connected to the grid-- offer power at rates below official tariffs. Personnel for meter reading offer customers lower readings in exchange for gratuities, etc. In such situations eliminating fraud becomes unpopular and difficult. Normal administrative measures, police activities and disconnections of illegal users are rapidly outflanked by new forms of fraud and reconnections. In such cases, the unit costs of NTLRP are higher than when this practice is rapidly corrected. NTLRP need to be complemented with expensive technical fixes, so as to make it as difficult as possible to commit fraud; examples are duplex and triplex service drops, meters in strongboxes and/or mounted on posts, etc.

Unlike projects to reduce technical losses, the user's location in the circuit is not relevant, what matters is the nature of consumption. This is so, because the type of user determines the level of consumption (benefits) and the measures to fight fraud (costs). NTLRP may include various users connected to different circuits and dispersed over a wide area, but with similar consumption patterns. An example would be a poor residential neighborhood (or an industrial zone or commercial center, etc.) supplied by different circuits, but forming part of the same project. The project scale is defined by the number of users regardless of their location in the system.

It is convenient to differentiate users according to tariff types (residential, commercial and industrial), and then subdivide them according to consumption levels (high, medium and low). This breakdown is appropriate because the reduction in consumption (from unpaid to paid consumption) varies according to the type of users involved, and within each users' category, according to income level. For instance, the decline in NTL is greater for higher-income than for low-income neighborhoods. Therefore, projects aimed at reducing NTL in circuits with higher average consumption levels are more profitable and should be implemented first. Furthermore, the decline in consumer's surplus as a result of the reduction in fraud is not as serious, from an equity point of view, for the higher income levels than for the lower income groups.

Hence, it is important to determine the origin of the losses to design optimum PLRP. NTL come from two sources: users' fraud, and inefficiency of the utility. The fraudulent causes are:

1. illegal connections,
2. tampered meters,
3. deceitful under-reporting of true consumption by personnel of the utility, and
4. resale to third party users of energy by customers with fixed tariffs (no meters).

The greatest share of NTL in LDCs is due to theft (stolen electricity by the user, first cause) and fraud (underpaying electricity consumption, last three causes), frequently accounting for three quarters of NTL. Inefficiency losses stem from technical imperfections in the meters or from management carelessness and/or inefficiency; for example:

1. inaccurate reading (or not readings at all) of meters and estimation of consumption;
2. incorrectly connected or defective meters;
3. unregister users;
4. fixed-charge users with greater consumption than the contracted for;
5. non-measured public consumption (such as public lighting and other public facilities in several countries);
6. billing and collection deficiencies; and
7. discrepancies in power generated, transformed and recorded at consumption.

The common feature to NTL is that the tariff on marginal consumption is zero.

NTLRP are designed to fight theft and fraud (first four causes) and inefficiency consumption (second group of causes). This is done through a variety of measures, such as regularization of users, substitution and installation of proper hook-ups and equipment (leads, connectors, and meters), introduction of new systems of meter reading, billing, collection and surveillance.

These projects may include equipment, systems, and procedures such as:

1. new transformer casings, service drops, connections and meters, as well as calibration equipment;
2. computing hardware and software for billing and collection;
3. design and introduction of procedures to penalize illegal users;
4. procedures for meter reading, billing, collection and personnel management of meter readers (such as personnel rotations), and
5. personnel training, supervision and surveillance.

B. Benefits of NTLRP

NTLRP vary according to the type of benefits. There are two main benefits. The first one is the resource savings in generation, since a share of the energy previously consumed free of charge ($t_{wo} = 0$), will no longer have to be produced. The second benefit consists of the increase in WTP since the project might avoid higher tariffs, or lead to a higher demand level. Even though, the first benefit generally predominates in most projects, the second benefit is frequently present, which, when important, should be explicitly estimated.

Not all the previously unpaid consumption will cease to be generated, part will continue to be supplied with the project, but paid for at the tariff rate for that user, t_w. Thus, it is necessary to determine the reduction in the consumer's surplus resulting from the price increase. When this type of NTL predominates, the electrical utility obtains significant financial benefits: firstly, from the reduction in operation costs associated with the lower output level, and secondly, from the added sales revenue.

The increase in WTP can result from a potential reduction in tariffs and/or an improvement in long term reliability. On the one hand, when existing users subsidize unpaid consumption, the reduction in NTL benefits the former by preventing unnecessarily high tariffs. On the other, when the utility covers part (or all) of the cost of NTL, the improved financial position resulting from the loss reduction and the increase in sales revenue, enables it to keep investments and maintenance work on schedule, thereby preventing unnecessary cost and tariff increases. (As already indicated, this benefit also accrues from projects to reduce technical losses.)

C. Cost/Benefit Analysis

From an economic point of view users who consume more than what they pay for (whether for reasons attributable to them, such as fraud and theft, or not), are receiving a benefit equal to what they would be willing to pay for this free energy (WTP_{wo}). With the project, the reduction in WTP becomes a cost, i.e. the loss of the consumer's surplus. Likewise, the supply cost savings associated with the elimination of NTL is a benefit attributable to the project. Therefore the benefit for the economy of unpaid consumption (B_{wo}) can be expressed as:

$$B_{wo} = WTP_{wo} - mcD_{wo}$$

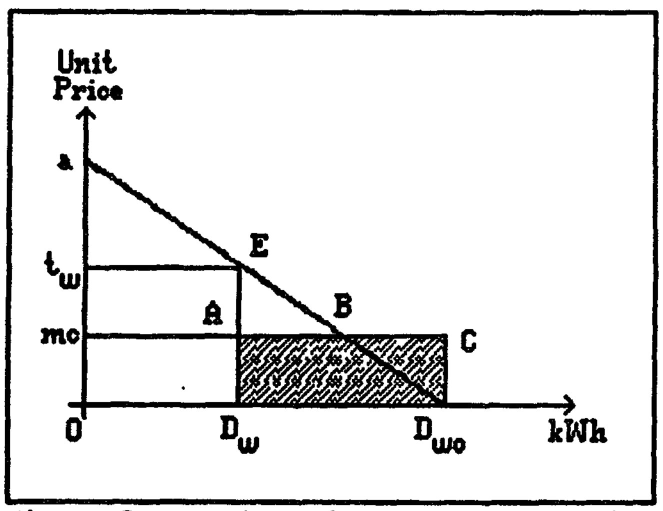

Figure 3: Savings due to the Reduction in Unpaid Consumption

The purpose of the project is to charge for the unpaid consumption (D_{wo}). However, not all of the unpaid electricity that was consumed will be demanded with the project, since the price-elasticity of demand is higher than zero. Therefore, a price increase from 0 to t_w reduces quantity demanded from D_{wo} to D_w. The benefit with the project (B_w) is expressed as

$$B_w = WTP_w - mcD_w - C_p,$$

where C_p = project costs.

and the net benefit (NB_v) of the project is

$$NB_v = B_v - B_{wo}$$
$$NB_v = mc\ [D_{wo} - D_v] - [WTP_{wo} - WTP_v] - C_p$$

[Project Net Benefit] = [Resource Savings] - [Decline in consumer's surplus] - [Project costs]

We know that WTP_{wo} is larger than WTP_v, since the energy consumed falls from D_{wo} to D_v as a result of the project. Therefore, the first term of the equation constitutes the benefit, the savings in resources resulting from a decline in NTL. While the second term is the cost, the reduction in consumer's surplus. The final term is the discounted project costs (investment, operations-maintenance, billing, collection, etc.). It should be noted that all the project flows are expressed in present value terms at the opportunity cost of capital.

The benefit in figure 3 is the rectangle D_vACD_{wo}, the savings resulting from the reduction in consumption when previously unpaid consumption begins to be paid. The cost is the decline in WTP equal to the triangle D_vE_{wo}. The project is desirable when

$$D_vACD_{wo} > D_vED_{wo} + C_p$$

that is, when the area $D_{wo}BC$ is larger than the triangle AEB plus the cost of the project. It is worth noting that, for a NTLRP not to show an acceptable return, the cost savings would have to be negligible and/or the tariff be much higher than the marginal cost. In graph 3, Cp would have to be zero so as to be indifferent between doing or not the project, since the tariff is higher than mc. However, this case is less frequent in the real world, than the case of tariffs below supply costs. Consequently, the possibility that the decline in the user's surplus would be larger than the resource savings is remote.

When the tariff is set according to marginal cost, the net benefit from the project is the shaded triangle in the graph below, less the project costs. This is the optimal situation, where the costs of the service are covered and the consumer's surplus is maximized. The reduction in the surplus of the irregular consumer is equal to half of the resource savings; in other words,

$NB_w = mc(D_{wo}-D_w) - \frac{1}{2}[t_w(D_{wo}-D_w)] - C_p$

and as $mc = t_w$, then

$NB_w = \frac{1}{2}\ mc(D_{wo} - D_w) - C_p$

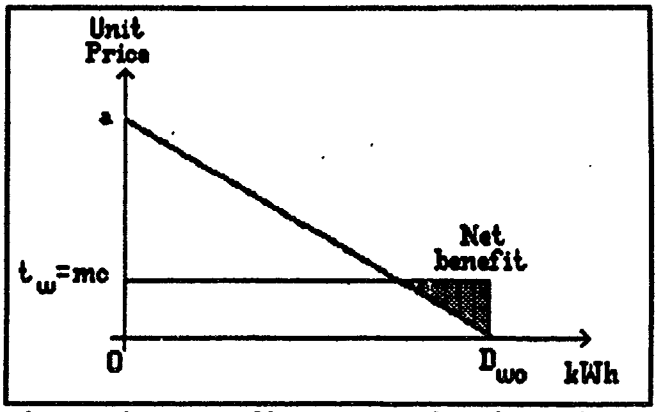

Figure 4: Benefit From Reduction of NTL When Tariff Equals Marginal Cost

When the tariff is subsidized, the project benefit is smaller than in a situation of marginal cost pricing. The resource savings associated with a reduction in consumption from D_{wo} to D_w is smaller by the shaded triangle in the figure below. In this case the resource savings is twice the reduction in the consumer's surplus plus the subsidy (the difference between the marginal cost and the tariff multiplied by the reduction in consumption). This can be expressed as follows:

$mc(D_{wo}-D_w) = t_w(D_{wo}-D_w) + (mc-t_w)(D_{wo}-D_w)$

The net benefit from the project (NB_w) is the resource savings less the reduction in the consumer's surplus and the project costs,

$NB_w = mc(D_{wo}-D_w) - \frac{1}{2}t_w\ (D_{wo}-D_w) - C_p$

Substituting the term mc $(D_{wo}-D_w)$ and manipulating the equation algebraically, we arrive at the following expression

$= \frac{1}{2}t_w(D_{wo}-D_w) + (mc-t_w)\ (D_{wo}-D_w) - C_p$

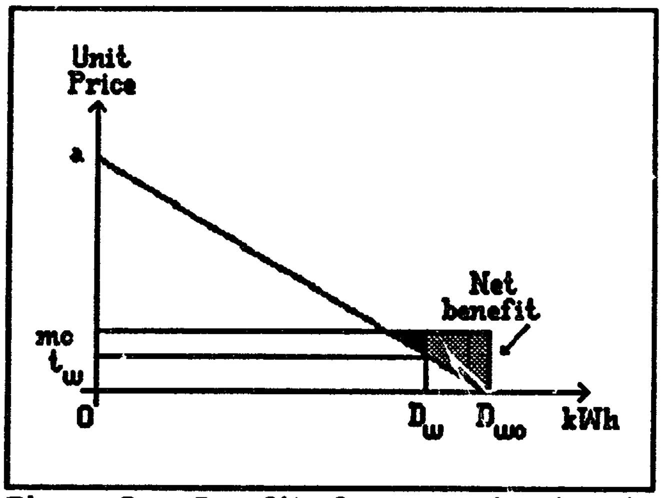

Figure 5: Benefit from a Reduction in NTL when Tariff Below Marginal Cost

Finally, in the case of a tariff higher than the marginal cost of supply, the reduction in consumer's surplus for a move from a price of zero to one higher than the cost of the service is, as might be expected, larger than in the two previous cases. However, the over-pricing is not normally as high as to make uneconomical NTLRP; i.e., a reduction in consumer surplus larger than the decline in costs. Figure 6 illustrates this situation. As can be seen, to the left of the optimum point B the resource savings, $mc(B - D_w)$, is smaller than the reduction in the willingness to pay for this energy by the area $\frac{1}{2}(t_w - mc)(B -$

D_w). To the right of optimum point B, the resource savings $mc(D_{wo} - B)$ is twice the reduction in the consumer's surplus. The net benefit of the project is given by the shaded area.

B. Calculating the Benefit and the Economic Cost

Resource savings are estimated from the reduction in consumption, which in turn is estimated from the known data on marginal cost and the unpaid consumption D_{wo}. The consumption D_w, once the users are regularized, is calculated from the demand curve. In the case of clandestine connections, the tariff without the project is zero ($t_{wo} = 0$). The linear demand curve takes the following form:

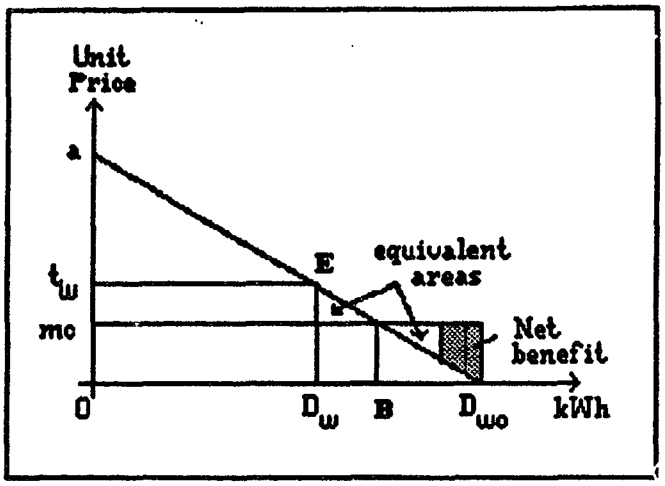

Figure 6: Benefit from Reduction of NTL when Tariff Above Marginal Cost

$$t = a - [a/D_{wo}]\ D$$

where

$a = [t_w\ (\epsilon - 1)]/\epsilon$
t = tariff ($t = 0, \ldots, mc, \ldots, t_w, \ldots, a$);
D_{wo} = fraudulent consumption, and
D = demand at price t.

If a meter has been tampered so that it records only a fraction of true consumption, or in the case of a by-pass, where part of consumption (D_x) is paid at the current tariff (t_w) while the remainder (D_r) is not paid for, the relevant tariff consists of the weighted average of both prices. In both cases the relevant tariff without the project is higher than zero ($t_{wo} > 0$).

$$t_{wo} = (t_w D_x)/(D_x + D_r)$$
$$= t_w\ (1/D_r).$$

The demand equation in this case is as follows:

$$t = a - b\ D$$

where

$$b = (1/\epsilon)\ (t/D).$$

Once the demand curve is estimated, the consumption of the regularized users is calculated by replacing t with the with-project tariff t_w and solving for the unknown quantity D_w. The savings can then be calculated as the product of the marginal cost of replacing the connections mc and the reduction in consumption ($D_{wo} - D_w$).

The reduction in WTP (WTP_{wo} - WTP_w) also varies according to the type of unpaid consumption, i.e. whether entirely free or partly paid for. If the tariff is null (t_{wo} = 0), the loss of consumer surplus CS is:

$$CS = \frac{1}{2}\ t_w\ [D_{wo} - D_w]$$

When the tariff is greater than zero ($0 < t_{wo} < t_w$), the reduction in CS is calculated from:

$$CS = \frac{1}{2}\ [t_w - t_{wo}]\ [D_{wo} - D_w].$$

C. Unpaid Consumption with Improved Reliability

In cases where the consumer receives a low-quality service, the result of regularizing his situation and incorporating him into an upgraded network may represent an improvement and a net increase in his consumption, rather than a reduction. In balance, the increase in demand in response to an improvement in the quality of supply may offset the reduction in consumption resulting from the price elasticity of demand.

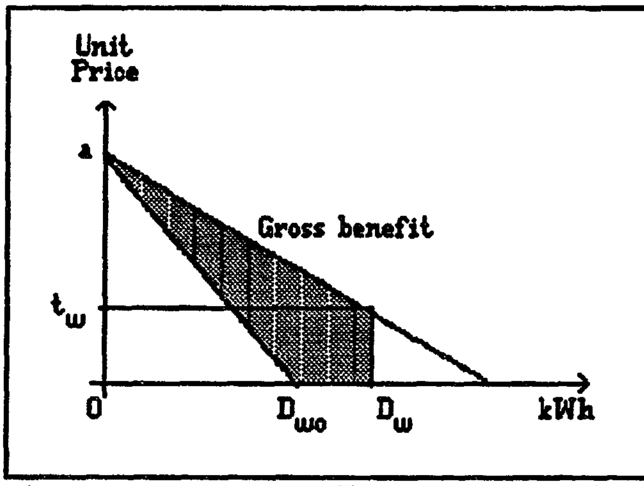

Figure 7: Benefit to Previous Clandestine Users From Improved Quality of Service

Residents in low-income neighborhoods often connect themselves to a secondary circuit with their own wires, frequently of different sizes, the joints are done manually. The wires are taken to their homes, in some cases several blocks away, by hanging them on walls, trees, roofs, tall poles and whatever is at hand. Other residents connect themselves on the original wires, becoming for all practical purposes informal secondary circuits. Their condition making them not only a constant danger but also contributing significantly to technical losses. In these circumstances, the voltage level is very low. In many cases, turning on an appliance in one of the user's residence often reduces significantly the voltage of the other consumers in the circuit. In other cases users cannot turn on any electrical appliance during the hours of maximum demand.

The benefit to the clandestine user is the shaded area between the two demand curves shown in Figure 7. The low-quality fraudulent consumption corresponds to D_{wo} at a null tariff. Consumption increases to D_w as a result of the quality improvement, despite the fact that a tariff t_w is now being charged. The benefit can be determined by calculating the area between these curves, using the same procedures described previously.

The net benefit is determined by subtracting from the benefit the cost of the incremental energy, $mc(D_w - D_{wo})$. Considering the three previous cases (i.e.: $mc = t_w$, $mc > t_w$, and $mc < t_w$), the utility is in the most favorable situation when marginal cost pricing is the rule (Figure 8), where the difference between WTP and the cost of resources is at its maximum. In other words, the equation

$$O_aBD_w - OmcBD_w = t_waB$$

reaches a maximum when $t_w = mc$.

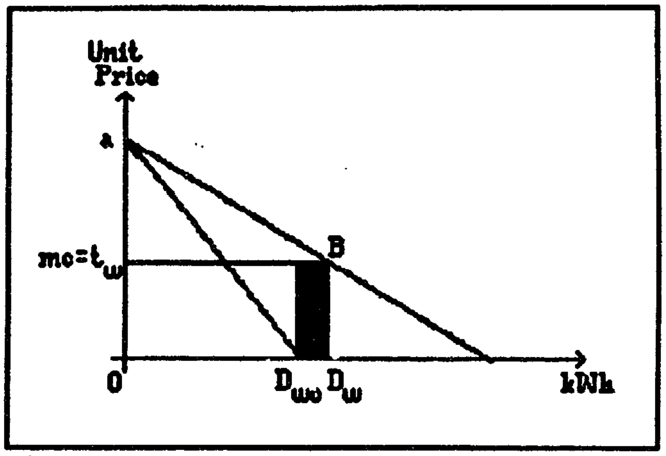

Figure 8: Cost of Additional Energy From Improved Quality of Service When Tariff Equals Marginal Cost

When the tariff is subsidized, the improvement in quality of service produces a relatively larger increase in the cost of supply than the increase in consumer's surplus. The dark triangle to the right of and above the demand curve in figure 9 shows what the company loses for being in a suboptimal situation, i.e., from charging less than its production costs.

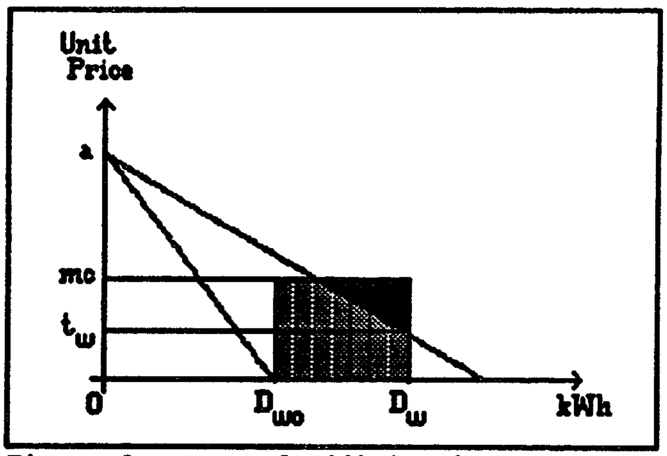

Figure 9: Cost of Additional Energy From Improved Quality of Service When Tariff Below Marginal Cost

Finally, when the tariff is higher than the cost of supply, the increase in demand as a result of the improvement in service quality will be smaller than in the previous cases, and, depending on the magnitude of the over-pricing, the with-project demand D_w may be smaller than D_{wo} (see the graph below). Therefore the change in consumption of illegal users when their situation is normalized, under an improvement of quality, varies inversely to the differential between tariff and marginal cost.

It should be pointed out that with the project, not all clandestine users are going to connect legally to the grid during the first year after completion of the project. Some will during the first year, others during the second and so on. Similarly their consumption when they have to pay for it will be lower than when they were not paying for it. The increase in consumption due to a quality improvement affects only some consumers, i.e. the better off.

V. CONCLUSIONS

The purpose of this paper was to present a methodological framework for the economic analysis of PLRP.. We therefore describe the methodology for calculating the benefits of such projects, distinguishing between technical and non-technical losses. The main benefits of PLRP are first, the savings in costs of system operation and expansion, and second, the improvement in service quality. The project may also enable a higher level of demand to be met, but generally this is a secondary benefit. The principal economic benefits of NTLRP (non-technical loss reduction projects), also known as revenue enhancement projects because of their positive effects on the company's finances, are the resource savings and the improvement in the quality of supply. An additional benefit of both kinds of project is the increase in demand as a result of tariff reductions in relation to the without project situation.

These benefits are the result of the following effects: (a) a reduction in illicit consumption and an increase --larger than the reduction-- in paid consumption; (b) more efficient meter reading, billing and collection; (c) a reduction in technical losses as a result of the net reduction in consumption and the reduction of NTLs; (d) an increase in sales revenue and consumer's surplus as a result of quality improvements and the reduction in marginal costs.

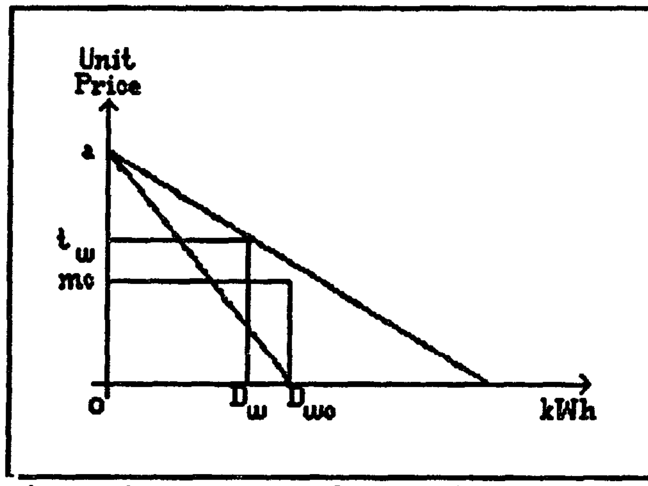

Figure 10: Cost of Additional Energy From Improved Quality of Service When Tariff Above Marginal Cost

No electric utility in the world can sell all of the energy produced. The costs of attempting to reduce losses to the physical minimum would exceed the benefits. There is always an acceptable economic level of losses. This level varies from country to country, depending on supply conditions and the structure of relative prices. The level is reached when the cost of reducing losses by 1 kWh is larger than the long-term marginal cost of supplying it. In most cases this level is around 10% of total requirements. Higher levels generally represent an unnecessary use of resources and indicate inefficient past policies, especially as regards management and tariffs. In all the cases examined, the optimum operating level occurs when tariffs are equal to the marginal cost, the latter including future expenditure on maintaining the system in good condition. If tariffs had been established on this basis, they would probably be no need to invest in projects to reduce losses.

In the final analysis, PLRP are nothing more than corrective measures required by the lack of preventive maintenance and adequate policies in the past. Although it is difficult to speculate about what would have happened if other conditions had prevailed, there is no doubt that when losses are reduced to an acceptable level and appropriate tariff, planning, and maintenance policies are in place, there is no need for such projects.

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LOSSES CONTROL IN ELECTRIC SYSTEMS

GENERAL CONCEPTS AND DEFINITIONS

By

Dr. Renato Cespedes G.

1. Introduction

The growing costs of investments in the expansion of electric energy power systems and of its operation has motivated the need of increasing the efficiency of the electric power systems in the region.

One of the means to reach a higher efficiency is to reduce the electric losses. The electric losses of the Latin American and Caribbean countries are, in general, higher than those observed in other developed countries and in consequence it has been concluded that it is imperative to reduce losses.

Some studies have pointed out that reducing a Kilowatt of losses has a higher benefit to cost ratio than installing a new source to produce the same power.

Several studies in various countries have been carried out in order to solve the "losses problem". This problem has several aspects such as:

- From a general economy point of view of a country it is considered that the losses is an inefficiency of the system but that only a part of the losses is really dissipated energy being another part energy that is effectively used but not paid to the utilities. In this respect more emphasis is given to the so called technical losses that will effectively reduce peak load demand and will reduce operation costs.

- From the utilities point of view the losses problem is more related to a problem of loss of revenue and therefore it is focused with more emphasis to the "financial losses" (non-technical losses) and to the short term and fast recovery of investments that reduce the losses.

- From the users point of view the problem is considered more a problem of the utility alone and since internal losses of the end users are in general not measured, no attention is put to a "rational use of the energy".

The losses problem is in general a complex one that has several aspects to be solved, including:

- Determination of the losses sources, causes and assessment of the losses level for each one of the causes for the actual system.

- Determination of optimal long run economical losses levels in order to identify areas where potentially loss reduction actions could be more effective.

- Identification of the losses control actions that have a higher benefit to cost ratio. Classification of these actions and establish a "Losses Control Program".

In this document the losses problem is presented in a general form with emphasis in the identification of the different causes of losses and the analysis of the statistics that are related to energy losses with the objective to define common points of interest to all countries in the region regarding this problem.

This document presents some aspects already discussed in the "Simposio Latinoamericano de Perdidas Electricas" of Bogota Colombia, October 1988, which is part of the losses reduction program of the Organization Lationoamericana de Energia, OLADE.

2.0 Demand and Losses

2.1 Losses Amounts

In order to gain insight into the losses problem this section presents some statistics of losses taken from different sources.

Figure 1 presents the evolution of the electric losses of a company. This company includes generation, transmission (220 and 115 kV), subtransmission (115, 57.5, 34.5 kV) and distribution (most at 13.2 kV for primary circuits and 440 and 208 volts from secondary distribution). It generates internally approximately 60% of its demand of 1300 MW.

The figure presents the evolution of the demand and the total energy losses during the period of 1976 to 1986. They grew from 13% to 24.5% of the demand with an annual average growth rate of 12.8% while the demand increased at an average rate of 5.6% during the same period.

For comparison purposes the "square of the demand" curve is also included in Figure 1, considering the demand square for each year and normalized so that it matches with the losses value at the initial year. It can be observed that the losses grew almost at the same rate as this curve. Since most of the losses change with the square of the current it can be considered that this would reflect a system with almost no reinforcement.

Unfortunately, the losses breakdown in technical and nontechnical losses is not known for the same period. The company report establishes that for 1976 the technical losses were of 11.2% and 6% of non-technical while for 1988 the same were of 11.2% (constant losses for all this period!) and 13.2% respectively.

The previous data illustrate the need to know with at least a fair precision the different losses amounts in order to direct adequately the available losses reduction resources.

2.2 Comparison of Different Losses Levels

Table 1 presents, as an example, the losses reported by three different sources named Colombia 1978, Cadafe and "Ideal". This last one corresponds to the World Bank report source from which the column "Maximum tolerable) has been also extracted. Since not all the sources present the data in the same way some adjustments were made in order to have comparable data. For instance, for the Cadafe case the average values of the presented range were selected; also for Cadafe and the "Ideal" case the percentages were corrected to present them with respect to the demand instead of with respect to the generation.

The comparison of the different data allow to establish the following conclusions:

- The "ideal" amount of losses (assuming that this value is applicable to the other cases) is much lower than the 12.6% of the Colombian case and the 10% of the Cadafe case.

- It can be noted that the losses distribution among the different voltage levels between the "ideal" and the other cases. In the Colombia and Cadafe case the higher proportionally losses are due to distribution feeders and transformers. Figures 2, 3 and 4 illustrate these results.

The previous data do not try to establish that the "ideal" case shall be considered as a target for the losses level of a country but it stresses the importance of comparing the losses levels of different countries together with the information of experiences, standards, design considerations that are applied in some countries and that contributes to have low losses levels. This can be considered by others in order to apply corrective actions correspondingly.

Finally, the losses reduction programs cannot be generalized. The technical literature present cases in which the benefit to cost ratio arrives to as high as 15/1 for losses reduction actions. However, no generalization can be made based on other systems results and each case shall be analyzed independently in order to arrive to the correct solutions for each case.

3.0 Classification of Losses in Electric Systems

3.1 Introduction

An electric power system is integrated by a complex set of generators, high voltage transmission lines, power transformers, distribution feeders, etc. Each element through which an electric current is circulating or is energized, that is connected to the power source like the case of an energized transformer, contributes to increase the system losses.

The power (or energy) losses can be defined for each component of the system as the difference between the input power (or energy) minus the output power (or energy) of the component. The losses are in consequence the result of a reduced efficiency of the transport or transformation of a system element.

The instantaneous efficiency of each system component can be defined in terms of the input and output power. In the same form the efficiency over a time period can be defined in terms of the input and output energy. The following relation can be established:

Losses (%) = 100 - Efficiency (%) (1)

The previous relationship is applicable to power or energy according to the utilized efficiency being the losses less when the efficiency approaches its limit of 100%.

It is important to recognize that in general all the system elements have different efficiencies which may change with the operating conditions. In addition, only for design the losses of each element are not considered independently being it necessary to group the losses according to causes and according to the sources that produce the losses.

The previous conducts to the need of classifying the losses with several purposes including:

- The evaluation of the losses by appropriate methods applicable to each case.
- The geographical location of the losses to establish the contribution of each part of the system to the total system losses.
- The contribution of the components at different voltage levels to the total losses.
- The contribution of elements with different functions (transport, transformation, etc.) to the losses.

3.2 General Classification

3.2.1 Power Losses

As mentioned before the power losses are those that are produced instantaneously in the power system. Figure 5 illustrates the demand curve and the corresponding demand losses.

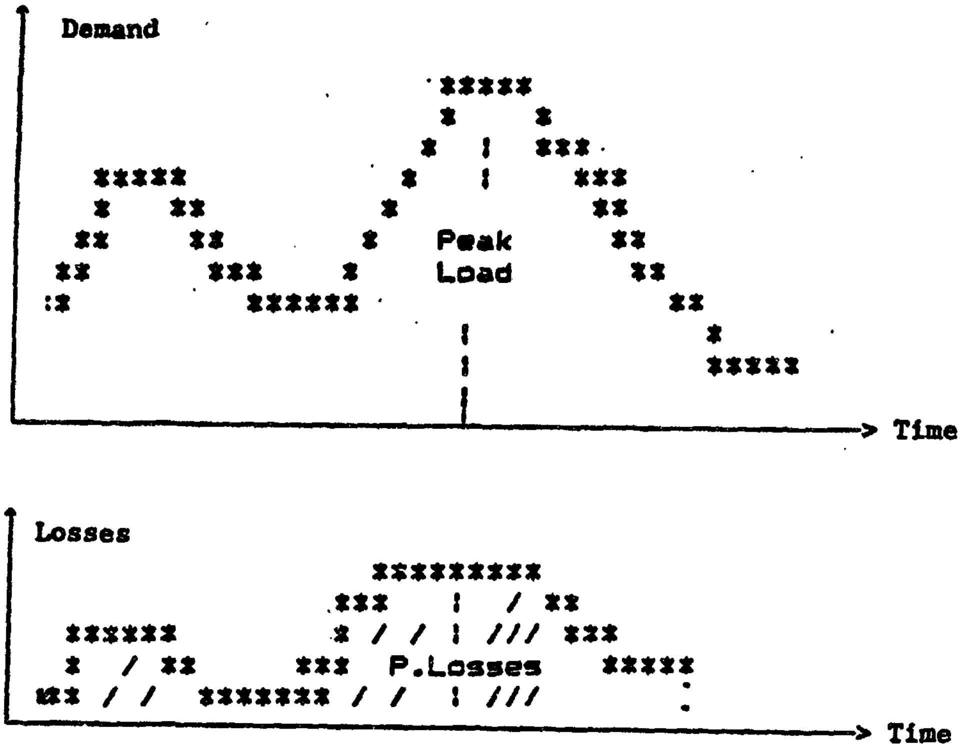


Figure 5

The generation of the power system shall be programmed to supply the demand and the losses:

$G(t) = D(t) + LP(t)$

where

$G(t)$ is the generation at time t

$D(t)$ is the demand at time t

$LP(t)$ are the power losses at time t

It is evident from the previous equation that the losses increase the system load and require additional generation. In other terms a reduction of losses reduce the total load and if this loss reduction is performed at the system peak, investments to feed the total load can be postponed.

The power system losses can be classified in the following form:

By type	By cause	By time	By variation	By site
-Technical Losses	-Corona -Joule effect -Eddy currents and histeresis	-Peak losses -Off peak losses	-Load dependent -Fixed	-By company -By zone or region

3.2.2 Energy Losses

Energy losses can be expressed in terms of power losses in the following form:

Le = Int (LP(t)) dt = Ave(LP(t)) T (2)

where

Le are the energy losses in the period T

Lp(t) are the power losses as function of time t

Ave ( ) indicates average

Int ( ) indicates integral

Being the eneregy equivalent to useful work, the energy losses is that part of the energy that is not used or is dissipated in the system (Joule effect for example). The following equation can be deducted from equation (1):

Generated energy = Demand energy + Energy losses (3)

In a utility the generated (or received) energy and the demand (or supplied) energy are measured by means of energy counters located at the different points where the energy is the generation minus the demand and should be the same as those that could be calculated from equation (2). In case that the energy losses are greater than the calculated ones this additional loss is also an "energy loss" for the utility although it is energy that was effectively delivered. This type of losses called non-technical losses cause financial losses to the utilities since the service provided by the utility is not paid adequately by the user.

Considering the previous concepts the following classification can be established for the energy losses:

By type	By cause	By time	By variation	By site
-Technical Losses -Non technical	-Corona -Joule effect -Eddy currents and histeresis	-Losses of period: daily monthly, ect.	-Load dependent Fixed	-By company -By zone or region

3.3 Technical Losses

3.3.1 By function of element

- Transportation losses

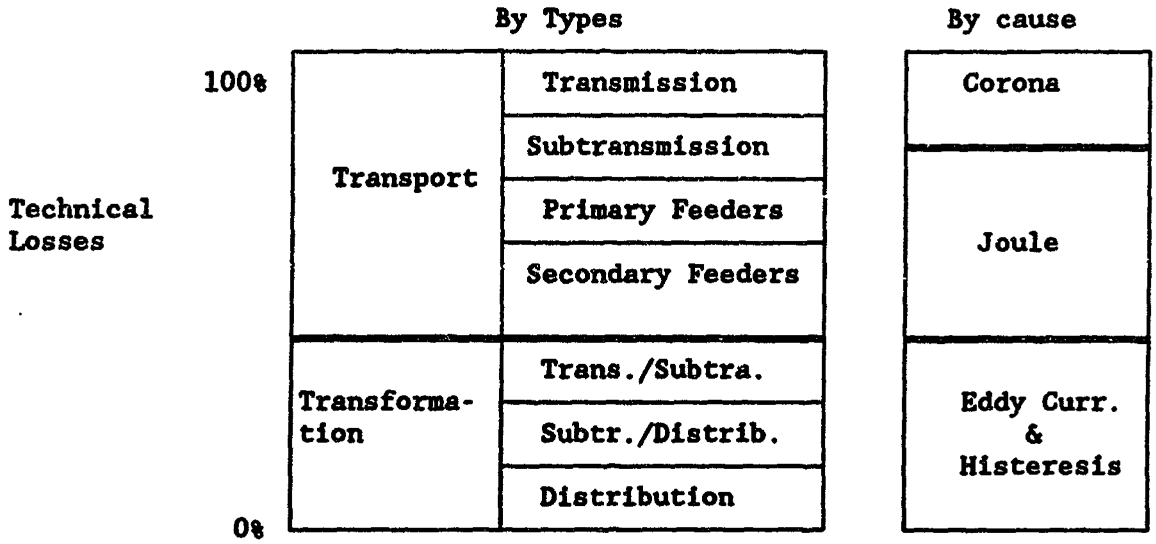
  - In transmission lines
  - In subtransmission lines
  - In primary distribution circuits
  - In secondary distribution circuits

- Transformation losses
    • In transmission/subtransmission
    • In subtransmission/distribution
    • In distribution transformers

3.3.2 <u>By losses causes</u>

• Corona effect losses
• Joule effect losses
• Eddy currents and histeresis

3.3.3 <u>Summary Table</u>



3.4 <u>Non Technical Losses</u>

For the non technical losses the following classification is proposed:

- Consumption of users that are not registered by the company or theft:

  Comprises all the direct connection of the users of energy to the power system without having subscribed a contract or agreement with the utility for the energy use. In this group are also included those users that had a contract with the utility but that having been suspended, reconnect themselves to the network without permission. This type of users have of course no energy measurement.

- Energy measurement error of subscribers with energy meters.

  Comprises all those measurement errors of meters, reading of counters and billing of subscribers excluding the cases of equipment adulteration. In these losses those due to the non-simultaneous measurement of counters are included.

- Error of estimated consumption of subscribers without energy meter.

  Corresponds to all those subscribers that for any reason are billed by an estimation of the consumed amount. Includes those cases of temporary users which the utility decides to bill without a meter.

- Energy theft by utility subscribers.

  Comprises all those cases of which the user, being a utility subscriber, adulterates the measurement equipment or takes the energy directly.

- Error in the own utility consumption.

  Corresponds to the energy used by the utility but not meterd. Includes substation auxiliaries, street lights, etc.

4. Energy Statistics

One important aspect related to energy losses is the statistics that reflect the energy produced and sold over a certain period. The statistics are normally presented as energy balances and included in the annual report of the utilities. This section presents the various aspects regarding energy balances that are related to energy losses.

Figure 6 presents a typical energy balance in a graphic form. This balance does not include the generation losses since it takes as input the gross generation at generators terminals. Also it does not consider the end use of energy at the user level.

4.1 Particular Considerations

(a) The generation of the electric energy is a process that has losses at the production level. In effect, the thermal generation and in a lesser extent hydrogeneration requires energy for the auxiliaries. This implies that in order to reflect the efficiency of the transportation, transformation and distribution of the electric energy, the energy used by auxiliaries be subtracted from the generation which is the net generation of the system.

The previous will alow to compare on the same bases systems that have hydro and thermal generation avoiding those systems that have less efficient generation and could present less losses in percentage.

(b) Some electric systems generate all the energy they require to supply their own demand while others purchase additional energy for its supply. These purchases shall in consequence be added to the net generation in order to have a statistics of an available energy input to the system.

(c) The sales of energy to other utilities correspond to commercial agreements that in general do not reflect the needs to the own demand of a particular system. In consequence it is convenient to substract them from the available energy in order to calculate the demand energy of the system. The demand energy varies slowly and in general increases constantly while the energy sold may present substantial changes from one period to another.

(d) The period considered for the energy balance may be variable. In general the most important is a year. In some systems, in order to analyze the seasonal variations, it is important to have balances at shorter periods, for instance a month. In these cases rather than considering a month as period it is important to consider a moving year period ending at the month of interest avoiding in consequence the problem that are found in process like billing that cover longer periods of time.

4.2 Percentage of Losses

One figure that is commonly used in energy statistics is the percentage of losses. It has been found that in order to find this number different basis is considered by different utilities including:

- Case A: The available energy that is the net energy input to the network including energy purchases.
- Case B: The demand energy but considering as part of the demand the auxiliaries consumption in generation.
- Case C: The demand energy without the auxiliaries consumption in generation.

From the generation point of view the losses in percentage shall be calculated according to case A that is considering the total energy input to the systems. However, this figure may reflect variations due to the sells to other companies. Therefore it is important to also compute the percentage of losses from the demand point of view, that is, according to case C.

5.0 Other Important Aspects Related to Non-Technical Losses

This document presents as appendix the paper "Assessment of electric energy losses in the Colombia Power network" which presents the work performed in order to determine the losses-causes and amounts-in Colombia and the best approach to correct them.

This study reflected that of a total of 19% of losses 2/3 were technical losses while 1/3 corresond to non technical ones. The non technical of 6.43% are distributed as follows:

- Non calibrated meters	1.03%
- User modified meters	0.93%
- Damaged meters	0.63%
- Estimated consumption	0.92%
- Theft and others	2.92%
Total	6.43%

As noted one important source of non-technical losses for this case is found associated to the energy meters. In fact the calibration of meters and the replacement of damaged meters would reduce the losses in approximately 2%. In addition the installation of meters in order to avoid the estimation of consumptions would reduce the losses to approximately 1%.

Theft in general, including the modification of meters is responsible for approximately 3.5% of losses. This amount can be reduced only if several aspects are considered including:

- The necessary legal backup to the utilities in order to permit the punishment of theft.
- The periodic visits to users with energy meters in order to detect the cases that imply that the meter is modified.
- The periodic visits to users with energy meters in order to detect the cases that imply that the meter is modified.
- The measurement of blocks of energy in areas of generalized theft in order to determine amounts of the energy not paid and determine the best way to legalize these areas.
- The supply of energy at tariffs that consider the reliability and quality of the service.

6.0 Conclusions

This document gives an overview of some important aspects of the "Losses problem" including the classification of losses and the statistics associated to them. These are considered important since they permit to define the causes and amounts of losses which are crucial questions to be answered before starting efforts in order to reduce the losses detected in any system.

Finally it is considered of utmost importance that general definitions are adopted in the Latin American region in order to start jointly an effort towards the solution of this problem which without doubt can be solved by us with our own resources.

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FIG. 1

ELECTRIC LOSSES

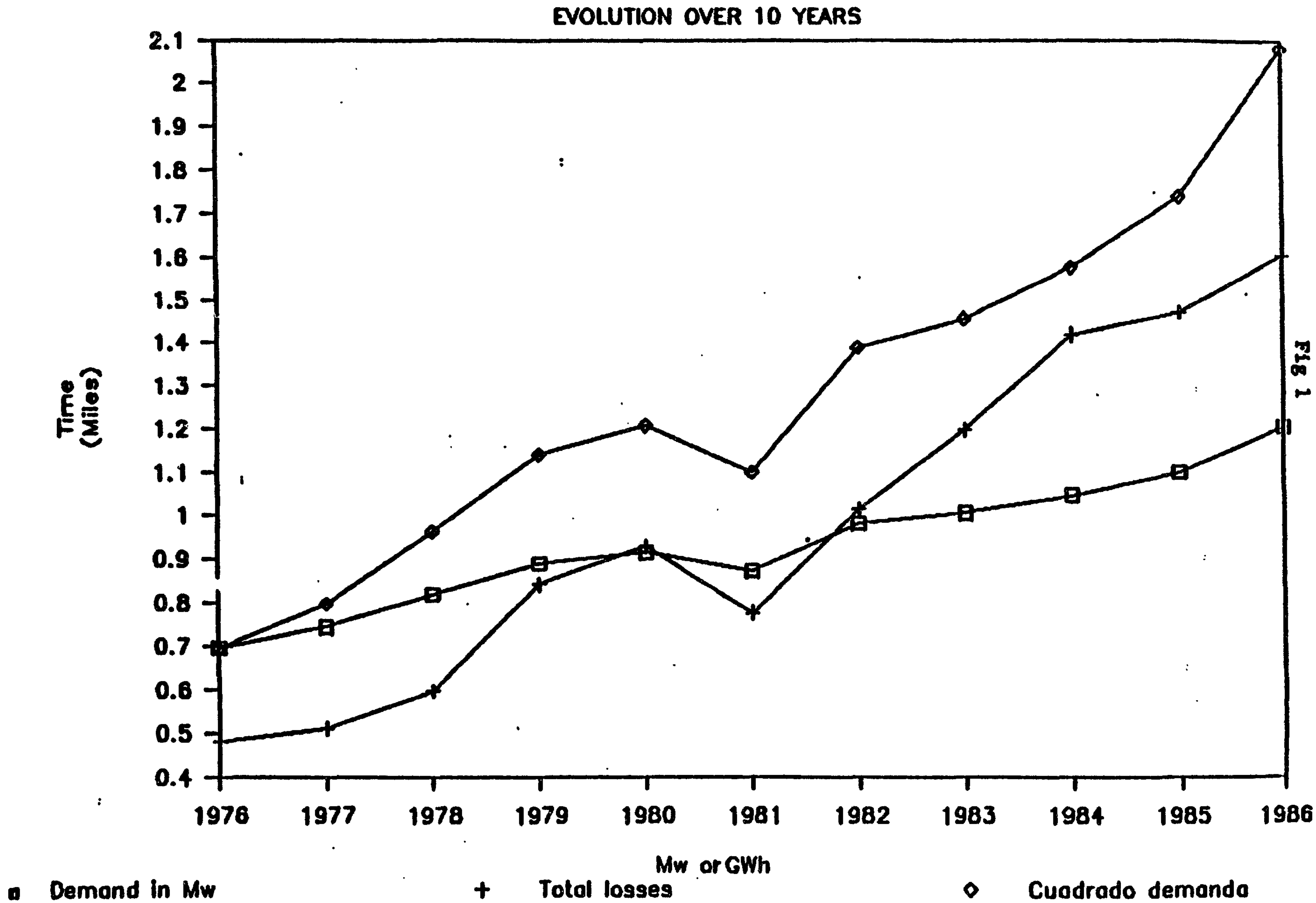

Fig 1

FIG. 2

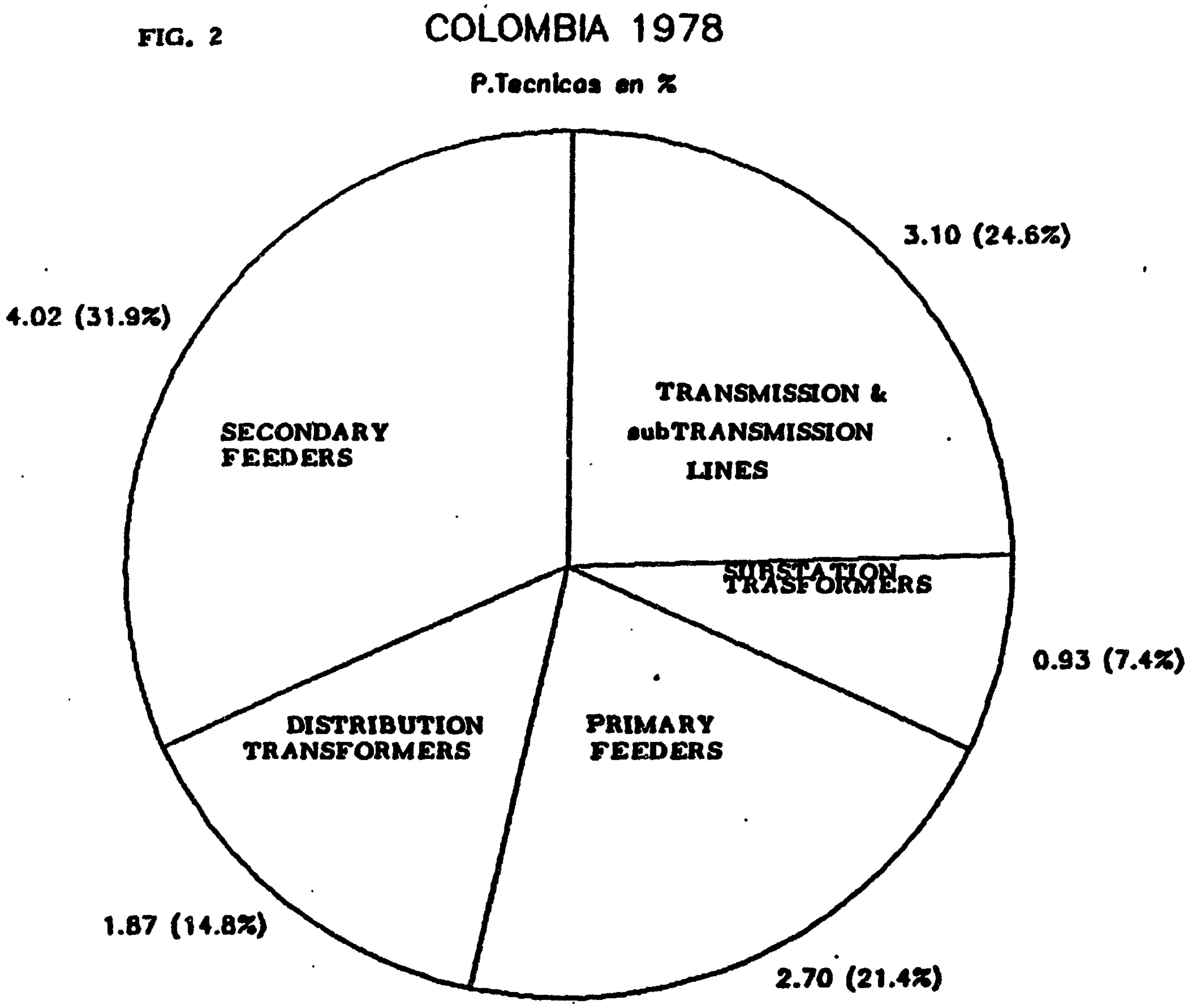
COLOMBIA 1978
P.Tecnicas en %
TRANSMISSION &
subTRANSMISSION
LINES
3.10 (24.6%)
SUBSTATION
TRASFORMERS
0.93 (7.4%)
PRIMARY
FEEDERS
2.70 (21.4%)
DISTRIBUTION
TRANSFORMERS
1.87 (14.8%)
SECONDARY
FEEDERS
4.02 (31.9%)

FIG. 3

CADAFE

P.Tecnicos en %

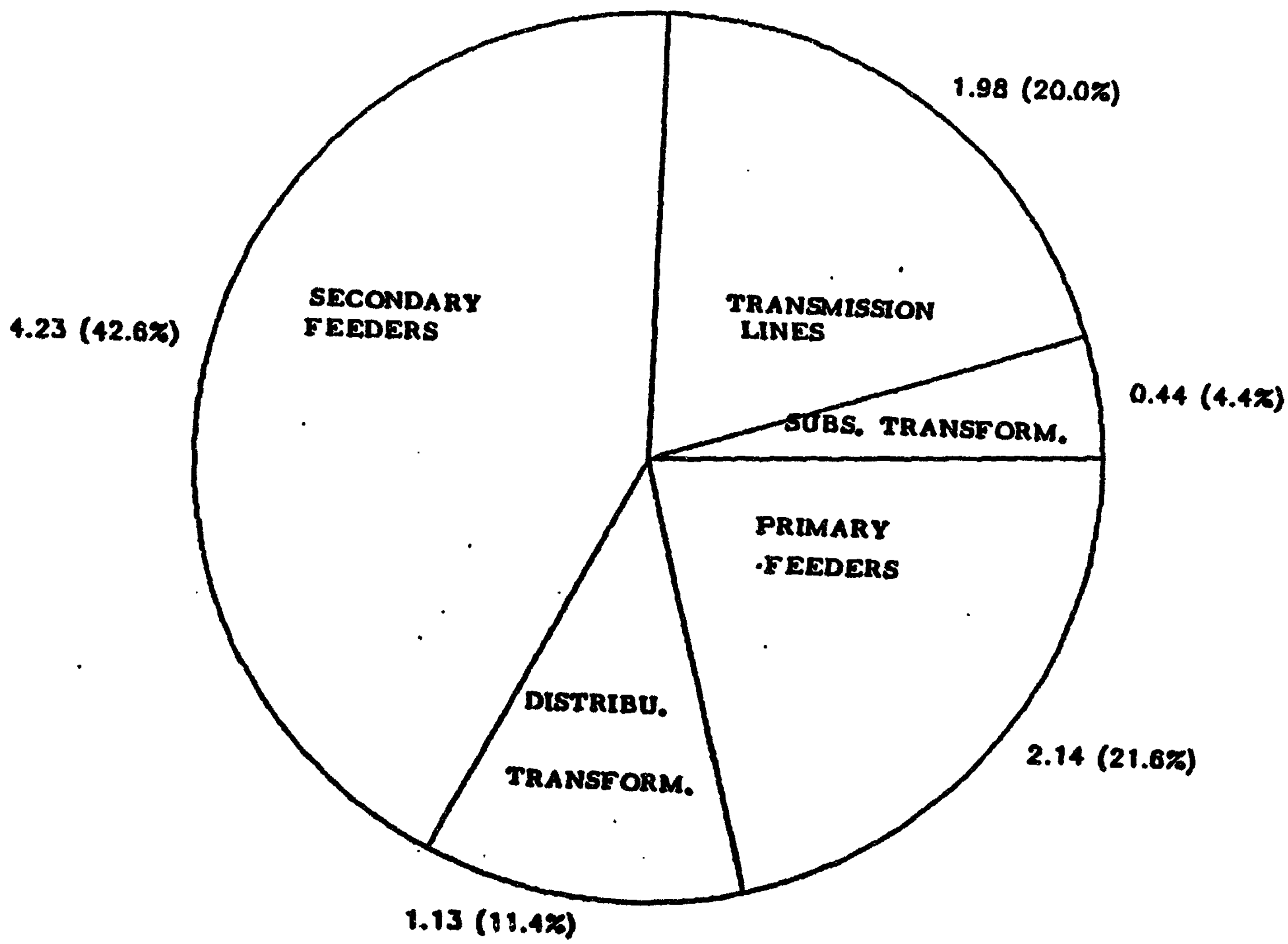

FIG. 4

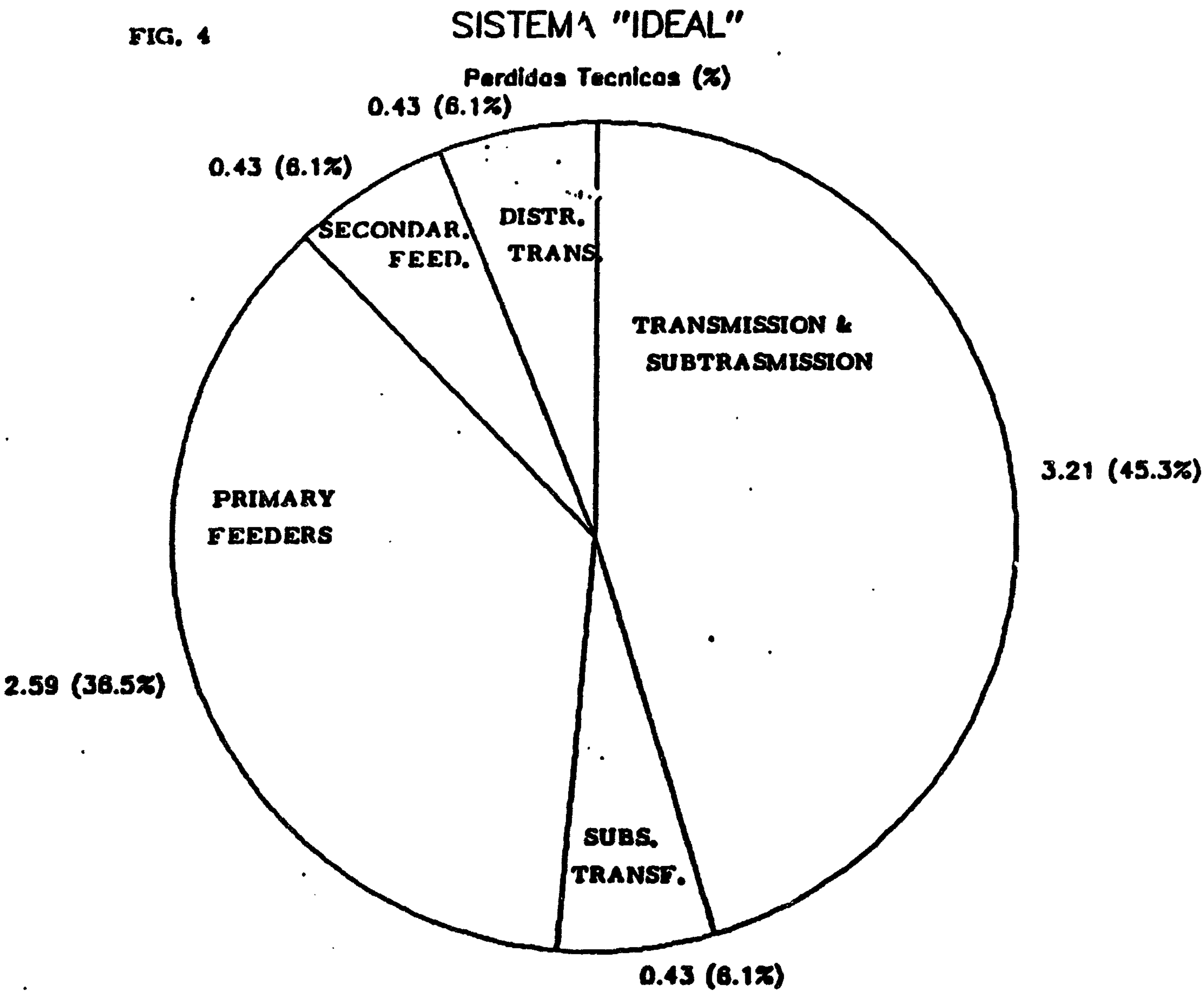
SISTEMA "IDEAL"
Perdidos Tecnicos (%)
0.43 (6.1%)
0.43 (6.1%)
SECONDAR. FEED.
DISTR. TRANS.
TRANSMISSION & SUBTRASMISSION
3.21 (45.3%)
PRIMARY FEEDERS
2.59 (36.5%)
SUBS. TRANSF.
0.43 (6.1%)

Fig 6

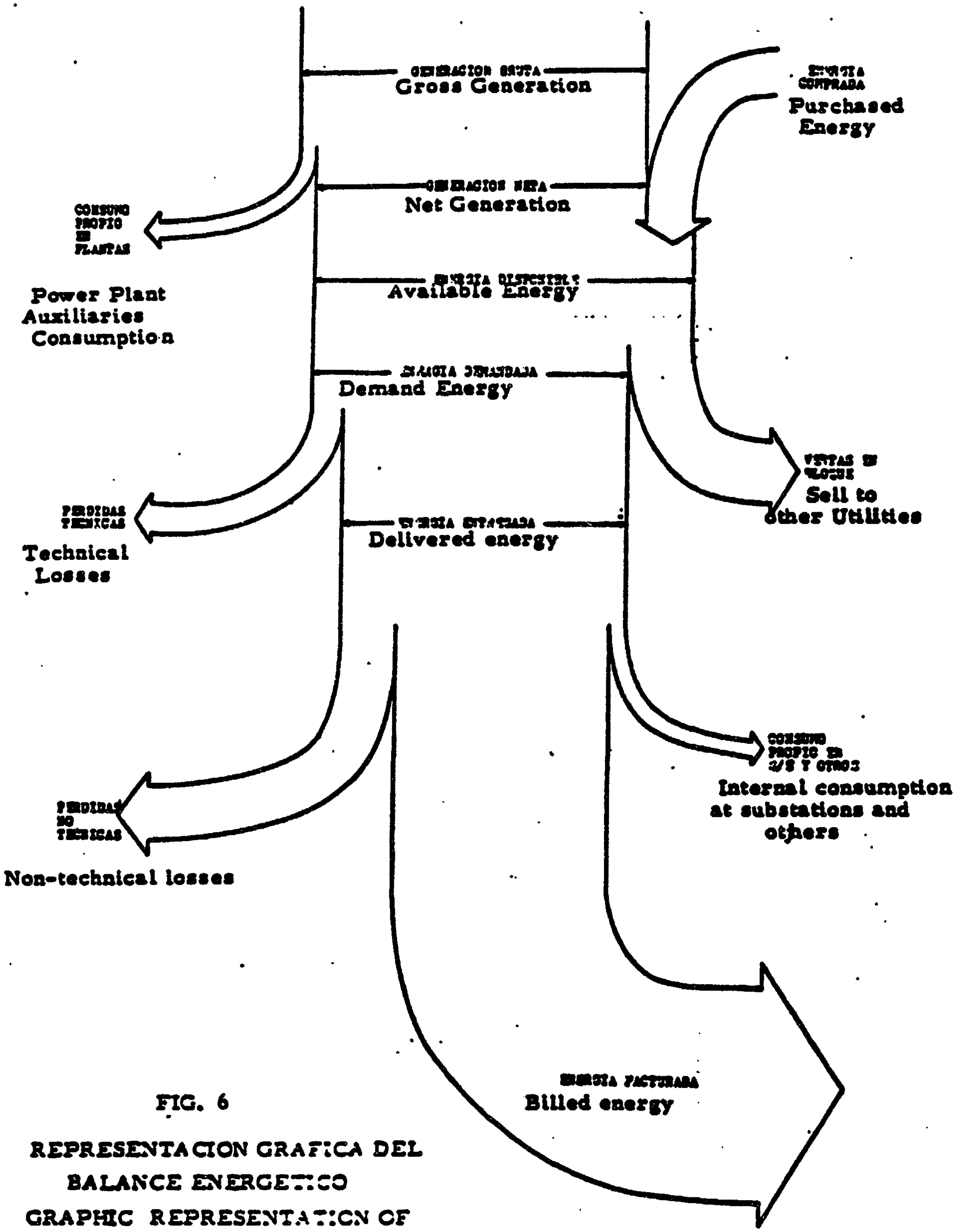

FIG. 6

REPRESENTACION GRAFICA DEL BALANCE ENERGETICO

GRAPHIC REPRESENTATION OF THE ENERGY BALANCE

Table 1: **COMPARATIVE TABLE OF ENERGY LOSSES**

TECNICAL LOSSES	COLOMBIA-1978(1)		CADAFE (2)			"IDEAL" (3)			"MAXIMO" (3)		
	% DEMAN.	% TECH	BASIC(*)	CORREC.	%TECN.	BASIC	CORREC	%TECN.	BASIC	CORREC	%TECN.
Transmission lines	1.98	15.7	1.80	1.98	20.0	1.40	1.50	21.2	2.80	3.20	22.6
Subtransmission lines	1.12	8.9				1.60	1.71	24.2	3.20	3.65	25.8
Substation transformers	0.93	7.4	0.40	0.44	4.4	0.40	0.43	6.0	0.80	0.91	6.5
Primary Feeders	2.70	21.4	1.4 -2.5	2.14	21.6	2.42	2.59	36.6	4.00	4.57	32.3
Distribution Transformers	1.87	14.8	0.7 -1.35	1.13	11.4	0.80	0.86	12.1	1.60	1.83	12.9
Secondary Feeders	4.02	31.9	3.1 -4.6	4.23	42.6						
LOSSES SUBTOTAL	12.62	100.0	7.4-10.6	9.92	100.0	6.62	7.09	100.0	12.40	14.16	100.0
NON-TECHNICAL LOSSES	6.43										
TOTAL	19.05										

(1) "Estudio de Perdidas Sistema Electrico Colombiano"
(2) L. Mazacan, Metodologias de Evaluacion y Reduccion de Perdidas
(3) M.Munasinghe, Energy Efficiency: Optimization of electric distribution...
For (3) peak losses converted to energy with 1.24 as factor
(*) Basic: data according to source normalized with generation
Corrected: data normalized with demand

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ASSESSMENT OF ELECTRICAL ENERGY LOSSES IN THE COLOMBIAN POWER SYSTEM

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Abstract - The electrical energy losses for the entire Colombian power network comprising distribution voltage levels up to the high voltage transmission levels are calculated. The energy losses are classified as "physical" losses corresponding to Joule effect (I^2R), Corona and core transformer losses and "black" losses which are defined as the difference between the energy available at the consumer level and the energy effectively billed by the different electric utilities in Colombia. A new methodology for calculating the "physical" losses is presented which is extensively based in the use of computerized methods including state estimation for the high voltage network and radial load flow for the distribution levels. The "black" losses including metering errors, theft and billing errors are calculated with statistical methods also using computerized tools. The results obtained highlight the importance of the losses in terms of loss of revenue for the electrical energy utilities.

INTRODUCTION

The electrical energy losses in a power system are produced by different causes including: Joule effect, core losses in transformers, deficiencies in the metering system, theft, etc. These causes can be grouped into two subgroups: the first including those that create losses that are inherent to the efficiency of the system to produce energy and to transport this energy to the end consumer, i.e., up to the point where this energy is sold by the electrical utility to the customer; the second group comprising the causes that create the difference between the energy available at the consumer level and the energy actually billed by the electrical utility. The first group of causes results in the "physical" losses of the power system; the second group is responsible for the "black" losses as named in this paper.

Interconexión Eléctrica S.A., ISA, the company that coordinates the national interconnected power system of Colombia decided to undertake a complete study in order to assess the amount of energy losses in the entire Colombian power system. The two major goals of ISA for this study were:

- The classification of the losses according to their importance in terms of economical impact and the feasibility of corrective actions that would reduce the losses.
- The definition of policies that would control and reduce the losses in the future.

In order to reach these goals the following specific objectives were defined for the study:

- Evaluate the information available at the different utilities, member of the Colombian Interconnected power network in order to determine its applications in the study.
- Estimate the energy losses by utility, by voltage level and by cause of loss with a methodology defined according to the available information.
- Evaluate the economic impact of the energy losses.
- Determine and analyze in terms of economy for the utilities, possible corrective actions that would control and reduce the losses.

The scope of the study covered the entire Colombian power system and the methodology used was designed in order to meet the study objectives subject to the time schedule and the human resources allocated to the study. This compromise resulted in a methodology that incorporated computer based tools which simplified the losses estimation process and met the required accuracy level.

This paper presents the methodology used in the losses study of ISA for the Colombian power system. The methods employed to determine all the identified types of losses are discussed at the light of the obtained results. More emphasis is given to this aspect as to numerical results which are particular to the power system studied.

CLASSIFICATION OF LOSSES

The energy losses in a power system were classified according to the following criteria:

a. By utility of the Colombian power network.

b. By voltage level where the losses occur.

c. By type of cause producing the losses.

Fourteen utilities of the Colombian power system were considered in the study; these utilities can be classified as:

- Two companies with only high voltage transmission lines and generation power plants.
- Five companies comprising generation, transmission and distribution of electrical energy.
- Seven utilities with power networks at the subtransmission and at the distribution levels.

The energy losses were evaluated for each utility considering all voltage levels comprised in each one. In addition, the losses for the integrated Colombian power network were obtained by totalizing the partial results.

By voltage level the energy losses were classified as:

Paper was published in the [illegible] of the 1983 Power Industry [illegible] [illegible] Conference PICA - 1983.

[illegible] 1983 [illegible]

- Losses in the transmission system.
  - i) Transmission line losses (220 and 115 KV).
  - ii) Transformer losses.
  - iii) Subtransmission line losses (66, 57.5 and 34.5 KV).
- Losses in the distribution system.
  - i) Primary feeder losses (13.8, 13.2, 11.4 and 4.16 KV).
  - ii) Distribution transformer losses.
  - iii) Secondary feeder losses (all low voltages - included).

By type of cause the losses were classified as:

- "Physical" losses which correspond to:
  - i) Corona effect losses at high voltages.
  - ii) Joule effect losses in lines and feeders - and in transformers.
  - iii) Transformer core losses.
- "Black" losses due to the following reasons:
  - i) Decalibration of energy meters due to nor - mal wear or due to wrong calibration by the utility.
  - ii) Intentional decalibration performed by the customers.
  - iii) Bypass of the energy meters.
  - iv) Damaged meters (blocked rotor).
  - v) Errors of billing customers that permanently or temporarily are billed without energy meters.
  - vi) Theft of energy of persons not registered - as customers in the utilities.

It should be noted that the energy lost in the - generation plant and substation auxiliaries is not included in the classification of losses by voltage le - vel or by cause. The reason for not including these - energy losses in this study was because the electrical utilities consider that the amount of them are well - known and little or nothing can be done in order to reduce them. For this reason the energy considered as the input to the power system is the energy generated- (gross generation) minus the energy consumed in the - auxiliaries. The net energy input to the system is named "Available" energy and is in consequence considered as 100% for this study.

Figure 1 presents a diagram representing the e - nergy losses as classified for this study.

The "black" losses calculated in this study are identified in figure 1. All the types of losses presented in this figure were evaluated separately with- the exception of theft and bypass losses which were - considered as the "black" variable and were in consequence evaluated as the difference between the energy- available for billing, the total billed energy and the calculated "black" losses.

METHODOLOGY FOR LOSSES EVALUATION

General Considerations

The classification of losses reflects the need to have several methodologies in order to evaluate the identified losses by cause. In addition it was necessary to adapt the methodology according to the information available in the power system utilities and to - the characteristics of the power system of each utility.

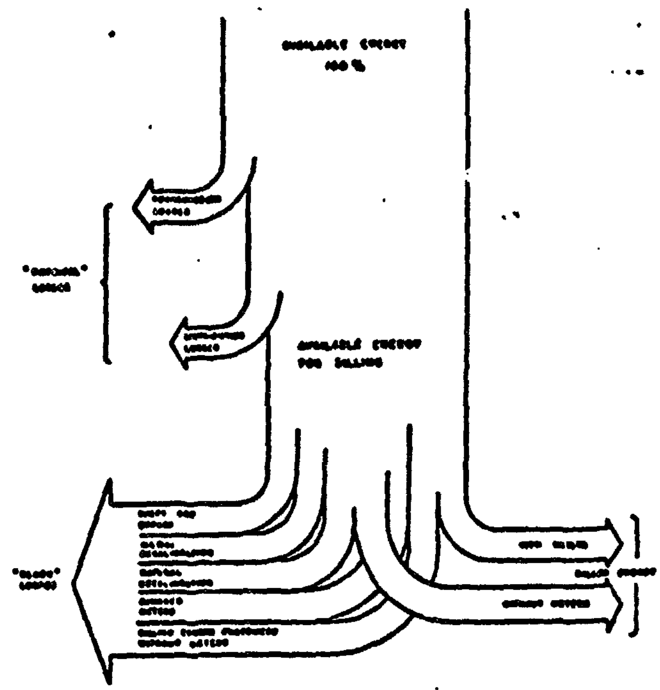

FIGURE 1. CLASSIFICATION OF ENERGY LOSSES

The examination of the information available for the study or collected during the study gave the following result:

- The information is more complete as the voltage- level increases, which allows for a good accuracy in the calculation of losses at the transmission and subtransmission levels.
- At the distribution levels the information is - rarely complete and particularly at the secondary voltage levels where the expected losses were greater, the information available at most of - the utilities in Colombia corresponds to global- figures (total length for example) or is inexistent.
- The information on theft and decalibration was - almost nonexistent at the time of starting the - study.

According to this result, the study was divided- in two consecutive phases:

- Phase One was dedicated to evaluate the "physi - cal" losses including all transmission and dis - tribution losses.
- During Phase Two the "black" losses were evaluated per cause as identified in the section des - cribing the classification of the losses.

Table 1 presents a summary of the methodologies-used for the evaluation of each type of losses according to the available information. These methodologies are explained in more detail in the next sections.

TABLE 1

SUMMARY OF METHODOLOGIES FOR LOSSES EVALUATION

TYPE	INFORMATION USED	METHODOLOGY
Transmission		
• I^2R Losses	• Redundant for all the system	• State Estimation
	• Complete for the studied system	• Load Flow
	• Incomplete	• Statistical Extrapolation
• Corona Losses	• Weather data transmission • line parameters	• Gamble and Konfanello method
Transformers	• Estimated parameters by transformer	• Complete transformer equivalent model
Primary Feeders	• Topology and measured or estimated loads.	• Radial load flow
	• Global data of the feeders: length of feeders, number of transformers, installed capacity, etc.	• Statistical models and regression
Distribution Transformers	• Estimated parameters by transformer and measured or estimated load.	• Complete transformer equivalent model
"Black" Losses		
• Uncalibrated meters	• Energy meters sample, utility test of meters and report.	• Statistical models, correlation and interpolation.
• Users billed without meter	• User information, historical billing records.	• Statistical correlation models
• Theft and bypass	• Available energy for billing, other calculated losses.	• By difference

Joule Effect Losses in the Transmission and Subtransmission System

The information available for the estimation of these losses consisted of:

- Energy meter readings.
- Readings of other power system data like voltages, active and reactive power in lines and transformers.
- Power system topology and parameters.

The direct use of the measurements for losses evaluation was considered not feasible because of the following reasons:

- No complete measurements are taken in all the required sites.
- The periodicity of the measurements changes from one company to another; this impacts the interconnection lines data.
- The measurements are not taken simultaneously.
- The accuracy of the readings is further impacted by human errors.

Figure 2 presents as an example, the active power measurements taken at both ends of a 220 KV line. This figure illustrates the impossibility to use directly and reliably the field measurements, to calculate the transmission losses, as the difference between both measurements would give power losses which do not correspond to reality.

In order to overcome the above difficulty, still using the available measurements and in order to minimize the measurement effort in the field, the use of State Estimation techniques was adopted.

The losses were estimated both in power (MW) and in energy (KWh). A state estimation program which uses the least square weighted method [1],[2] was developed. This program can accept all types of power system measurements including:

- Voltages (KV) at all bus-bars
- Active and reactive flows in lines, transformers and injections (loads and generation).
- Currents (Amps) in lines, transformers and injections (loads and generation).
- Angles of all bus-bars.

The developed program allows the use of all measurements logged manually by the substation and plant operators with a periodicity of half or one hour. From this data, it appeared that enough redundancy was available in order to take full advantage of state estimation. The major advantages of state estimation under the condition described were:

- It provides a reliable power flow solution which minimizes the influence of the normal errors imbedded in the measurements. Errors were estimated to be 2% for voltage measurements, 8 to 13% for active power and 27% for reactive power.
- It provides a useful manner to point out gross errors like configuration changes not reported in the log sheets by the operators. The program also identified "wrong" measurements like flows with wrong flow direction.

In order to asses the amount of losses a sample week was selected. This time period was considered the minimum to include different operating conditions. Of the 168 hours of the week, the 91 hours with the most variable load conditions were analyzed using the field measurements. The analysis was performed as follows:

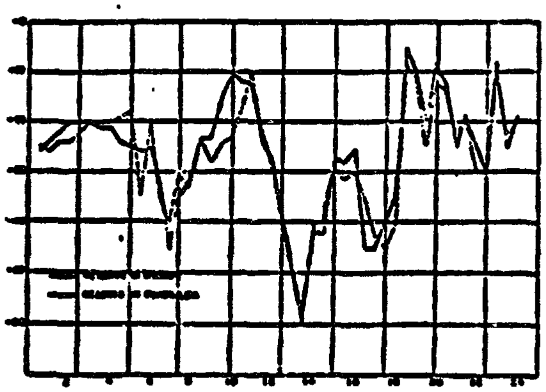

Fig.2 Active Power readings in the line ESMERALDA-GUATAPE in a 24 hour period.

- The power losses were determined for each hour with the state estimation program. An analysis subroutine of the program established directly the losses by company, by voltage level and calculated separately the losses of lines and transformers.
- The energy losses were determined by numerical integration of the power losses for the studied time period. The trapezoidal rule of integration was used.

The results obtained for the energy losses were as follows:

- Transmission lines: 2.0% of the available energy for the entire Colombian system; per utility, the minimum was 0.2% and the maximum 3.5%.
- Subtransmission lines: 1.1% for the entire Colombian system; per utility, the minimum was 0.1% and the maximum 1.6%.
- Transformers: 0.9% for the entire Colombian system; most of the utilities presented losses in the range of 0.5 to 0.6%.

Corona Effect Losses

The Corona losses were calculated for all the lines with voltages of 220 KV, the maximum voltage level in operation in Colombia. The method of Comber and Zafanella was selected after a comparison with the methods proposed by Sugimoto and Gari and Clade [3], as it gave intermediate results between the calculation for "new" and "old" conductors proposed by Gari and Clade while the Sugimoto method gave lower values than the other two methods. The Corona effect losses calculation took into account the configuration of the lines, the characteristics of the conductors and the meteorological conditions. The latter ones were gathered from weather control stations located close to the areas of the transmission lines; data of the same sample week as for the transmission line losses estimation was used. The energy losses in percentage were estimated to be 0.8% of the available energy.

Primary Distribution Feeders

All the feeders in Colombia operate as radial lines; thus, the analysis for evaluating the losses in this part of the system was consequently simpler than the one used for the transmission and subtransmission levels. The following simplifications were made:

- The power factor of all the loads was assumed to be equal to the power factor of the feeder as measured at the substation.
- The unbalance between phases was neglected and a one line equivalent was used for losses calculation.
- The amount of load in each distribution transformer was determined according to the available information: measured peak loads or load distribution according to transformer capacities.
- The voltage was considered constant for the feeders.

The previous simplifications do not introduce significant errors as determined for the power systems analyzed. In particular, not considering the voltage drop introduces an error of less than 2.5% which is negligible given the accuracy of the remaining data used.

For the feeders for which the topology was known and considering the simplifications described, a radial power flow program was developed based on reference [4]. A sample of more than 20% for most of the analyzed utilities was studied.

The data used by the program is the following:

- Data logged at the substations: busbar voltage, phase currents, active and reactive power for the feeders (where available), energy consumed by the feeder (where available).
- Feeder topology and transformer loads as measured in the field or calculated according to distribution factors which assign to each transformer a portion of the total feeder load based on the transformer capacity.

The power losses were calculated only for the peak load detected for each feeder during the sample week. The energy losses were calculated from the peak losses, the time period considered and the load and losses factors defined as:

$$F_L = \frac{1}{168}\sum_{k=1}^{168}\frac{I^2(k)}{I^2 peak} \qquad F_c = \frac{1}{168}\sum_{k=1}^{168}\frac{I(k)}{I\ peak}$$

where:

$I_{(k)}$ is the current measured for hour k of the sample week.

I peak is the peak current of the sample week.

F_L is the losses factor

F_c is the load factor

The energy losses can be calculated in percentage as:

$$\text{Energy Losses } (\%) = \text{Peak Losses } (\%) \times \frac{F_L}{F_c}$$

The result obtained for the primary distribution feeders were: 2.7% of the available energy with a maximum of 7.4% and a minimum of 0.9% depending on the utility analyzed.

Distribution Transformers

For distribution transformers losses evaluation the same simplifications as for the primary feeders were made. Joule effect losses and core transformer losses were calculated from equivalent transformer circuits which were determined for each transformer type. The losses in the distribution transformer were estimated to be 1.9% for the Colombian system with the values per utility in the range of 1.5% to 2.3%.

Secondary Distribution Feeders

The same methodology employed for the primary feeders was applied for the evaluation losses in the secondary distribution feeders. Field measurements and customer distribution factors were used instead of substation measurements and transformer distribution factors. The evaluation losses for the Colombian system in this area where estimated to be 4.0% with a range between 2.4% and 6.3% on a per utility basis.

"Black" Losses

These losses were evaluated considering all possible sources of energy losses as presented in figure 3.

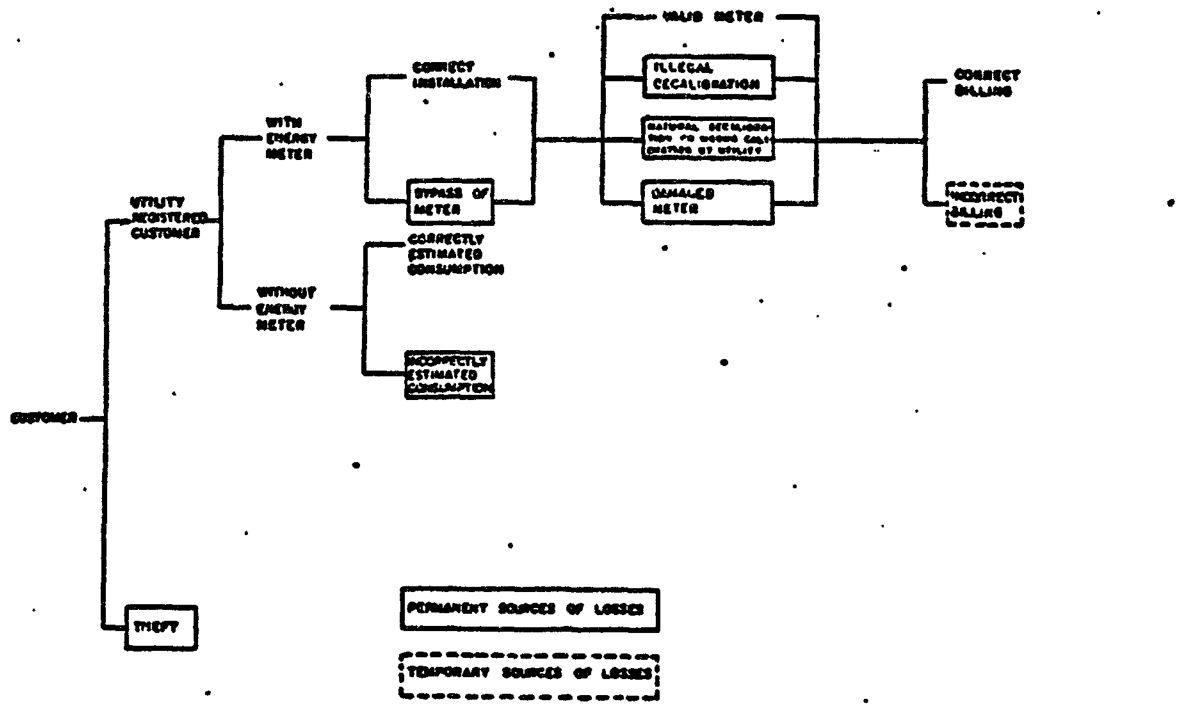

FIGURE 3 - DISTRIBUTION OF "BLACK" LOSSES

In this figure the causes that produce permanent and temporary losses are identified. Due to the statistical nature of the problem a sample of customers was selected. The size of the sample was determined to be in the order of 0.5% of the total number of customers of each company. As the range of customers for the utilities considered was between 50.000 and 500.000 users the sample size varied from 250 to 2500. A form containing questions related to the conditions of the electrical installation and the energy meters as detected during field and tests performed in the companies' test workshops was elaborated in order to detect the causes of loss and to evaluate the losses for the selected sample. The customers' installations were inspected, their energy and meters were removed and calibrated by the corresponding utility and reinstalled or changed if found to be damaged. The following sections present the methodology used to evaluate the losses and the results obtained.

__Decalibrated Meters__

The losses due to natural decalibration of meters or due to incorrect calibration performed by the utility are considered under this cause. Figure 4 presents a typical curve of decalibration as function of the percentage of nominal current. Three zones of low, normal and high current are identified in this figure. For very low currents the decalibration reaches 100% due to the meter energy consumption. Three models to approximate the meter curve were considered in the study; these were: a quadratic, a logarithmic and a linear model. The three models are illustrated in figure 5. In this figure the curves for a meter that is 100% calibrated at 100% and 200% of nominal current are shown. For the evaluation of losses three points were determined for testing each one of the sampled meters; the selected points were 10%, 100% and 200% of nominal current. The decalibration values for these points were determined and with this data the different models were compared. Due to the fact that most of the average consumption currents of the customers are in the range of normal current (between 10 and 30%) and that in this area the linear model provided accurate results, this model was selected for the losses evaluation.

The energy losses estimated in this study for decalibrated meters were 1.1 of the available energy for the Colombian system but the analysis per utility provided results ranging from -0.1% (decalibration favorable to utility) to 3.4%.

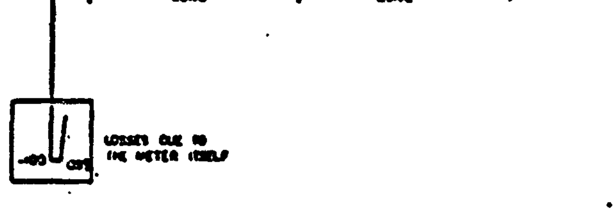

FIGURE 4 - TYPICAL ENERGY METER CHARACTERISTIC CURVE

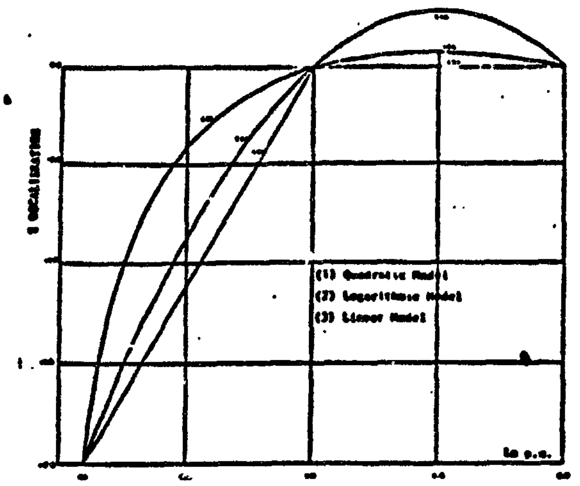

FIGURE 5: MODELS FOR ENERGY METERS CHARACTERISTIC CURVE

Illegal Decalibration

The energy meters illegally decalibrated were determined by two methods: by inspection and by statistical analysis. By inspection the meters that presented deficiencies in metering one or two phases were noted as such. Besides, other meters which presented statistically unexpected high decalibration were classified as to produce losses due to illegal decalibration. The break point between natural and illegal decalibration was established to be in the range comprised between -10% and -23% of decalibration depending on the utility studied. The losses evaluation for illegal decalibrated meters was done in the same manner as for naturally decalibrated meters. The results obtained are 0.9% of the available energy for the Colombian system. The range on a per utility basis was determined to be between 0.1 and 2.1%.

Damaged Meter

A damaged meter was considered as one that does not measure any energy because of blocked rotor for example. The approach to determine the losses for the electrical utility was to consider that in average the meter is damaged in the middle of the period comprised between two consecutive readings of the meter. As normally a blocked meter is only detected by two identical readings it was established that the losses for the company correspond to the energy consumed in a time period comprised between one and a half periods of meter readings. Based on this consideration the amount of losses were estimated to be 0.6% of the available energy for the Colombian system with a maximum of 6.8% and a minimum of 0.2% on a per utility basis.

Incorrectly Estimated Consumption

During this study it was determined that some of the utility registered customers are billed for a fixed amount of energy due to their low consumption (users permanently with this billing approach) or due to special conditions like temporary service, change of energy meter, etc. For these customers a statistical method was designed considering the geographical area, the installed load of the customer and the consumption of customers with similar characteristics but which were billed with energy meters. The energy consumption of a "typical" customer per area comprising around 500 customers was calculated. The customers in the same area billed without meter were considered to have the same consumption as the "typical" customer. The losses were estimated as the difference between the estimated consumption and the billed energy. The losses evaluated due to this cause were 0.9% of the available energy for the Colombian system with a minimum of 0% and a maximum of 1.6% on a per company basis. The computer was extensively used for this calculation as the number of analyzed customers was over 50.000.

Theft and Bypass

These losses were evaluated as the difference between the available energy for billing (see figure 1), the billed energy and the evaluated "black" losses. The losses estimated were 2.9% for the Colombian system with a maximum of 13.5% and a minimum of 1.8% according to the results per utility.

Additional Methods Employed

For primary and secondary distribution feeders where only global data was available statistical correlation methods were used. Different models were tested through correlation with feeders which losses were evaluated by radial load flow. From this analysis the parameters of the selected models were determined and used for the systems where the global data was available.

CONCLUSIONS

The energy losses in a utility are more and more important as the costs of producing energy and as the price of installing new generating capacity are increasing. Due to this fact, it is of major importance for the electrical utilities to asses the amount of losses and to know, with enough accuracy, where and in what amount the losses are produced in order to take corrective actions that can reduce the significant associated loss of revenue. This study presents a complete methodology for the assessment of losses according to the described classification. The state estimation techniques with manually logged data appears to be the most appropriate method in order to obtain good results with fairly accurate information and with a minimum of measurement effort in the field. The methods employed for distribution losses evaluation based on a radial load flow gave accurate results but as the amount of data to be processed at this voltage level is very high, it is imperative to work on a sample of feeders and extrapolate the results to the rest of the power system.

The major contribution of this paper is the attempt to classify and to evaluate the "black" losses as presented. From the results obtained for the Colombian system it is concluded that 2/3 of the losses are due to "physical" losses and 1/3 to "black" losses. The analysis of possible corrective actions also performed as part of the study, revealed that the evaluated losses could be diminished considerably with moderate economic investments and high potential benefits for the utilities. The results are in accordance with recently published papers [5], [6], [7], [8] and therefore highlight the importance of this type of study for other utilities.

ACKNOWLEDGEMENTS

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R. Yari
plus de 1 000 000 h.
de 100 000 à 1 000 000 h.
de 50 000 à 100 000 h.
aéroport

A STATISTICAL APPROACH FOR EVALUATING SOME NON-TECHNICAL LOSSES IN POWER SYSTEMS

By

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ABSTRACT

A statistical method to measure those non-technical losses which are caused by alteratio.s in watthour meters is presented. The methodology is suitable to determine: (i) the number of fraudulent customers as well as the number of non-fraudulent customers per consumer category; (ii) the amount of non-billed energy as a consequence of alterations on meters, per consumer category; and (iii) a fair billing system, so as to recover losses due to detected infringements. This methodology is based on sampling techniques and statistical theory, has been originally developed by Dr. Jose Luis Calabrese and tested at the Empresa de Energia Electrica de Bogota in Colombia 1/, with promising potential for further use in other power utilities in Latin America and the Caribbean. The paper is oriented to power engineers and therefore does not concentrate in mathematical demonstrations or pure statistical analyses.

1. INTRODUCTION

It is well known that methodologies to measure, evaluate, reduce, and control losses in power systems, mainly concentrate on technical losses. In practice however and taking into account the Latin American and Caribbean context, it is very common to find power utilities in which non-technical losses are higher than those of technical origin. The present paper is an attempt to establish a suitable method for measure those non-technical losses arising from alterations in watthour meters, and where an exhaustive inspection of meters is not feasible due to costs and time constraints. In those cases, one is normally guided by rough estimates of loss figures and the usual approach is in accordance with rules of thumb.

One practice that is quite common in most utilities in the region is that of deriving non-technical loss figures as a subtraction of calculated technical losses from total measured losses. Although that methodology is correct in principle, it may hide several procedural errors, the most obvious of them being that of using different time periods among the measured produced energy and the corresponding billed energy, to derive total losses. Another

1/ METHODOLOGIES DE EVALUACION DE PERDIDAS NO TECNICAS. Jose Luis Calabrese, OLADE 1988.

source of uncertainty refers to the methods used to calculate technical losses. They may range from state estimation techniques to simple Ohm's law application in distribution feeders, including the well known load flow algorithms. Although those techniques may be quite sophisticated from the computational standpoint, the data to be used is normally error prone and engineering judgement is commonly used to assume "representative" active and reactive power demands in the nodes of the corresponding networks.

The calculation of non-technical losses as the difference of two not very reliable figures, gives therefore a doubtful result. It is well known that in economic and engineering disciplines, sometimes rough estimates are sufficient to make decisions. In the reduction of losses in power systems, however, a good knowledge of the absolute loss figures and a disaggregate of them may help management and decision makers in their efforts to reduce losses in the most cost effective way. This fact, highlights the urgent need to improve measurement technique for technical and non technical losses.

One approach that may result promising is that of using representative sampling techniques and statistical inference to the universe. The use of this approach is gaining impetus worldwide, as a result of recent improvements in computer technology and their corresponding costs reductions.

In Latin America and the Caribbean a significant portion of non-technical losses has been attributed to altered watthour meters at all consumer category levels. These losses not only adversely affect the financial performance of the utilities, but also distort the composition of future demand. In fact, in utilities where prices (tariffs) do reflect costs, those non fraudulent consumers may be paying more than they should, affecting in consequence their future levels of consumption, given that in the long run, price elasticities are not zero.

2. BASIC DEFINITIONS

Before embarking on a description of the proposed methodology, it may be worthwhile to discuss some basic definitions and assumptions which will be used throughout the paper.

2.1 Billing Factor

A billing factor may be defined as:

$$BF = Eb/(T * Pi) \qquad (1)$$

where "Eb" represents the billed energy during the period "T", to a consumer whose installed active power is "Pi". The billing factor may be interpreted as the relation of the actual billed energy to the theoretical maximum possible billed energy for a given consumer in a given period of time "T".

Using the above definition, and considering two customers with similar electricity consumption behavior, that is, with the same installed power "Pi" and consuming the same amount of energy "Ec" during period "T", but assuming that one has a fraudulent watthour meter, their corresponding billing factors may be calculated as:

$$BFf = Ebf/(T * Pi) \qquad (2)$$

$$BFn = Ebn/(T * Pi) \qquad (3)$$

where "f" represents for the fraudulent customer and "n" the non-fraudulent one. Since it is assumed that both customers consume the same quantity of energy "Ec" during period "T", it may be inferred that:

$$Ebn > Ebf \qquad (4)$$

and therefore:

$$BFn > BFf \qquad (5)$$

Expression (5) means that given two customers with the same electricity consumption behavior, the billing factor of the non fraudulent one is always greater than that corresponding to the fraudulent customer. This conclusion should be borne in mind as it will be utilized in statistical terms, for customers of the same consumer category, with the same electricity consumption behavior.

2.2 Relationship Between "BF" and Pi"

It is worth noting, at this point, the differences between the billing factor, defined in (1), and the commonly used load factor of expression (6).

$$LF = Ec / (T * Pm) \qquad (6)$$

In expression (6), "Ec" represents the energy consumed during period "T", by a customer (load) with a maximum demand of "Pm". The billed energy "Eb" used in definitions (1), may be equal or less than "Ec", depending on whether the customer is non fraudulent or fraudulent, respectively. Installed power "Pi" is normally greater than maximum demand "Pm" and in some cases may be equal.

The commonly used load factor may be interpreted as the portion of energy that is actually consumed in relation to the energy that may be consumed with a constant maximum demand lasting for the whole period "T". The billing factor, may be interpreted as the portion of energy that is actually billed in relation to the energy that could have been billed if the customer would have used its installed power during period "T".

Normally, the load factor is used as an inherent indicator of the load in the sense that it measures how the maximum demand is utilized. Similarly, the billing factor may be used as an inherent indicator of the customer, because it measures how the installed power is used.

From expressions (2) and (3) it may also be concluded that there is no correlation between the billing factor "BF" and the installed power "Pi". In fact, two customers with the same installed power "Pi", consuming the same amount of energy "Ec" during period "T" may have different billing factors "BDf" and "BFn", depending on the alteration or not in their watthour meters respectively.

The last remarks, in statistical terms mean that the covarience between the billing factor and the installed capacity is nil. Mathematically:

$$\mathrm{Cov}\,(BF, Pi) = 0 \qquad (7)$$

Expression (7) will be used in making statistical inferences on the basis of a sample and extended to the universe in a given consumer class.

2.3 Correcting Detected Fraudulent Energy Bills

Considering the hypothetical case of the two consumers with the same electrical behavior, and considering that one of them is fraudulent and the other is not, expression (5) has been derived. From expressions (2), (3) and (4), one obtains:

$$Ebn = BFn * T * Pi \qquad (8)$$

$$Ebg = BFf * T * Pi < Ebn \qquad (9)$$

Having assumed that both customers consume the same quantity of electricity "Ec", and considering that the non-fraudulent customer has been correctly billed, the non-billed energy for the fraudulent customer may be calculated as:

$$NBE = Ebn - Ebf = (BFn - DFn - BFf) * T * Pi \qquad (10)$$

or:

$$NBE = d * T * Pi \qquad (11)$$

where d = BFn - BFf is the difference between billing factors for the non fraudulent and fraudulent consumers respectively. Conceptually, it is therefore possible to calculate the unbilled energy of a fraudulent consumer, knowing its installed power "Pi", its billing factor "BFf" and the billing factor of an equivalent customer. This principle shall be expanded in statistical terms to the universe.

3. METHODOLOGICAL FORMULATION

3.1 Methodological Approach

The first step for the formulation of the present approach for determining non technical losses due to altered watthour meters, is the division of customers in consumer classes. Disaggregated information of customers must be pursued as much as possible. An initial approach may be that of utilizing consumer categories which are established by the utilities. It is highly advisable to disaggregate customers within each consumer category, so as to classify them in consumer classes.

Having classified the customers into consumer classes, a sampling process must be carried out within each class. The sample components must be chosen at random, and its size can be initially determined using well known statistical formula to do so. One commonly used formula 2/ is that of expression (12):

$$n = \frac{pq\ N}{(a/2)\hat{}2\ (N-1) + pq} \qquad (12)$$

where

n = sample size
p = probability of occurrence of the phenomenon in question
q = 1-p
N = population size (size of the consumer class)
a = sampling error given by the losses evaluator (for instance 0.05 for a confidence interval of 95%)

In the present formulation, since the sampling process may have two possible outcomes, that is altered or unaltered meters probabilities p and q are both 0.5. Error "a" may be interpreted as the probability of those cases for which the sample does not represent the population (consumer class). For instance an error a = 0.05 would mean that in 5% of cases, the calculated sample does not represent the universe (population class).

Table 1 lists different sample sizes for different confidence intervals, for three different sizes of consumer classes.

2/ Household Energy Consumption in Rio de Janeiro Shanty Towns. Alfredo Behrens, International Development Research Center, June 1988.

Table 1: SAMPLE SIZES FOR DIFFERENT CONFIDENCE INTERVALS WITH THREE DIFFERENT SIZES OF CONSUMER CLASSES

P = 0.5 AND Q = 0.5

a	Confidence Interval	Size of the Universe (N) for each Consumer Class		
		n	n	n
0.01	99%	5.000	909	99
0.02	98%	2,000	714	96
0.03	97%	1,000	527	92
0.04	96%	588	385	86
0.05	95%	385	286	80
0.06	94%	270	218	74
0.07	93%	200	170	67
0.08	92%	154	135	61
0.09	91%	122	110	55
0.10	90%	99	91	50

It is noteworthy that the greater the consumer class, the smaller the relative size of the sample for a given confidence interval. Thus for instance, for a given confidence interval of 97% the sample would be of 1,000 customers for a universe of 10,000 (10% of the class), 527 customers for a universe of 1,000 (more than 50% of the class), and 92 customers for a universe of 100 (more than 90% of the class). It is also important to bear in mind that the greater the required confidence interval, the greater the size of the sample.

Once the sample size has been defined and customers belonging to that sample are selected at random, a site survey should be conducted in order to analyze their electrical installations. First a careful inspection of watthour meters should be carried out. From it the number of fraudulent and non-fraudulent customers may be determined, and their proportion may be extended to the consumer class.

The survey must be concluded by an installed active power calculation for each surveyed customer. For that purpose, nameplates of electrical machines and appliances may be utilized if possible. If that information is lacking, measurements may be done machine by machine, using preferably wattmeters or else clamp ampmeters and voltmeters and estimated power factors. The later may however introduce errors, and should thus be avoided. Having the results of the site survey, and records of electricity consumption, by customers billing factors may be calculated for fraudulent and non fraudulent consumers.

The sample may be subdivided into two sub-classes, namely fraudulent and non-fraudulent. The mathematical expectation of real energy consumption, for the non-fraudulent sub-class, may be calculated as:

$$E[RCn] = T * E[BFn] * E[Pin] \qquad (13)$$

and for the fraudulent sub-class it can be assured that:

$$E[RCf] > T * E[BFf] * E[Pif] \qquad (14)$$

It is important to note at this point, that expressions (13) and (14) are implicitly assuming that there is no correlation between the billing factors and the installed power. This fact has been discussed previously when analyzing two consumers with the same electricity consumption behavior with its corresponding mathematical conclusion as represented in expression (7). Should there exist correlation between the statistical variables "BF" and "Pi" expression (13) and (14) should take into account a further term with the covariance between those variables. Observing expressions (13) and (14) it can be said that they are statistical extensions of expressions (8) and (9). The expected real consumption for the fraudulent consumers, may be calculated using the mathematical expectation of the billing factor corresponding to the non-fraudulent consumers, as:

$$E[RCf] = T * E[BFn] * E[Pif] \qquad (15)$$

Expression (15) is a statistical extension of the concept inherent in expression (10). In fact, in expression (10) the real consumption of a fraudulent consumer has been calculated using the billing factor of a non-fraudulent consumer, with the same electricity consumption behavior. In expression (15), the same procedure has been adopted, but this time in statistical terms.

Subtracting expression (14) from expression (15), the mathematical expectation of the unbilled energy due to watthour meter alterations, within the sample, may be calculated as:

$$E[NBE] = T * E[Pif] * (E[BFn] - E[BFf]) \qquad (16)$$

On replacing mathematical expectations with calculated mean values, the mean unbilled energy may be calculated as:

$$M[NBE] = T * M[Pif] * (M[BFn] - M[BFf]) \qquad (17)$$

The amount of electricity not billed within the consumer class under consideration, thus may be calculated as:

$$TNBE = N * Nf * T * M[Pif] * (M[BFn] - M[BFf]) \qquad (18)$$

where:

N = Number of customers in the consumer class under consideration (universe).

Nf = Proportion of fraudulent customers, within the consumer class under consideration. It is equal to the proportion of fraudulent consumers within the sample. That is FN = nf/n, being "nf" the number of fraudulent consumers in the sample of "n" consumers.

Results of expression (18) may be used to guide management and decision makers on evaluating the convenience or inconvenience in pursuing further searches of altered meters in each of the defined consumer classes. In fact, by valuating TNBE in economic terms and considering the costs of an exhaustive search for each consumer class, a cost benefit analyses can be conducted, so as to determine a merit order of future actions in accordance with descending benefit/cost ratios. In fact, those consumer classes with high benefit/cost ratio should be surveyed with high priority, leaving those with smaller values as lower priorities, within the actions to reduce non-technical losses.

Summarizing what has been proposed so far, the steps to pursue are as follows:

(1) Definition of consumer classes, to the highest disaggregation level possible.

(2) Definition of sample sizes per consumer class.

(3) Conduct of site surveys to detect fraudulent consumers and to calculate the installed active power per consumer.

(4) Calculation of consumers with fraudulent and non-fraudulent watthour meters, per consumer class extending the proportions of the sample to the universe.

(5) Calculation of billing factors for fraudulent and non-fraudulent consumers.

(6) Calculation of mean values for billing factors and installed power.

(7) Calculation of the total non billed energy (TNBE), resulting from alterations in watthour meters.

(8) Cost benefit analyses to prioritize actions for the reduction and control of fraudulent, non-technical losses.

3.2 Fair Billing of Fraudulent Consumption

In order to formulate a methodology suitable for the fair billing of fraudulent consumption it is convenient to mathematically adjust the statistical distribution of billing factors. In the study conducted by Dr. Jose Luis Calabrese at Empresa de Energia Electrica de Bogota, he found "Gamma functions" were most appropriately adjustable to the statistical distributions of billing factors, Gamma functions have the following mathematical expression:

$$f(BF) = \frac{A\hat{}r}{J(r)} (BF)\hat{}(r-1) * e\hat{}(-A*BF) \qquad (19)$$

where

A > 0 is a constant that may be calculated knowing the mean value "M[BF]" and the variance V[BF] of the billing factor distribution.

r > 0 is a constant that can also be calculated knowing the mean value and the variance of the distribution.

e Base of the Neperian logarithms.

J(r) A function of constant "r", which may be calculated as:

$$J(r) = \int t\hat{}(r-1)\, dt \qquad (20)$$

Constants "A" and "r" may be calculated solving the following system of equations:

$$\begin{aligned} M[BF] &= r/A \\ V[BF] &= r/A\hat{}2 \end{aligned} \qquad (21)$$

The solution of the above system of equations is:

$$A = M[BF] / V[BF]$$
$$r = (M[BF]^2) / V[BF] \qquad (22)$$

Figure 1 shows a typical shape of a Gamma distribution function partially skewed to the left. It is important to note at this point, that depending on the relative values of constants "A" and "r", the Gamma function can change its skewness from the left to the right, or even to become a normal distribution. In practice however, it would be suspected that skewness would be placed to the left in those consumer classes with high installed power but with low consumption.

The procedure for finding a system of fair billing to infringing customers, consists in adjusting the statistical distribution functions for the billing factors of fraudulent and non-fraudulent sub-classes, as illustrated in Figure 2. There it can be seen that the fraudulent customers billing factor, distribution function is shifted to the left with respect to those of non fraudulent customers. This fact is in accordance with expression (5), in which it has been demonstrated that the billing factor for a non fraudulent customer is always greater than that corresponding to a fraudulent one, with similar electricity consumption behavior.

Having the billing factors distribution function, and assuming that a fraudulent customer has been detected by a site survey, and using his records of electricity consumption and his calculated installed active power, his particular billing factor BF1 can be calculated. Using BF1, from the distribution function of fraudulent consumers a distribution value of f1 may be calculated, as illustrated in figure 2. f1 represents the portion of fraudulent consumers from the consumer class under consideration that statistically have the same electricity consumption behavior and therefore have the same billing factor BF1. f1 may also be interpreted as the portion of non fraudulent customers that statistically have the same electricity consumption behavior with a billing factor of BF2. The non billed energy for the detected fraudulent consumer, may therefore be calculated as:

$$NBE = T * P1 * (BF2 - BF1) \qquad (23)$$

or:

$$NBE = T * Pi * d1 \qquad (24)$$

where d1 = BF2 - BF1 may also be obtained from a function d(BF) as illustrated in Figure 3. Function d (BF) may be calculated mathematically as:

$$d(BF) = f(BFn) - f(BFf) \qquad (25)$$

In practice, however, it would be highly convenient to perform the calculations using microcomputers and standard spreadsheet or data base programs.

Although the described methodology may be interpreted as a statistical approximation, it is conceptually more appropriate than those commonly applied. In the present approach the fraudulent consumer is compared to a statistically equivalent non fraudulent consumer. On the traditional approach it would have been compared to a hypothetical one with arbitrarily selected values of load factors, coincidence factors, etc.

The fair billing methodology, recently proposed, may be summarized as follows:

(1) The statistical distribution functions of the difference in billing factors may be calculated using data from the site surveys. In mathematical terms, see expressions (19), (22) and (25).

(2) After conducting the cost benefit analyses described in section 3.1, proceed with exhaustive site surveys in those consumer classes that justify it.

(3) Past fraudulent consumption of particular customers may be calculated using expression (24).

(4) Special tariffs and fines to discourage further fraudulent consumption and watthour meter alterations may be applied.

3.3 Sample Size Adjustment

To verify the best fit of billing factor experimental values to a Gamma function, it may be convenient to proceed with the "Kolomogorov - Smirnov" test. For that purpose, the cumulative distribution function of billing factors may be calculated as:

$$F(BF) = \int_0^{BF} f(BF)\, dBF \qquad (26)$$

Absolute deviations between experimental and fitted values may then be calculated as:

$$D(BF) = ADS[F'(BF) - F(BF)] \qquad (27)$$

The maximum acceptable value for D[BF] should be 0.27 allowing an error of 1%. Statistical tables may be consulted so as to find the maximum D(BF) value compatible with the desired error. If the resulting error is greater than required, theoretically a new sampling process should be carried out. For that purpose the sample size should be enlarged.

4. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

4.1 Summary

A methodology has been proposed to statistically determine:

(i) The number of fraudulent customers as well as non fraudulent customers, by consumer categories.

(ii) The amount of non-billed energy as a consequence of alterations on watthour meters, per consumer categories.

(iii) A fair billing system, so as to recover losses due to detected infringements.

The proposed methodology may be summarized as follows:

(1) Definition of consumer classes.

(2) Definition of sample sizes per consumer class.

(3) Conduct of site surveys.

(4) Calculation of number of consumers with fraudulent and non fraudulent watthour meters, per consumer class.

(5) Calculation of billing factors for fraudulent and non fraudulent consumers.

(6) Calculation of mean values for billing factors and installed power.

(7) Calculation of the total non-billed energy (TNBE), resulting from alterations in watthour meters.

(8) Cost benefit analyses to prioritize actions for the reduction and control of fraudulent, non-technical losses.

(9) Calculation of the statistical distribution functions for the difference in billing factors.

(10) Proceed with exhaustive site surveys of those consumer classes where justified.

(11) Calculation of historical electricity consumption for each detected fraudulent customers.

(12) Application of special tariffs and fines to discourage further fraudulent consumption.

4.2 Conclusions and Recommendations

From what has been discussed, the following conclusions may be drawn:

(1) There is a need to improve measurement techniques for technical and non technical losses in a reliable and disaggregated manner so as to guide management and decision makers in their efforts to reduce losses in the most cost effective way.

(2) Representative sampling techniques and statistical inference theory, may be effective in detecting, measuring and disaggregating fraudulent non technical losses.

(3) The proposed methodology has been tested at the Empresa de Energia élect'ica de Bogota. Further analyses and tests, in other utilities of the region should be pursued.

Fig 1

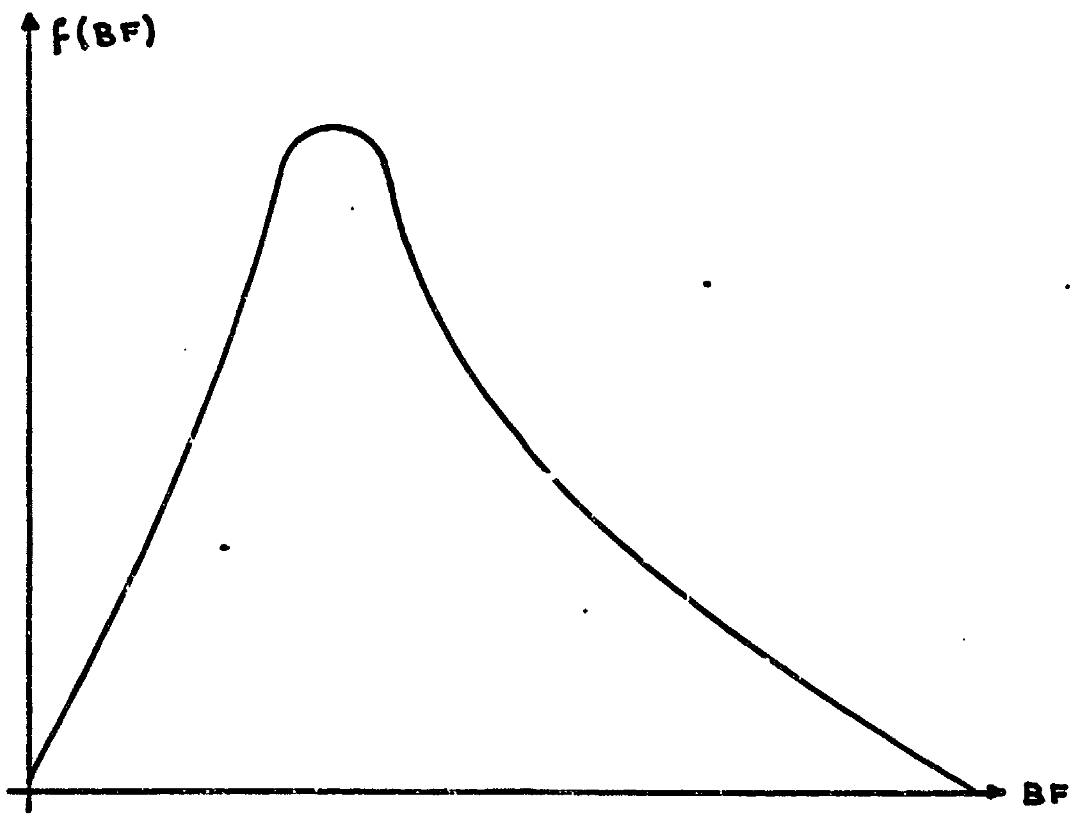


FIGURE 1

Fig 2

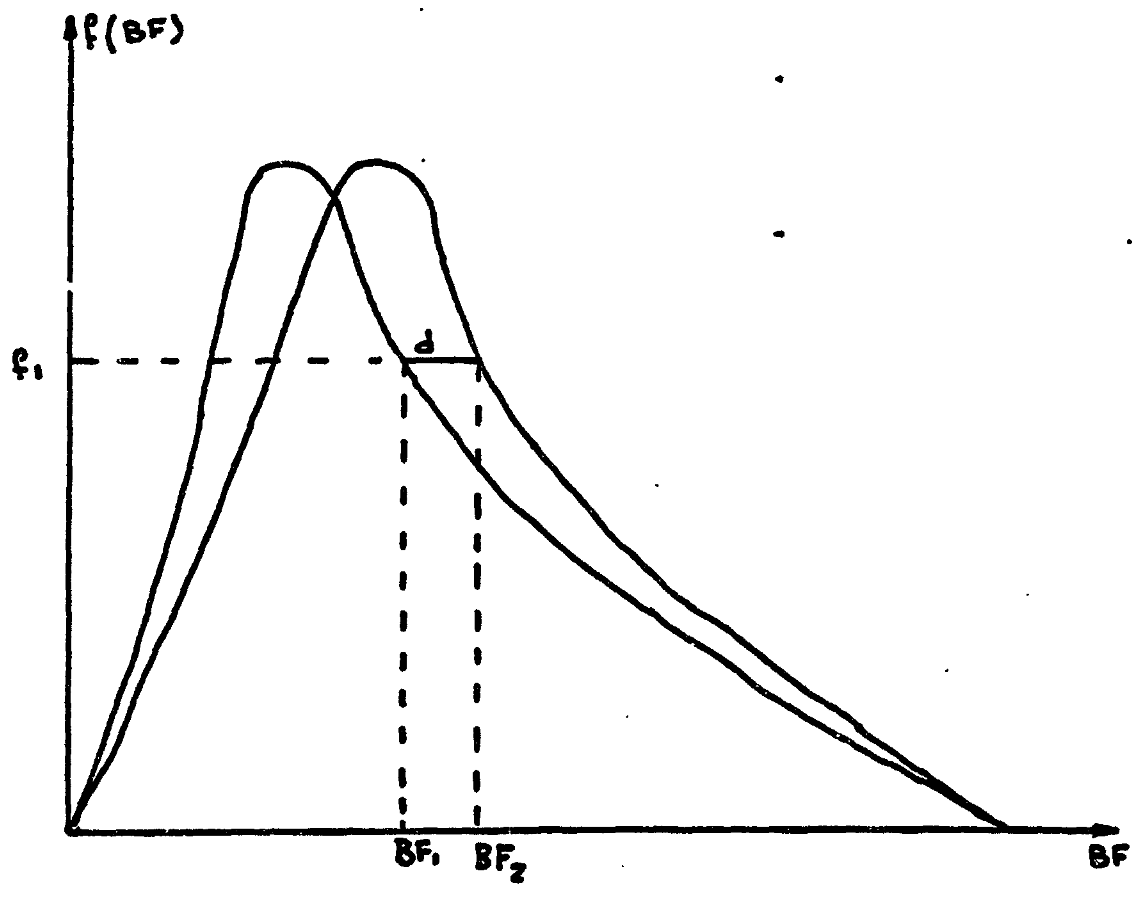


FIGURE 2

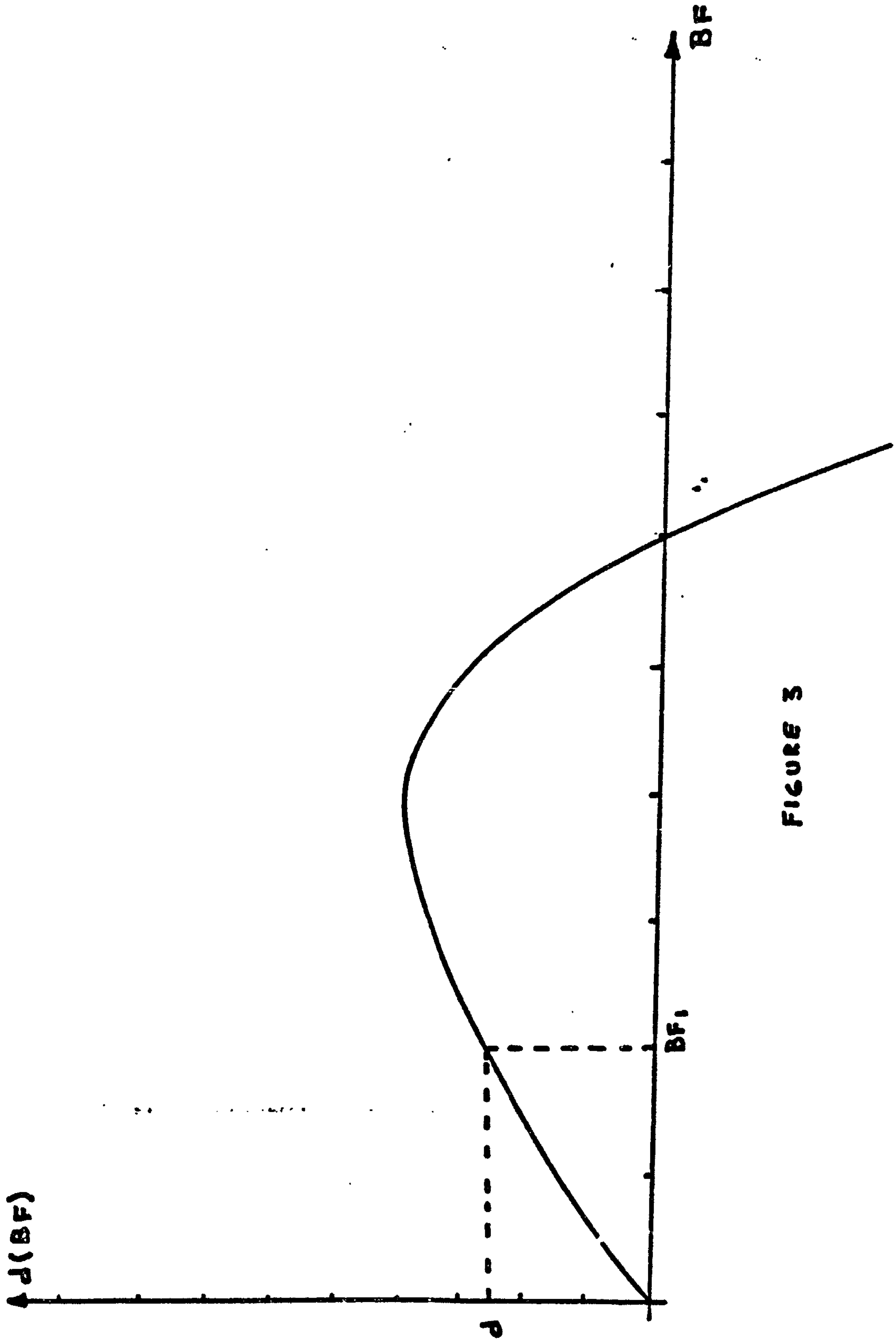


FIGURE 3

CORRECTIVE MEASURES FOR NON-TECHNICAL LOSSES

By

Mr. Willy G. Pacheco
Bolivian Power Company Ltd.

ABSTRACT

Results of work started a year ago by Compania Boliviana de Energia Electrica S.A. - Bolivian Power Company Ltd. on reduction of non-technical losses in the city of La Paz, Bolivia and its surrounding areas are presented. The purpose of this exercise being to contribute to other electric utilities in Latin America and the Caribbean with details of experiences gained in this important and often neglected discipline. Case studies of the various activities carried out thus far are given and results obtained are summarized. Cost/benefit analyses are included and recommendations as to courses of action to be taken by utilities about to engage in similar work are provided.

I. INTRODUCTION

Compania Boliviana de Energia Electrica S.A. - Bolivian Power Company Ltd. (The company) is one of the few remaining private utilities in Latin America. It is owned by shareholders of which approximately 70% reside in the United States and 30% in Canada. It has two divisions, the La Paz Division and the Oruro Division. The La Paz Division generates and distributes electric power to the City of La Paz and surrounding towns and the Oruro Division supplies electric power to mines operated by an agency of the Bolivian Government (Corporation Minera de Bolivia) and sells wholesale power to the Company's subsidiary, Empresa de Luz Electrica de Oruro, S.A. - ELF which distributes electricity to the city of Oruro.

The La Paz Division operates under a non-exclusive franchise dated October 20, 1950 granted by the Municipality of La Paz, which extends to September 1990. The Oruro Division operates under Specific Regulatory Agency Resolution of August 30, 1968. ELF operates under a contract with the Oruro Municipality which extends indefinitely and can be terminated with two years' notice by either party. At present the Company is negotiating a renewal or extension of its franchise with the Bolivian Government and the City of La Paz.

Electricity rates are determined by the Direccion Nacional de Electricidad - DINE, a government entity, whose main functions are to regulate, coordinate and promote the development of the electric industry.

The latest average electricity rates established by DINE for the Company are in the order of US$0.036 per kWh distributed as follows:

Domestic	2.94 US cents per kWh
Commercial	5.47 " "
Industrial	2.97 " "
Street Lighting	3.18 " "
Rural Electrification	1.94 " "

Present and past tariff policies have in general pretended to establish subsidized tariffs to a great majority of the lower income consumers without foreseeing the source of the subsidy. Low tariffs have undoubtedly affected the distribution system expansion of the city of La Paz, particularly in high growth areas in the outskirts of the city where electricity theft has risen. As a result total losses in the city of La Paz system have increased from 12.63% in 1981 to a high of 19.33% recorded in 1987.

This paper will describe the loss reduction efforts started by the Company in March 1988 relating to the reduction of only non-technical losses. Technical losses in the complete generation, transmission and distribution system are also being the subject of a detailed study but results will not be available for another year. It is estimated that technical losses in the La Paz system are approximately 9 to 10 percent of net generation.

II. NON-TECHNICAL LOSSES - REVIEW

In order to establish a guideline of what is to follow a brief reveiw of the definition of "non-technical losses" and a description of all of its components will first be given.

Non-technical losses represent energy consumed for which a power utility does not receive revenues. It consists of all losses absorbed by the utility during its commercial operation, from the time energy is consumed, followed by accurate billing, until full payment is received.

Basically then, there are three major components that form part of non-technical losses. These are:

- Consumption losses - Related to the accuracy with which the utility records the electricity consumed.
- Billing losses - Related to how accurate the billing process is.
- Collection losses - Related to how much of the billed consumption is actually collected.

Consumption Losses

These can be split in two categories:

(a) Non-measured consumption: Refers to consumption which is neither measured nor recorded in the customer-file by the utility and could come from various sources such as illegal connections, inaccurate estimation of consumption, and delays in the installation of metering equipment.

Illegal connections in developing countries, no matter how well administered the utilities may be, are likely to represent the largest component of non-technical losses. Customers connected, without the company's knowledge, consume more energy than necessary. Illegal connections are commonly referred to as electricity theft.

Inaccurate estimation of consumption of those customers connected directly to the distribution system, because of lack of meters, also represent high losses. This is particularly the case in countries that have to import energy meters because these are not manufactured locally and where their purchase depends on the availability of foreign exchange.

Finally delays in the installation of metering equipment on those customers temporarily connected will add to losses as energy consumed until the meter is installed may be incorrectly estimated or not estimated at all.

(b) Measured consumption. Which is measured consumption but not recorded with complete accuracy. In this category the following cases are included: Fraudulent tampering of meters, defective meters, improper hook-up to the distribution system, improper installation of measuring equipment, meters not registered in the customer's file and, management system discrepancies.

Due to management system discrepancies large sources of error occur when the meter reading process is inadequate and does not allow for accurate recording of consumption measured by the meter. Errors in meter constants are common and often reading errors are made because of non-standardization of meters used.

<u>Billing Losses</u>

Billing losses are usually linked to two basic phenomena: Inaccurate information in the customer file and discrepancies in the billing process.

Inaccurate inforamtion in the customer file creates losses if: the information contained in the customers' contract is missing or inaccurate in the billing record, rates applied are incompatible with the service characteristics, equipment installed is different to the one registered and inaccurate notation of changes in the customer dwelling are made which will cause difficulties in the reading of meters and delivery of bills.

Discrepancies in the billing process usually exist if the system does not follow up on non-billed customers or billing does not occur for several periods. Also if customers who benefit from special rates or grants are not controlled. Likewise if billing irregularities or anomalies detected in the billing process are not investigated. Discrepancies in the billing process also arise if bills are corrected without proof or control, if the process cannot ensure that all recorded consumption is billed and the system does not allow for periodic processing of all customer accounts.

Collection Losses

Two elements form part of these losses, unpaid bills and inefficient management of payments. The main reasons for unpaid bills are bills not delivered to the customer, customer inability to pay the bill, and inadequate collection procedures used by the utility. Inefficient managemenet of payments usually result in theft of money by utility employees, loss of revenue due to timing between billing and collection (particularly true in countries with high index of inflation) and inappropriate credit of accounts due to incorrectly identified customers.

Specific details for each case of the three major components of non-technical losses described above are well known and will not be described further. It is important, however, to emphasize that non-technical losses are important to deal with as they have a direct impact on the finances of a utility. Unlike technical losses, non-technical losses are not inevitable, and very often great improvements can be achieved in this area without significant investment of capital. Reduction of non-technical losses is basically a matter of good management. Their target level should be zero.

III. SYSTEM CHARACTERISTICS

General

The generation, transmission and distribution system of the La Paz Division forms part of what is known as the Northern Electrical System of Bolivia. This system is connected to the National Interconnected Grid operated by Empresa Nacional de Electricidad - ENDE. The interconnected grid now serves six of the nine Departments of the country.

Electricity for the La Paz division is generated in eight hydro-electric plants located in Zongo Valley and one in the city of La Paz. Total installed firm generation capacity at present is 113.9 MW>.

Three transmission lines operated at 115 kV and one at 69 kV come out of the Valley feeding a 69 kV ring-circuit that surrounds the city to which 13 distribution substationssn are connected. The transmission network consists of approximately 430 kms of line and also extends to other neighboring towns.

Primary distribution voltage in La Paz is 6.9 kV, 50 Hz. About 455 kms of primary lines and 1,020 kms of secondary lines form part of the distribution network. The secondary voltage is 230/115 volts, although as of 1984 the secondary voltage has been standardized to 220 volts.

Power transformer installed capacity in distribution substations is 152 MVA and distribution transformers installed capacity in primary lines is 240 MVA. With a peak load of 141.11 MVA (127.5 MW) the distribution transformer ratio is approximately 1.70. Generation Load Factor during 1988 was 54.6%.

Consumer and Demand Growth

The La Paz Division has at present approximately 150,000 consumers which according to existing rate structures can be classified in five categories. Table No. 1 lists the five categories and includes data on consumers per category and the distribution of total sales per category for the period April 1988 - March 1989.

Figure No. 1 shows the correspoding percentage of total sales for each group.

Table No. 1

Type	No. of Customers	Consumption (MWh)*
Residential	130,080	269,632
Commercial	19,215	92,632
Industrial	628	85,437
Rural Electrification **	2	9,721
Others ***	187	16,265
Total	150,112	473,687

* 12 month cumulative (March 1988-March 1989)

** Rural Electrification sales are made to two cooperatives which serve approximately 15,000 consumers.

*** Others include small towns, street lighting and exports to the country of Peru.

DISTRIBUTION OF SALES

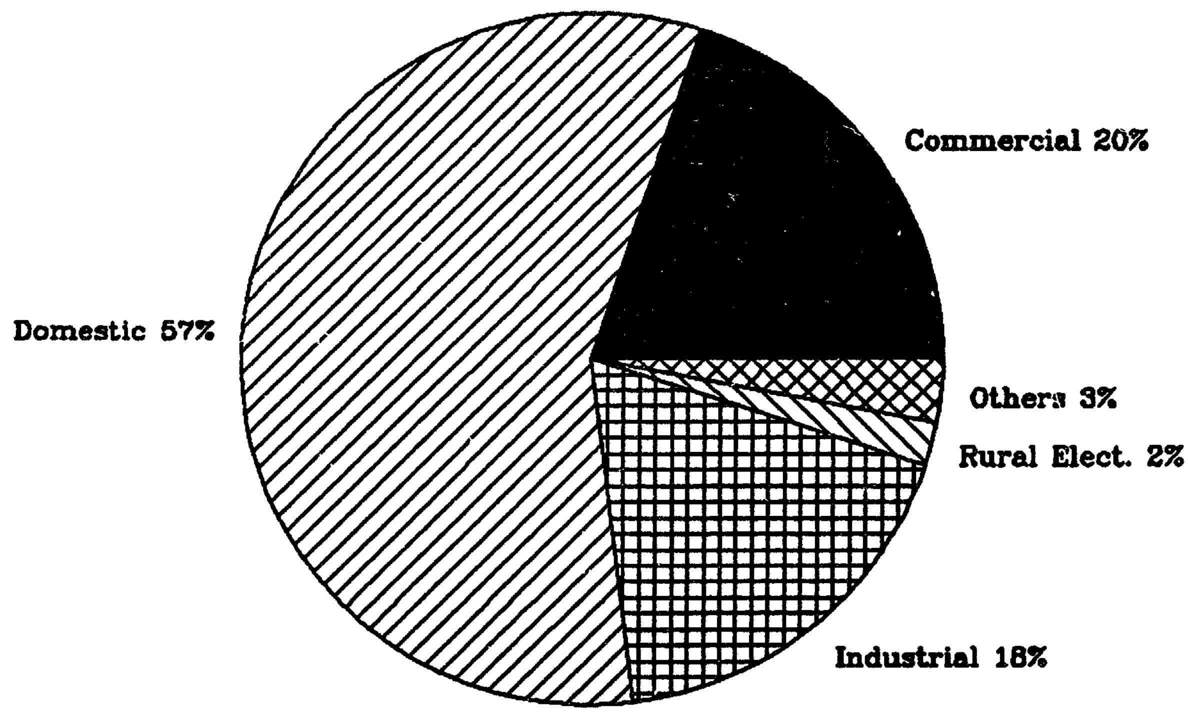


Figure No. 1

Consumer growth had an average increase of 4.14% over the last ten years. Details are plotted in Figure No.2.

Consumer growth has been influenced to a large degree by the country's economy which has had ups and downs characterized by a big recession that started in 1981 and recovered during 1985-86. During 1988 consumer growth has increased sharply to over 6%.

Annual kWh consumption per consumer in the domestic category of the city of La Paz is plotted in Figure No. 3. Over the last decade it has been on average only 1,872 kWh per year, which is equivalent to 156 kWh per month - among the lowest, if not the lowest in Latin America.

Energy Sales for the period 1979-1988 are shown in Figure No. 4. The reduction in sales recorded in 1982 and 1983 were likewise caused by the economic recession. By the year 1985 cumulative inflation had exceeded 14,000%!

Energy Losses - La Paz Division

The devaluation of the Bolivian Peso has had direct effect on losses in the La Paz Division system. Restrictions imposed at the time by the government on availability of foreign exchange limited the Company to provide the necessary resources to attend new requests for service and to carry on with the normal system expansion. As a result consumers in areas near the outskirts of the city were forced to make their own extensions with inadequate and low cost materials which undoubtedly increased technical losses.

Furthermore the social unrest that was created by this condition has had a marked effect on the morality of the low income population making them more aggressive. As a result illegal connections and meter tampering have increased considerably.

Figure No. 5 shows the increase in total losses in the La Paz system during the period 1979-1988. From 1981 when recorded losses were 12.6% these have risen gradually to over 19% by the end of 1987.

The rather chaotic economic situation during this period had also obliged the Company to provide direct (unmetered) services to a large number of consumers in need of service. Lack of meters due to dificulties in obtaining the required foreign exchange to import them was partly the cause. By the end of March 1988 the Company had approximately 8,500 consumers connected directly.

In Figure No. 6 month by month variation of 12 month cumulative losses are plotted from 1986 onward to show the sharp increase in losses. Transmission, distribution and total losses are shown separately for the analysis that is to follow.

Customer Growth — La Paz Division

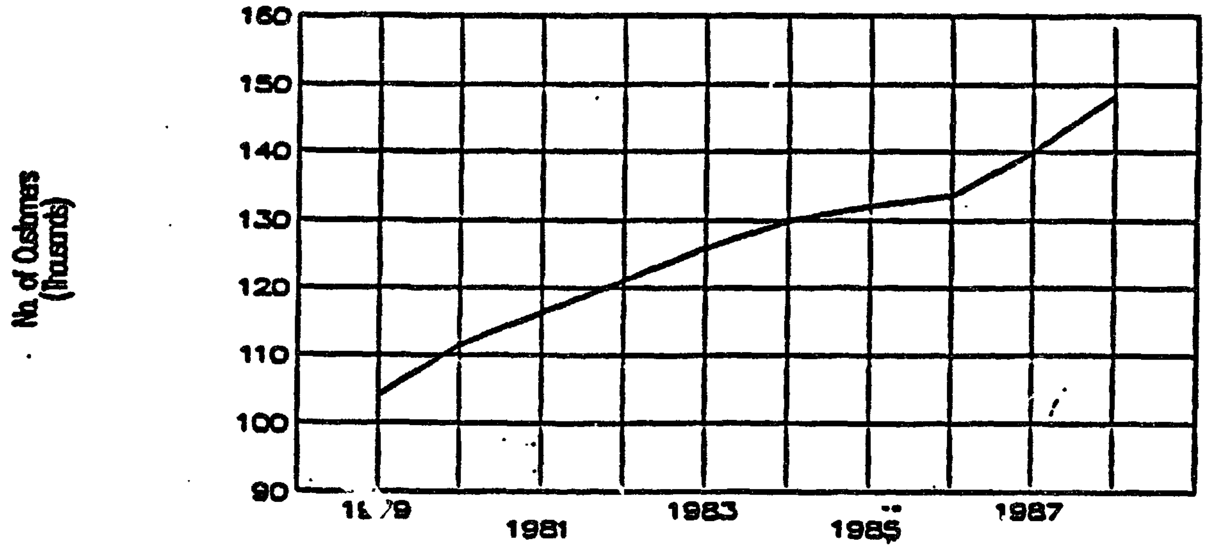


Figure No. 2

Annual Consumption — Domestic

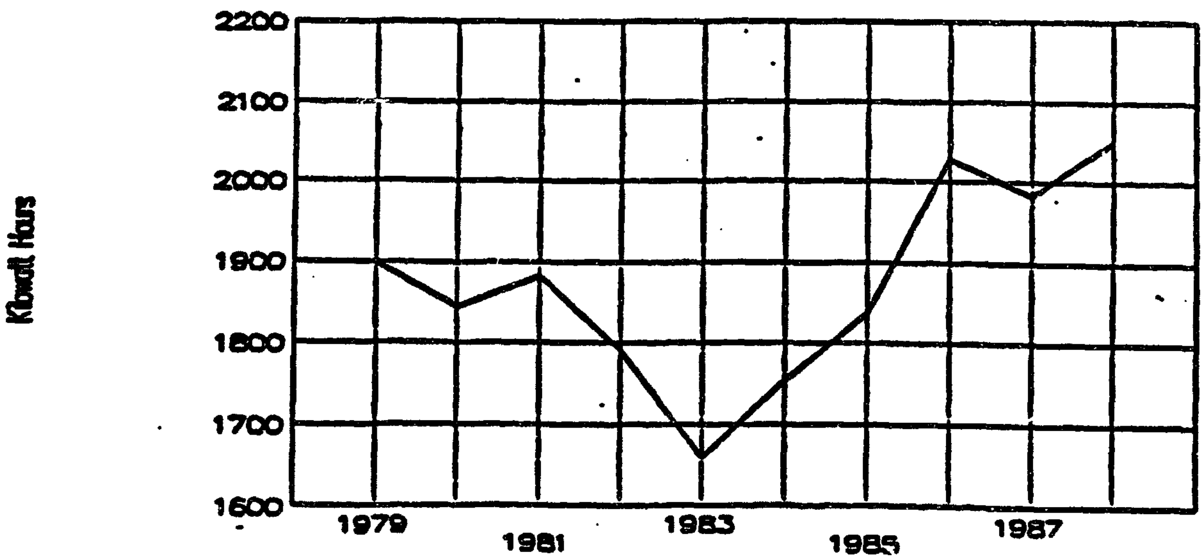


Figure No. 3

Energy Sales — La Paz Division

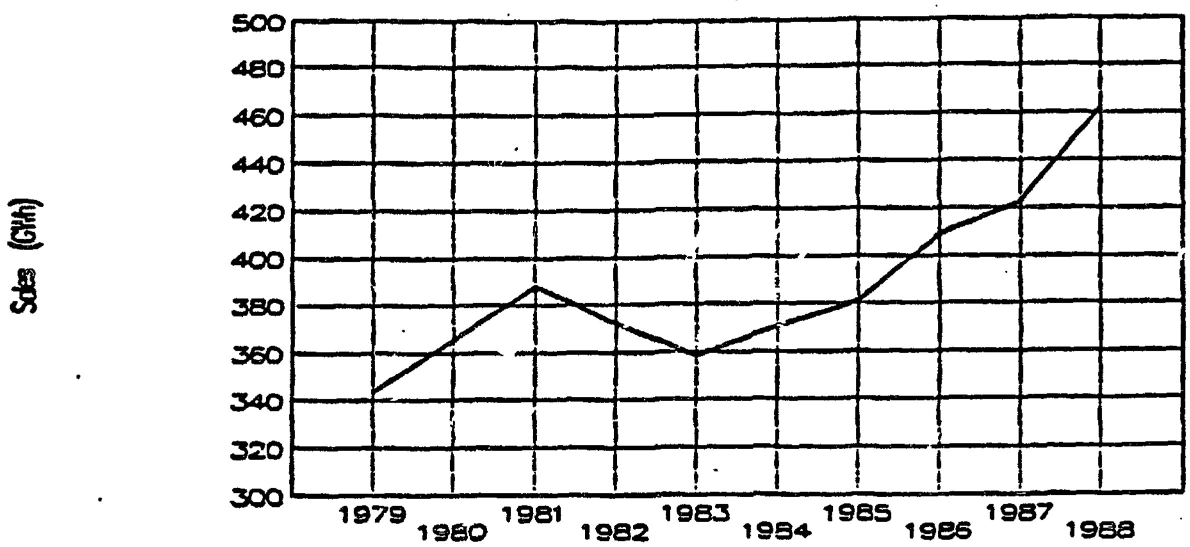


Figure No. 4

Energy Losses — La Paz Division

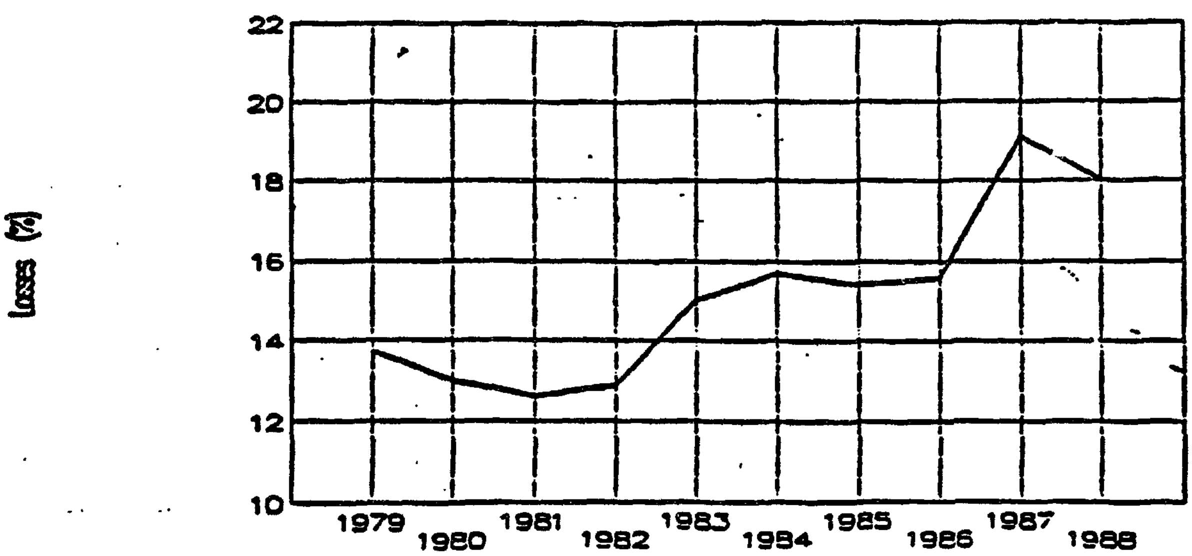


Figure No. 5

Energy Losses – La Paz Division

(12 Month Cumulative)

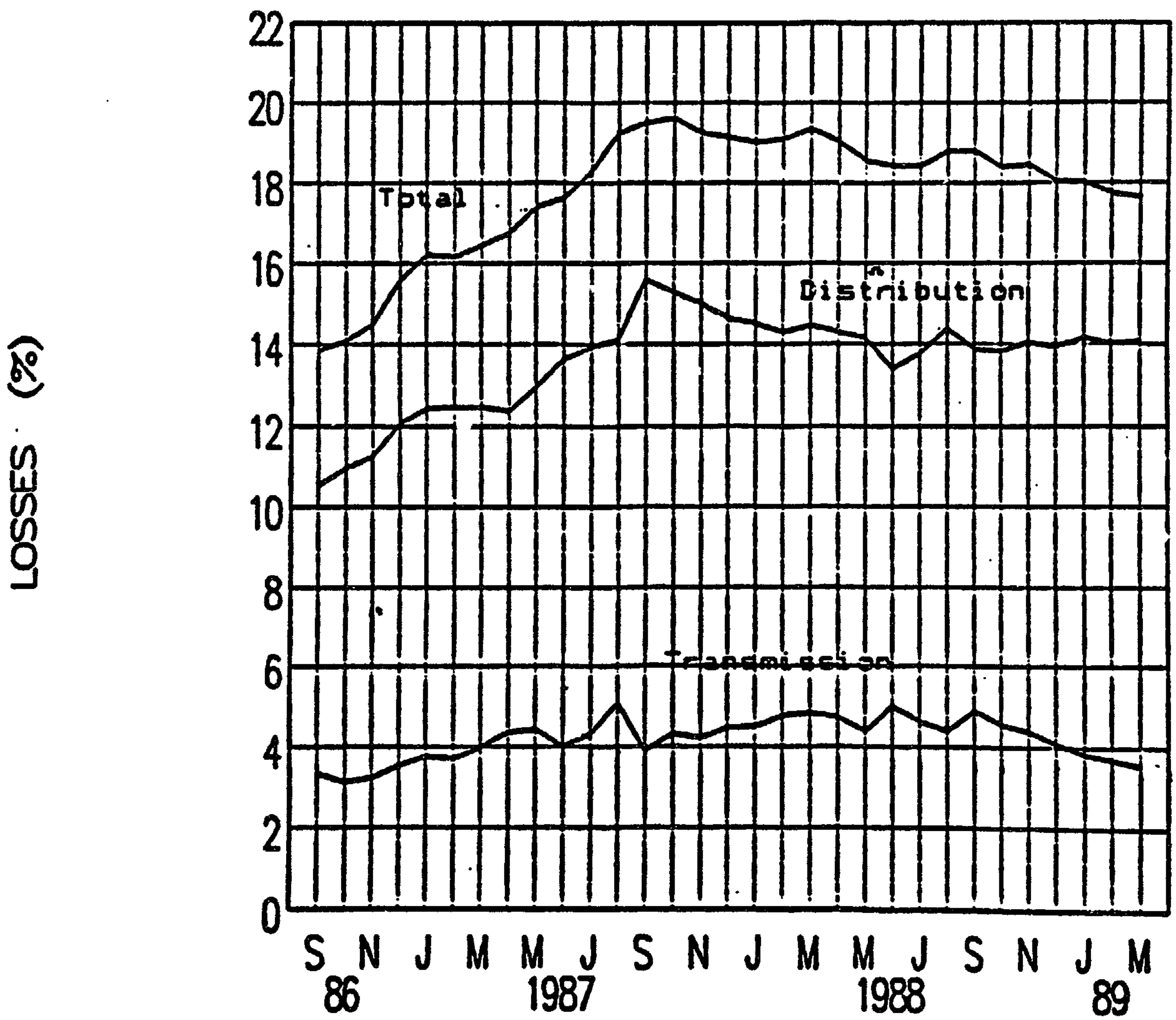


Figure No. 6

IV. LOSS REDUCTION PROGRAM

General

The large increase in losses registered starting towards the end of 1986 induced the company to form a special department with exclusive dedication to the control of losses and their reduction. The specific functions of this section were to:

- Identify major sources of losses.
- Establish a loss reduction program.
- Coordinate with technical divisions of the Company on all loss reduction measures.
- Start a follow-up program on loss control to keep track of improvements made and maintain activities proven effective and economically sound.

The loss reduction unit or "Departmento de Control de Perdidas" started work during March 1988. After a year of operation 12 month cumulative losses were reduced from 19.33% to 17.62% with savings estimated in excess of US$350,000. Present estimates show that two more percentage points can be reduced in non-technical losses by the end of the next twelve month period.

Identification of Sources of Losses

The first step needed before preparing the loss reduction program was to identify the major sources of losses in the La Paz Division system. This required a thorough study of the two main components of losses -- technical and non-technical losses.

(a) Technical Losses

As mentioned earlier technical losses are being the subject of a separate study which is still being carried out. Basically, what is being done is the following:

- The city has been divided into a grid of mosaics 500 x 500 meters each.
- For each mosaic a complete physical inventory of all electrical equipment installed within its boundries is being prepared.
- Each mosaic in turn is being subdivided into a grid 20 x 20 meters.
- All poles structures, primary and/or secondary lines that interconnect them, and distribution transformers are being included.

- This information will form part of a computer data base for which special software is being prepared.
- The ultimate aim being to identify each consumer to a given pole structure and thus be able to carry out transformer management studies, technical loss studies, voltage drop calculations, etc.

This work has been under way for several months and completion is estimated to be by the end of 1989.

b. Non-Technical Losses

Because of its various components the study and loss reduction efforts related to non-technical losses are being carried out jointly by several departments of the Company under the control of the loss reduction unit. Case studies to determine the magnitude of each component were first made to establish priorities and prepare a loss reduction program on non-technical losses under which the loss reduction unit is now operating.

The importance of having clear, concise and periodic information on losses and other pertinent information on system production, consumer growth and sales should be emphasized, as this is basic information needed to carry out any work on loss reduction.

A sample of the Company's monthly statistical report is given on Figure No. 7. All main parameters are given. 12 month cumulative data on generation and sales is included. The latter are useful in determining trends and making comparative analysis because they reduce the effect of seasonal variations, as well as, the time factor involved in the readings of energy meters which because they are not coincidental can introduce appreciable error if only short periods are considered.

For the particular case of the La Paz Division system all distribution substation loads are metered on the low voltage side of the power transformers. Transmission losses are calculated by subtracting the sum of all these metered energy from net generation. Transmission losses, therefore, incldue losses in power transformers.

It is important to point out also that any defective meters or errors in the readings of these particular meters reflect directly on transmission losses because of the way these are calculated.

Distribution losses in the statistical report are calculated by subtracting total energy sales from net generation minus transmission losses.

COMPANIA BOLIVIANA DE ENERGIA ELECTRICA S.A.

BOLIVIAN POWER COMPANY LIMITED

DIVISION - LA PAZ

MONTHLY STATISTICAL REPORT FOR MARCH 1989

	MEGAWATTHOUR GROSS			STATION SERVICE	SYSTEM COINCIDENTAL PEAK DATE: 31 HR: 19.30	
	MONTHLY	YEAR TO DATE	12M THS-CUM	MWh	MW	MVA
ACHACHICALA	1,460.20	4,043.20	17,032.25	9.35	2.50	3.13
ZONGO	746.40	1,034.60	9,331.90	15.70	4.00	5.16
BOTIJLACA	2,064.00	5,677.20	18,697.01	2.64	3.00	3.22
CUTICUCHO	5,592.00	15,500.00	52,927.67	4.08	8.00	8.37
SANTA ROSA No 1	1,943.90	5,444.70	19,931.15	2.24	2.70	3.38
SANTA ROSA No 2	3,667.30	10,511.30	36,755.07	3.35	5.30	5.58
SAINANI	6,942.00	14,031.00	57,390.90	3.06	9.00	9.42
CHUPURAGUI	12,261.60	34,668.00	91,718.23	5.98	23.00	25.13
HARCA	12,650.00	40,874.00	129,254.80	12.27	25.50	26.84
CAHUA	13,494.60	36,583.20	121,586.40	17.53	25.00	29.59
GROSS PRODUCTION	60,822.00	169,247.20	554,625.44		108.00	118.99
STATION SERVICE	76.20	218.72	826.61			
TOTAL TRANSMITTED	60,745.80	169,028.40	553,798.83			
KENKO S/S IMPORT	1,848.00	4,674.00	71,887.34		17.00	19.72
KENKO S/S EXPORT	11,004.00	28,164.00	45,107.40		-.--	-.--
NETT IMPORT	(9,156.00)	(23,490.00)	26,779.94		17.00	19.72
SYSTEM TOTAL	51,589.80	145,538.40	580,578.77	76.20	125.00	138.63
COMPANY USE	393.73	1,160.98	4,576.20			
TRANSM & S/S LOSSES	2,330.44	5,907.97	20,527.94			
DISTRIB N LOSSES	9,548.45	19,446.82	81,787.30			

12 MONTHS SYSTEM DATA
PEAK LOAD MW: 127.50 DATE MARCH/89
LOAD FACTOR: 51.98 %
% SOLD TO SYSTEM TOTAL: 81.59

	MONTHLY	YEAR TO DATE	12M THS-CUM	CUSTOMERS	KWH/CUST (12 M THS CUM)
TOTAL SALES	39,317.10	119,022.71	473,687.33	150,112	3,156
DOMESTIC - D2	830.80	2,702.37	8,624.65	10,488	822
DOMESTIC - D3	4,694.65	15,281.18	61,932.70	53,060	1,167
DOMESTIC - D4	15,303.21	47,931.02	194,299.57	66,344	2,929
DOMESTIC - D5	371.52	1,168.64	4,770.56	188	25,375
TOTAL DOMESTIC	21,200.18	67,083.21	269,632.48	130,080	2,073
GENERAL SMALL-C1	3,563.95	11,022.30	42,370.45	17,812	2,379
GENERAL LARGE-C2	4,043.50	12,090.96	50,261.74	1,403	35,825
INDUSTRIAL SMALL-D	587.86	1,669.31	6,782.26	408	16,623
INDUSTRIAL LARGE-E	5,061.37	13,701.59	56,473.89	217	260,240
SPECIAL CONTRACTS F	2,450.81	7,005.89	22,181.09	3	7,393,693
STREET LIGHTING	1,208.34	3,295.36	13,876.91	5	2,775,382
SMALL TOWNS	26.49	60.96	214.67	180	1,193
RURAL ELECTRIFICATION	900.96	2,407.25	9,721.05	2	4,860,525
CHOJLLA MINE (ENDE)	162.87	435.83	1,019.78	300	4,789
DESAGUADERO (ENDE)	63.77	63.77	63.77	1	63,770
KASANI (ENDE)					
ADJUSTMENTS IJ O/ROI	47.00	106.29	202.25		

MUNICIPAL & GOV'T	MWH	CUSTOMERS
MUNICIPALITY	161.46	62
GOVERNMENT	1,192.22	700

LA PAZ PEAK DEMAND WITHOUT EXPORT TO (ENDE)
DATE: 30 HR: 20:00
MW: 127.50 MVA 141.11

DISTRIB N TRANSFORMERS	No	KVA
COMPANY OWNED	2,677	155,131.5
CUSTOMER OWNED	567	85,728.0
TOTAL	3,244	240,859.5
TRANSFORMER RATIO	1.69	

STREET LIGHTING	No	KW
COMPANY OWNED	4,189	623.04
MUNICIPAL	16,028	2,915.19

Figure No. 7

CASE STUDIES

To provide guidelines and prepare an effective loss reduction program the Loss Reduction Unit began work by carrying out individual case studies to establish the incidence on losses of:

(a) Direct connections (consumers connected to the network by the Company but without meters).

(b) Illegal connections (consumers connected to the network without the Company's knowledge).

(c) Metering errors (either because of defective meters or improperly made installations).

(d) Consumer billing (to check for accuracy of information in consumer files).

a. Direct Connections

As mentioned in Chapter III the number of direct connections to consumers due to lack of meters had increased to over 8,500 by the end of March 1988. This number represented close to 6% of the total number of consumers in the La Paz Division.

Even though energy consumed by these customers was calculated and billed based on installed capacity on each consumer premise, it is a known fact that unmeterd customers tend to consume on the average more energy than they are billed for.

To check this fact a case study was made on Palca Town, a small rural village near the city of La Paz that, out of a total of 191 consumers, had 154 direct connections. Sales to this town are being controlled by metering installed on the main feeder.

Table No. 2 shows details on sales, energy distributed and losses for the last 12 months.

Note the effect on losses of two actions taken by the Company: (a) increase in kWhrs billed to each consumer connected directly, and (b) the installation of meters.

Before July 1988, when losses exceeded 40%, direct connections were being billed 50 kWhrs per month per consumer. Average use of energy per consumer in other rural towns is only 32 kWhrs per month. Starting in July the decision was taken to raise to 80 kWhrs the monthly consumption billed to each consumer that was connected without a meter. Apparent losses which were extremely high due to incorrect estimation of consumption were reduced after this action to about 11%.

Table No. 2: PALCA TOWN SALES AND LOSSES

Month	Consumers With meter	Consumers Without	Sales kWh	Energy Supplied kWh	Losses
April '88	37	154	11627	19600	40.7
May	37	154	11229	18520	40.0
June	36	154	11743	21840	46.2
July	34	159	16069	18000	10.7
Aug	34	161	17732	20000	11.3
Sept.	188	10	10859	10680	-1.7
Oct	191	5	9955	10968	9.2
Nov	193	3	11432	12360	7.5
Dec	190	1	7933	8840	10.3
Jan. '89	190	1	13095	14000	6.5
Feb	179	1	7994	8600	7.1
March	176	1	8863	9600	7.9

Starting in August 1988 meters were installed on all direct connections. Results of these two actions are shown in Figure No. 8 where sales and losses are plotted (3 month cumulative readings).

The drop of energy supplied is worthy of notice. In June 1988 average monthly consumption in this town (with 80% of the consumers with direct connection) was about 115 kWhrs per consumer. After meter were installed average consumption dropped to only 54 kWhrs and losses have dropped to below 8%.

Based on this experience all direct connections are now having meters installed. By April 1989 direct connections have been reduced from 8,500 to less than 200 and work continues to eliminate them completely.

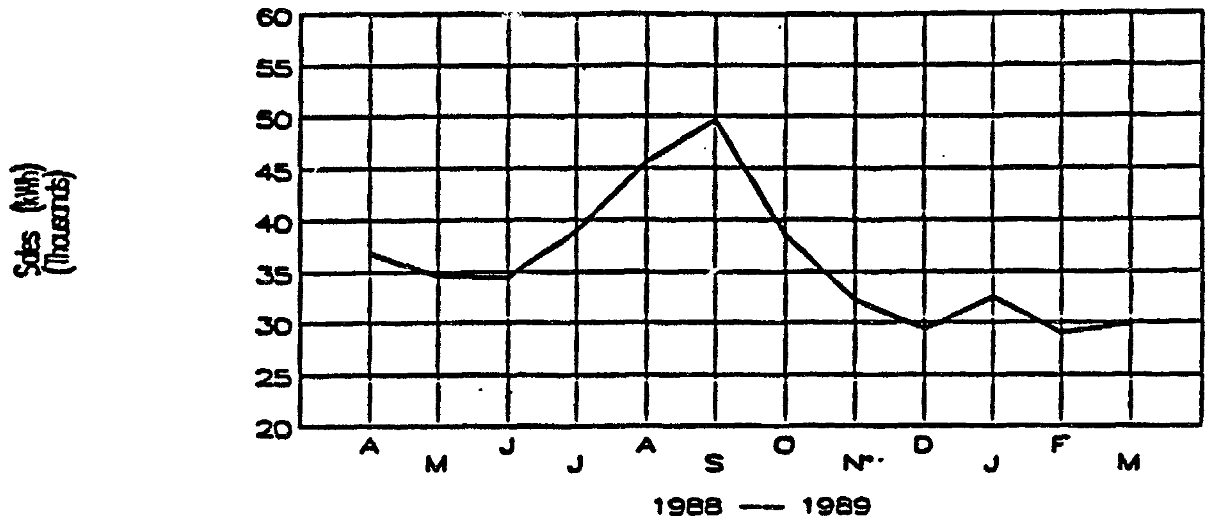
b. Illegal Connections

The detection of illegal connections is more complex as additional metering usually needs to be installed to control losses and this work requires close supervision of the specific area being checked.

The city of La Paz being situated in a narrow valley of the Andes Mountains has limited room for urban expansion. This fact has obliged urban planners to start construction of high-rise apartment buildings and a large portion of the population now dwells in them. This evidence was seen as an opportunity to start a program to detect illegal connections at low cost by installing metering equipment at the service entrance of such buildings and keeping close control on individual consumer meters.

Palca Town Sales

(3 Month Cumulative)



Palca Town Losses

(3 Month Cumulative)

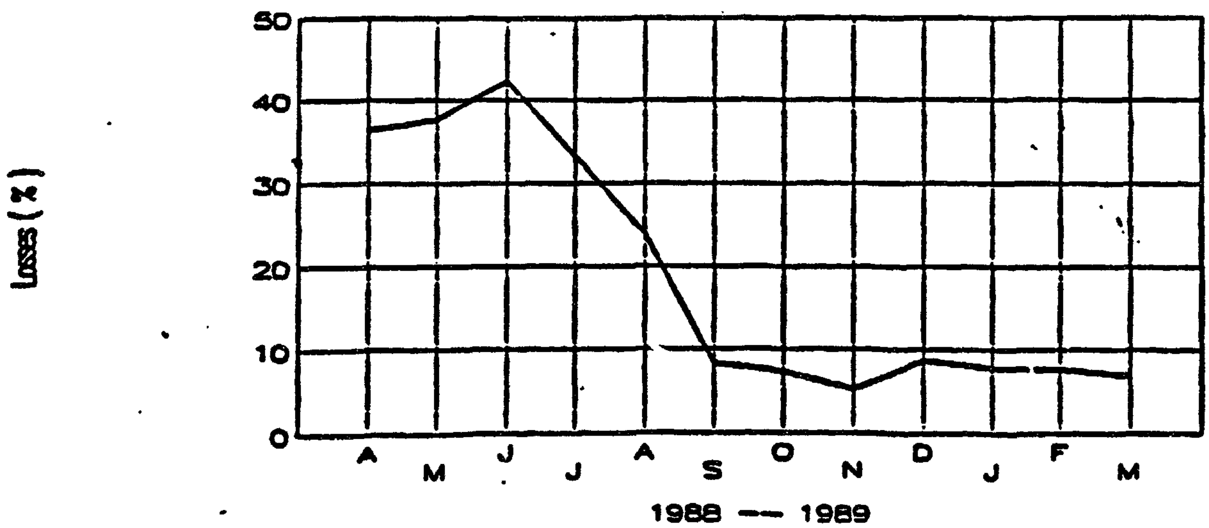


Figure No. 8

Basically this program is being carried out as follows:

- Supply to a building is cut-off while control metering is installed to it.
- All consumer meters are read at this time and special seals are installed to prevent tampering while tests are made.
- Building supply is normalized and after a period of 15 days all meters are re-read after cutting-off once more the supply.
- Based on results obtained individual services are checked, illegal connections (if found) are suspended and action is taken to prevent recurrence.
- A second similar control is made after about two months and results compared.

This program which was started in September 1988 has proven very effective in detecting illegal connections. About 27 buildings have thus far been checked and losses in them have been reduced from an average of 5.5% measured during the first control to 3.15% measured during the second control.

It is estimated that there are over 150 high-rise buildings now in the city. The program will continue until all of them are completely checked.

c. <u>Metering Errors</u>

Measured consumption but not recorded with complete accuracy represent a large component of non-technical losses and have always been of great concern to the Company. Errors are usually due to:

- Defective meters.
- Lack of limited calibration of meters.
- Improper installation of measuring equipment.
- Incorrect application of meter constants on major co sumers metered on the high voltage side.
- The existence of a vast variety of meters (some with four, others with five digits), etc.

One of the major tasks assigned to the Loss Reduction Unit has been the revision and subsequent improvement of all these actions in direct coordination with the Metering and Commercial Departments.

Essentially the program started with a rigorous control on meter installations of all major consumers. Control that included: meter testing, check-up on multiplying constants, and verifying if the load connected agreed with tariffs being applied to each consumer.

Meters installed in generation plants and distribution substations were tested during May - July 1988. In some cases errors in excess of 2% were measured (as against ± 0.05% which is the highest permissible error for these meters according to company standards). Meters with high error were found to correspond to those with many years of service which, due to aging, are difficult to calibrate and have to either be replaced or sent to servicing for a complete overhaul.

Approximately 23% of the meters of all major consumers of the La Paz Division have thus far been checked. Savings due to this action have been estimated to surpass 9.7 GWhrs in sales since the beginning of this program.

d. <u>Consumer Billing</u>

The introduction of all meter records in the main frame computer with which all billing is carried out has helped sort out inconsistencies in the consumer records. This work had started at the end of 1987 and was completed in July 1988.

All meter reading is done on a monthly basis by company employees. Reading routes have now been clearly identified and the loss reduction program has included in its activities the proper training of personnel to carry out this job. Billing frequency is also monthly. Intercalary bills are not emitted. Estimates of consumption are only made in those cases where the meter could not be read because the house was closed in which case a bill is sent based on this estimate and later adjusted when a reading can be made.

Delivery of bills is carried out by a Contractor who also is in charge of disconnecting services that are in arrears. The second consecutive unpaid bill automatically places the consumer in the arrears list.

Inconsistencies between meter and consumer records were found while introducing information in the computer. This has helped detect many cases of incorrect billing, as well as, losses. Also meter changes improperly registered have caused incorrect application of multiplying constants.

The implementation of a now fully computerized system for all commercial operations of the Company has contributed as well to the efficeincy of collection, which at present is only about 45 days from the time the bill is emitted.

<u>Future Work</u>

Based on experience gained during the first year of operation of the Loss Reduction Unit, work will continue on the following fronts:

- Direct connection will be totally eliminated.

- Once all high-rise buildings are checked for illegal connections this work will continue on sectors of the city where low income people live. It is estimated that a very large percentage of non-technical losses correspond to these areas where uncontrolled low voltage line extensions have taken place. Work has already been started to replace these privately owned extensions.

- Meter testing will continue with particular emphasis on the replacement of outdated metering equipment and the implementation of a revised program on meter calibration and statistical inspection of recently acquired units.

- Control of non-billed accounts will be started. This is a subject that has received little attention thus far but, nevertheless, needs action.

- Coordination of activities between the Loss Reduction Unit and the various departments inside the organizational structure of the Company will be improved. This is a must to improve efficiency in any loss reduction work. Personnel working in the Loss Reduction Unit will be increased to improve its operations.

- Efforts will be continued to receive legal support from the Government as at present there are no national laws that deal specifically with the theft of electricity in Bolivia.

V. RECOMMENDATIONS

The reduction of non-technical losses should be a major objective for all electrical utilities, particularly those that have detected high losses, as these have a direct impact on their finances.

To attain a significant reduction of non-technical losses first priority must be given to the optimization of the commercial infrastructure of the utility, even before any loss reduction program is begun. Organizational aspects of the utility's commercial process are essential in the identification and then the control of these losses.

It is indispensable that communications and interrelations inside the organizational structure be excellent and well maintained. There must be frequent contact and discussions between the different units responsible for meter installation, the readings of meters, the billing, rate revisions, collection and all other units that have direct contact with the consumer.

Most utilities today have found that it is justifiable and advisable to create inside their organization a unit, with complete autonomy and freedom of action, whose only job is specifically to detect and control both technical and non-technical losses.

The Loss Reduction Unit formed by Compania Boliviana de Energia Electrica S.A. - Bolivian Power Company Ltd. only a year ago has started a loss reduction program based on specific case studies. Results thus far are encouraging as non-technical losses have been reduced by approximately two percentage points. The unit formed consists of four well trained technicians and one engineer who in direct coordination with other company departments (which have used no more than twenty other employees) have made this program successful.

For those utilities about to engage in similar work regarding the detection and reduction of non-technical losses the following hints and recommendations might prove valuable.

In order of importance the steps to be followed are:

- Make sure that statistical information on generation (if any), sales, and losses is reliable and presented in an easy to read schedule.

- Testing and verification of all important meters used on the calculation of energy delivered to the distribution system should come next. This will ensure that recorded losses are correct and any follow-up action on loss reduction is properly made.

- Start meter testing on major consumers where the likelyhood of large improvements in losses is greatest.

- Revise estimated unmetered consumption. If direct connections exist efforts should be made to have meters installed in them.

- Verify the correctness of 11 consumer files making sure that all basic information dealing with the customers themselves, their location, installation and metering characteristics, conditions of sales, and the service agreed to by them for billing purposes is correct.

- Verify that all consumer meters are being read and bills are emitted in timely fashion.

- Only then start with a program related to the detection of illegal consumers, meter tampering, and electricity theft.

For those interested in loss reduction efforts being carried out at present in other Latin American countries a list of articles that were presented in a Symposium on Control of Losses held in Bogota, Colombia in October 1988 is included in the Bibliography section (Chapter VII items 4 through 12).

Reference to other recent articles (items 13 through 16) to be presented during August 1989 by the Subcommittee of Distribution of Electrical Energy of CIER (Comision de Integracion Electrica Regional) in Cochabamba, Bolivia are also included.

VI. COST/BENEFIT ANALYSIS FOR NON-TECHNICAL LOSS REDUCTION PROGRAMS1/

Review

One of the main reasons for the existence of unacceptably high losses in distribution systems of developing countries has been the decline in financial position of power utilities because governments have prevailed in establishing low electricity tariffs which have led to reduced investment and system maintenance and indirectly stimulated consumption. Frequently electric power utilities are used as instruments of economic policy to fight inflation. Scarcity of foreign exchange resources have, in the majority of cases, also limited system expansion.

Loss reduction projects should not exist if distribution networks would have been adequately planned and received the necessary financial resources. These projects are proof that past policy errors have forced utilities to postpone investments for network rehabilitation and maintenance.

High energy costs and problems in the balance of payments of developing nations have increased interest in energy conservation and reduction of waste in electricity consumption. Loss reduction projects represent an important way of energy conservation and result attractive in developing countries that posses mature electric systems because of their low cost relative to benefits that are gained.

An important rule to remember: Losses become excessive when it is cheaper to reduce them rather than increasing the capacity of the supply. Each kWh lost represents to the country the long marginal cost of supply. Thereby it is worth investing in its reduction only if the cost of its reduction is less than the marginal cost.

The purpose of a cost/benefit analysis is to prove that the benefits of loss reduction are more, or at least equal to, other sacrificed benefits in the economy when assigning resources to the project.

Cost/benefit analysis provides a better way of assigning resources than traditional methods of cost optimization by allowing, first, to compare loss reduction projects with other projects on generation, transmission and distribution; and second, by providing means of ranking projects on electricity distribution with other projects in the country in need of the sometimes limited resources available.

1/ Abstract of an early paper presented at the Symposium of Control of Losses held in Bogota, Colombia on October 1988 by its author Mr. Luis E. Gutierrez (an English version of which is being presented elsewhere in this seminar).

The two types of losses- technical and non-technical, require a somewhat different treatment as cost/benefit analysis is applied to projects, not programs.

Technical losses, on one hand, are primarily economic losses. They are considered to be losses to the national economy and do not just adversely affect the financial health of the utility itself. The energy that is lost as heat in the transmission and distribution system could have satisfied additional (incremental) demand or load. If losses were absent there would be no need to use additional scarce national resources to supply the incremental demand. By reducing technical losses there is less need for power generation and the requirements for transmission and distribution are reduced. Technical losses can be reduced by using better designs, selection and localization of new substations, installation of capacitors, addition or reinforcement of primary and secondary lines, better combination of distribution transformers, etc.

Non-technical losses, on the other hand, are primarily financial losses to the utility. These can be reduced by controlling theft, meter reading errors, and billing and collection improvements. Revenues lost impose a heavy burden on the financial viability. Reducing non-technical losses is one of the best and most cost-effective options to improve the financial position of utilities by providing more revenues. Non-technical losses also affect the economy by distorting the optimal pattern of electricity consumption. Those who do not pay usually consume more. Those who do pay consume less if the higher cost of the non-payment by others is passed on to them through higher tariffs.

When projects for reduction of both technical and non-technical losses are considered for the same distribution network it is convenient to first analyze the later and then, assuming that non-technical losses have been eliminated, technical losses should be examined. This is necessary so as to not overestiamte benefits of technical loss reduction projects as by reducing non-technical losses.

In what follows a description of cost/benefit analysis for only non-technical loss reduction projects will be given. For cost/benefit analysis of technical losses please refer to references listed in the bibliography.

Practical Considerations

As described earlier non-technical loss reduction projects aim at reducing: (a) electricity theft in its various forms, and (b) non-registered use of electricity.

One of the main economic benefits of these projects correspond to savings in resources of generation of energy consumed "free", that once detected will stop being produced. However, since not all unbilled energy will stop being generated (as part of it will continue to be supplied - the difference being that with the project it will now be billed), one must subtract the reduction of consumer surplus resulting from the increase in price. The utility of course will obtain important financial gains by selling energy otherwise lost without the projects.

A second economic benefit results from the increase in demand of existing consumers because of tariff reduction, which will (or should) follow, due to improvements in the financial situation of the utility.

The net benefit of non-technical loss reduction projects can be summarized in the following equality:

[Net Benefit] = [Savings in Resources] - [Reduction of Consumer Surplus] - [Project Costs] (Eq. 1)

To fully understand the components of this equation some explanations follow:

Consumers that receive more energy than they pay (either because of electricity theft or meter malfunction) have a benefit equivalent to what they would be willing to pay for the energy they now consume free. We shall term this energy as WTP_o (where the subscript "o" stands for without a project). When the project is started this benefit becomes a cost to the project; the loss of consumer surplus. Similarly the cost associated to this free energy becomes a savings to the project as it will be shown later.

The net benefit (NB_o) to that economy of continuing with the unbilled free energy can be expressed as:

$$NB_o = WTP_o - mc\ R_o$$

where "mc" is the marginal cost of supply and R_o is the unbilled energy (non-technical losses). The purpose of the project being to reduce the unpaid energy R_o.

The benefits of the porject B_p are given by:

$$NB_p = B_p - NB_p$$

$$NB_p = cm\ [R_p - R_p] - [WTP_p - WTP_p] - C_p$$

which is the same expression as equation (1).

The first term [Savings in Resources] corresponds then to savings due to the reduction of non-technical losses. It is estimated from the reduction in electricity use which in turn is calculated from known values of marginal cost (mc) and unbilled consumption (R_o). The level of consumption of consumers that become "normalized" R_p, if not readily available, has to be calculated from demand curves.

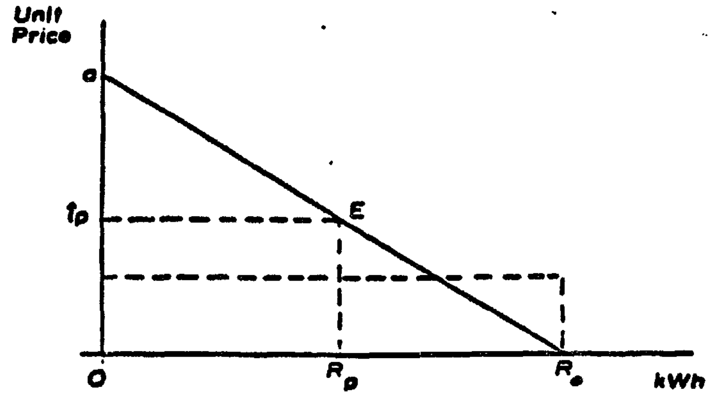


Figure 9

Figure 9 shows a simplified demand curve where for a tariff t_p there is a demand R_p. R_p in the graph would correspond to the increased demand of illegal consumers that don't pay ($t_o = 0$). In this particular case the demand curve can be represented as:

$$t = a - [a/R_o]\ D$$

where

a	=	[t (* - 1)] / *
t	=	marginal tariff for these type of consumers ($0 \leq t \leq a$)
R_o	=	illegal consumption
D	=	demand at price t
*	=	elasticity price of the demand (dD/dt) (t/D)

For those cases where tampered meters are found that only register a fraction of the consumption, or where a defective meter was found, where part of the metered energy (D_x) is paid at the existing tariff (t_p) while the rest (D_x) is not paid. The relevant tariff t_p corresponds to an average price (paid over the total consumption). In both cases, the relevant tariff is weighted for the fraction of the consumption paid and, therefore, higher than zero ($t_o > 0$).

$$t_p = (t_p D_x) \ / \ (D_x + D_x)$$

$$t_o \simeq t_p \ (1/D_x)$$

The equation for the demand in this case can be expressed as:

$$t = a - b\ D$$

where $\quad b = (1/*)\ (t/D)$

Once the demand curve is estimated, the ·· sumption of "normalized" consumers is calculated, substituting "t" for the project tariff t_p, and then solving for the unknown quantity R_p. The [Savings in Resources] component can then be calculated as the product of the marginal cost of replacing the connections mc and the reduction of consumption (R_o - R_p).

The second component of equation 1, [Reduction of consumer surplus], (WTP_o - WTP_p) will also vary depending on the type of unpaid consumption. If it is totally free, or paid in part.

If the tariff is nill (t_o = 0) the loss of consumer surplus is given by:

$$E = 1/2\ t_p\ [R_o - R_p]$$

When the tariff is more than zero ($0 < t_o < t_p$), the loss is calculated from:

$$E = 1/2\ (t_p - t_o\ [R_o - R_p]$$

The last component of equation 1, [Project costs], should include all costs relevant to the project. These can include equipment, systems, and procedures such as: calibration equipment, control meters, service drops, computers for billing and collection, measuring instruments, training and supervision of personnel, design and implementation of procedures to penalize illegal consumers and improve collection, as well as, billing techniques.

Conclusions

The implementation of non-technical loss reduction projects is best done by analyzing separately each type of consumer. It is more rewarding to start with industrial consumers who normally consume more energy and thus provide greater improvement in any loss reduction effort. Likewise consumers with higher income levels should be dealt with first.

A set of recommendations has been provided in Chapter V for those utilities about to engage in similar work. These were based on experiences gained by Compania Boliviana de Energia Electrica S.A. - Bolivian Power Company Limited during the first year of operation of a Loss Reduction Unit formed to carry out this work.

Results thus far have been highly rewarding.

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THE LOSS REDUCTION EXPERIENCE OF THE BARBADOS LIGHT AND POWER COMPANY LIMITED OVER THE PERIOD 1964 - 1988

By

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In order to be assured that we are all thinking in like terms, it may be best to start with , short description of the utility concerned. The Barbados Light and Power Company is the utility which is responsible for the generation, transmission and distribution of all electric power in the Island of Barbados. The island has an area of 431 sq.km. - 166 sq.mls. for those who prefer it that way - and a population of approx. two hundred and fifty three thousand (253,000) people. The whole island is now electrified, that is to say, electricity is available to anyone no matter where he may live on the island. There are two (2) generating sites approx. 5 miles apart connected to a common grid system. All generation is at 11,000 volts. The major portion of the power is stepped-up and transmitted at 24,000 volts to 10 substations at the various load centres in the island. At these substations power is stepped-down to 11,000 volts again, for distribution via some 28 primary feeder circuits. There are 3 distribution primary feeders at 24,000 volts. Distribution is achieved via transformers to provide services at 230/115 volts single phase in the rural and sub-urban areas, and 200/115 volts network in the urban areas.

One of the reasons for stating the above is that there are some utilities - though not in the Caribbean I dare say - who buy their power in bulk, and are happily unconcerned with the effects of generation on their system, provided it is adequate.

Losses in terms of our utility is defined as the difference in the metered quantity of units generated less the quantity of units used for generation (station services) and the metered quantity of units sold. This may be more aptly put as net generation - i.e. that energy which leaves the 11KV generator bus/bars for transmission and distribution - and the cumulative quantity of metered energy sold. System losses are generally expressed as a percentage of net energy generated.

Having defined losses as net energy generated minus quantity of sold energy, we may now look at the reasons for losses in an electric utility system; determine how these losses are generated; and explain how we at B.L. & P. endeavour to keep these losses low.

Losses may conveniently be divided into two categories - Technical losses and Non-technical losses.

TECHNICAL LOSSES

Technical losses are due to the laws of physics, and can be thus accounted for. Engineering-wise these are therefore measurable and controllable. I am afraid that technical losses will never be completely reduced to zero - Superconductivity or no Superconductivity. The criteria for technical losses may be categorized under the following sub-headings.

TRANSMISSION

Voltage
Conductor sizing and spacing

SUBSTATIONS

Siting
Layout

PRIMARY FEEDERS

Lengths
Voltage
Conductor sizing
P.F. Correction
Regulation

DISTRIBUTION TRANSFORMERS

Small transformers and short secondaries
Versus
Large transformers and long secondaries

Consideration of loss analysis in bid evaluation

SECONDARY LINES

Conductor sizing
Lengths

SERVICE DROPS

Conductor sizing
Lengths

METERS

Accuracy

In the theoretical sense we are all very familiar with the underlying precepts governing the above. Most have to do with Ohms Law, I^2R, RHO-L/A, reactive power etc., all covered in the basic principles of electricity which have been crammed into us at one time or another. In the practical design of a viable electric utility system however it becomes slightly more complicated as ponderance has to be given to such things as optimization, standardisation, least cost, quality of service to consumers, affordability, and a whole host of other economic and sociological factors.

This brings us every opportunity to talk briefly about the other category of losses posited -

NON-TECHNICAL LOSSES

These are in the main those losses which are related to the logistics of management; the efficacy of the management policies deployed; and the efficiency with which these are implemented. In other words, these losses are usually subjected to the vagaries of human failings and the systems which are put in place to control the same.
Some sub-headings here may be as follows:-

Meter reading
Service Inspections
Exception Reports
Contraband or theft

This last - theft - is possibly the most direct form of loss a utility suffers. It is extremely difficult to detect at times, depending on the ingenuity of the thief. Many a saga can be written based on the romance - "Meter Inspector versus Contraband".

You will note that I have only addressed those non-technical losses which will affect the metered quantity of energy sold, i.e. through inefficiency of inspectors, meter readers - or through deliberate energy diversion. Losses due to administrative problems and poor business principles I consider outside the ambit of my terms of reference. In point of fact I doubt that I will be able to concentrate very much in this paper on non-technical losses, interesting though that subject is, except maybe during question time. I have a feeling that the deliberations of this seminar are predominantly on the control of technical losses.

It is in the control of technical losses that the engineer - whether he be planning, transmission or distribution makes his greatest contribution to an efficient electric utility system. To keep within the confines of my terms of reference, I will put the question for you. "What do we at B.L. & P. do to be in the happy situation where the "losses" on our system are the lowest in the Caribbean, and compare very favourably with utilities in some of the more developed countries?

Let us look at the chart of "losses" plotted against net generation, starting around 1964 (Fig.1). This was a time of very high load growth - greater than 15% per annum compounding. You will note the high level of losses endured at the time. I joined the Company in early 1965, and I remember well. The installed capacity was 20MW, with a peak load of 14MW. There was 8MW of generation at 11KV and the remainder was at 3.3KV. There was still a certain amount of 3.3KV distribution. The programme at the time was to move away from 3.3KV distribution and to convert completely to 11KV distribution. With this higher voltage level, ampacities were reduced for the same power requirements, and we achieved a constant reduction in losses as this programme progressed. All generation additions were now made at a busbar voltage of 11,000 volts.

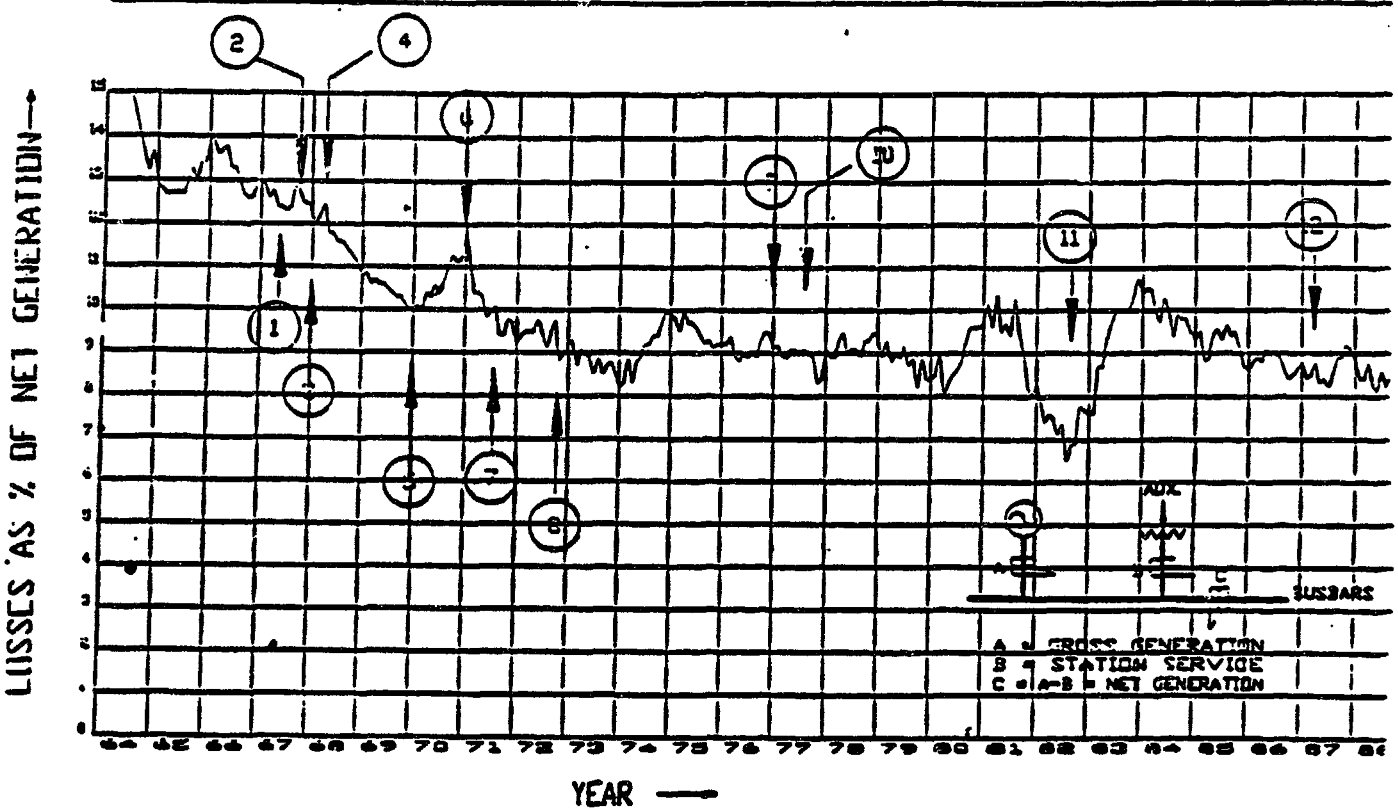
Fig 1

THE BARBADOS LIGHT & POWER CO. LTD.

LINE LOSSES 1964 - 1988

KEY

(1)	SP.GDN UNITS 1&2 - 4.4 MW	(7)	SP.GDN UNITS 8&9 -9.2 MW
(2)	SP.GDN UNITS 3,4&5 -6.6 MW	(8)	CENTRAL 24KV SUBSTATION
(3)	ST.THOMAS 24KV SUBSTATION	(9)	SP.GDN UNITS S2 -20 MW
(4)	OLD WORKS 24KV SUBSTATION	(10)	SP.GDN UNITS S1 -20 MW
(5)	SP.GDN UNITS 6&7 -9.2 MW	(11)	SP.GDN UNITS 10&11 -25 MW
(6)	INACCURATE METER ON AUXILIARIES	(12)	SP.GDN UNITS 12 -12.5 MW



I must admit that during those years little effort was put into Loss Reduction per se. The price of oil was low compared with post 1974 prices. The only attempt at Loss Reduction was indirect, as it pertained primarily to the maintenance of voltage levels along the line, and at customer loads. I speak now specifically to the installation of capacitors. As the system expanded to the northern and eastern parishes, a higher voltage was required, and in the mid 60's the first 11KV pole-mounted capacitors were installed in St. Peter to obtain better voltage regulation. Progressively more capacitance was installed on all 11KV feeders as voltage levels dictated.

The primary reasons for capacitor installations are:-

1. Reduction of I^2R losses
2. Improved Voltage Regulation
3. Recovery of system capacity resulting in deferred capital expenditure for expansion.
4. Releasing circuit capacity for application of additional load. Over the years B.L. & P. have maintained a planned programme of installing capacitor banks on our system. At the present time, there are some 20MVar of capacitance installed.

In mid 1979, our first substation was built, located somewhat to the West of the centre of the island. It was fed by 9KM of 336MCM aluminum line at 24KV, stepped down to 11KV to feed surrounding areas. One year later, a similar substation was built at Old Works, to cater for the load growth in the southern areas. Looking at our chart (Fig. 1) we note the dramatic drop in our losses - some 2-1/2 percentage points.

In system design, siting of substations cannot be done willy-nilly. Substations must be located as near as possible to the load centres to be most effective, for obvious reasons. The Substation is also a very practical position for installing regulation facilities on the system. All of our substations are equipped with automatic voltage regulators.

Between 1970 and 1971 we see a departure from the usual trend, and our losses appear to increase. This turns out to be a false picture and is due to a defective meter on our auxiliaries. This made the net generation to appear higher, and a subsequent high loss relationship. Meter accuracy you see is very important. This will be addressed more fully in a later section. Generation is added as load growth demands, and in 1972 a third substation at Central was built fed by two lines - approx. 7.5KM of 336MCM aluminum O/H wire. Our losses went down to the impressive low of less than 9%.

Previous to this in 1969, a system expansion study was done and was based on forecast load growth. It was recommended that 69KV transmission lines be introduced, and some of the 11KV distribution feeders be converted to 24KV operation. The higher voltage levels would increase line capacities and reduce line losses. A few of our distribution feeders have been converted to 24KV, but because the load growth has been lower than that which was forecast, the 69KV transmission project was deferred.

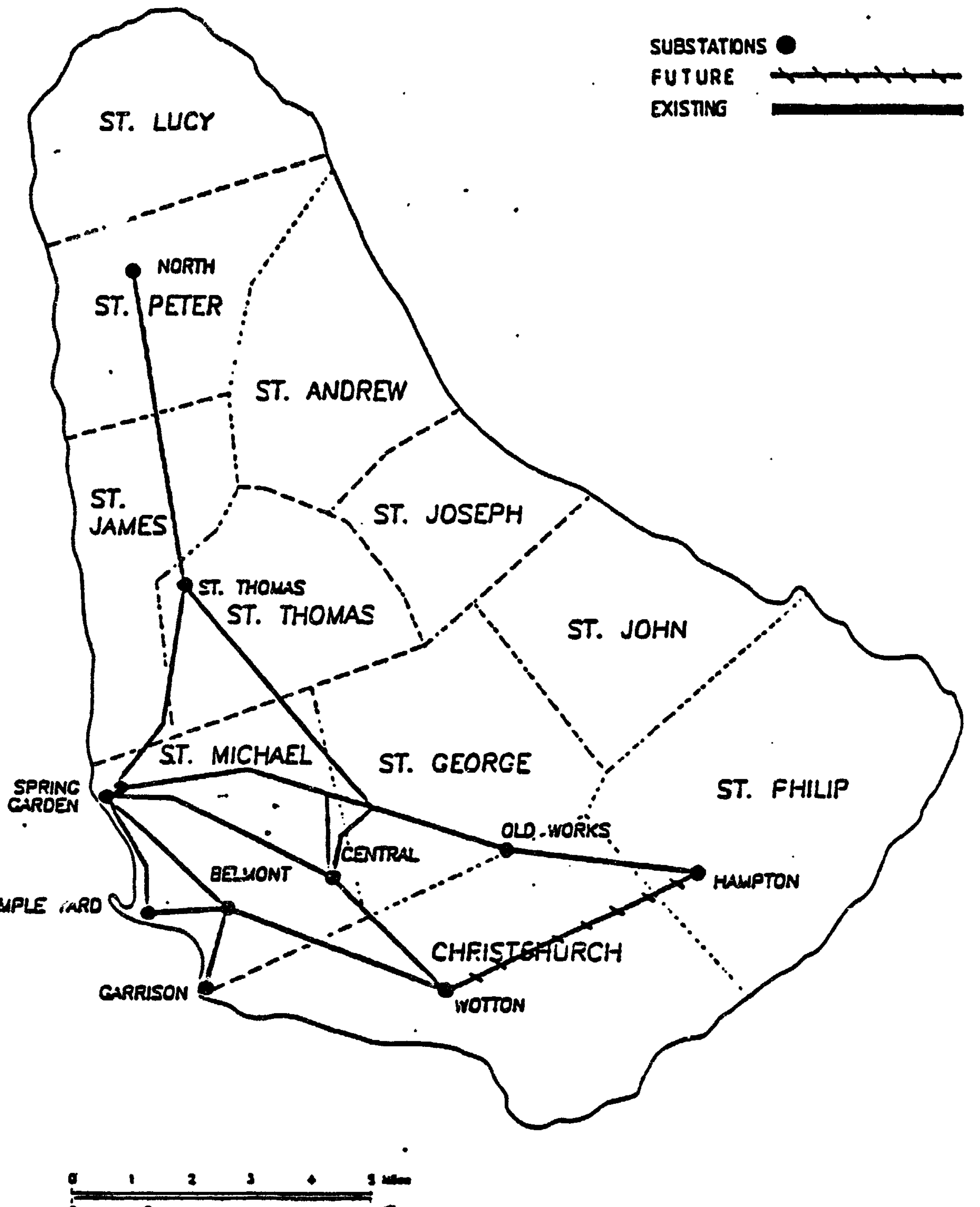
So far we have noted the certain influences which impact on losses resulting from load growth:- Increase in generated voltage; transmitting into load centres at higher voltage levels; siting of substations; and regulation on primary feeders. We have also alluded to the effect of installing capacitors on distribution feeders.

It would serve little purpose to give a dated historical account of the growth of the Barbados System. I will just acquaint you of our current position (Fig. 2). We presently have an installed capacity of 132 MW, a peak demand of some 79MW. We have a 24KV grid system linking 10 substations from each of which power is distributed at 11KV or 24KV. Our present losses are in the vicinity of 8% of our net generation.

Let us now look at some of the other aspects of distribution engineering which affect losses. Conductor sizing is an obvious one. Over the years approx. 20% of my routine capital expenditure was on an item we call "strengthening" which is in the main reconductoring of existing H.T. & L.T. mains, always to a larger conductor size. This year we budget to spend some $3.8 million on this item. To date we have standardized on 336 MCM for all our 3 phase mains and 1/0 Al. for H.T. radials and L.T. mains. This is an uprate from the No. 3 copper and the No. 2 Al. which was previously prevalent. The greater part of our transmission lines is built at 795 MCM Al. or 500 MCM copper. Our cable for service drops has also been uprated. Whereas as recent as 3 years ago the average service drop to a house was in No. 10 concentric copper. We have now standardized on a No. 8 duplex copper cable.

Let us now look at what I tend to consider the most important item in the distribution transformation set-up - the distribution transformer. Now each distribution transformer can be considered in the same light as a substation in our transmission system with respect to losses. I know that there are some systems in the Caribbean which use large 3-phase transformers and long secondaries - with all the attendant losses both in the transformer and along the lines. We opt for several small transformers with short secondaries. I remember visiting one area in the United States and it appeared to me that a transformer was utilized to serve at the most two dwellings. We haven't got to that situation in Barbados yet, because the load in the average home is too small - but we are getting there. It may be of interest too to note the type of distribution systems we use in Barbados - Rural and Sub-urban domestic loads are fed by single phase H.T. distribution. A radial of one H.T. phase is run into a village - for instance - with a continuous neutral wire which is earthed at multiple points along the line. Single phase distribution transformers are then installed rated at 6.35KV primary 230/115 volts secondary. We find this a very convenient and more economical method of supplying rural domestic loads.

Before I leave distribution transformers, I will touch briefly on losses inside the transformer. This depends to a great extent on the design of the transformer, materials used etc. Some transformers have higher per unit losses than others. To try to control this, what we do is to use the loss analysis quoted by the manufacturer in his tender as one of the criteria in the bid evaluations.



24000 VOLTS TRANSMISSION SYSTEM

FIG 2.

THE BARBADOS
LIGHT & POWER
COMPANY LIMITED

And now we come to the most important little fellow in the whole system - The Meter - The scale - The interface between ourselves and the customer - The balance on which hangs our integrity on the one hand and losing our marbles on the other.

Accuracy of registration is paramount. We at B.L. & P. try to maintain certain standards for our meter accuracy. For domestic meters +/- 2% tested against a sub-standard meter is the acceptable band. For commercial meters +/- 1% and for industrial meters +/- 0.6% is acceptable. We have a 10 year meter test programme which ensures that each meter is brought in for test at least every 10 years. New meters are sample tested - 1 in every 10 or 20 - before installation.

So far we have looked at the aspects of technical losses which can be controlled and measured - the results of design as it were. What sometimes tend to be neglected are those losses produced in the field by the artisans, i.e. the people who construct and maintain the system. It has got to be stressed that every connection out there on that system, every joint, every jumper, is a heat point and a potential loss of power. There are millions of these on any system - in the substations , along the line, at the transformers, on the service drops, everywhere.

Constant training and good supervision of the linesmen is a must if these losses and consequent failures are to be kept as low as possible. Do we train the linesmen not only how to make good crimps, but also why it is important that he does so? Training is an infrastructural investment of which the returns are not easily measurable, there are so many aspects of it. The aspect that is pertinent to our particular case is the degree to which it affects I^2R losses on our systems. Standardization does help to simplify training.

I will now briefly talk on the subject of non-technical losses, and what we do to control these. As has been hinted earlier, the greatest part of these losses are due to energy diversion. Training of the meter readers and inspectors is important. Detecting diversion is a skill that is acquired mainly by experience. These days with computerized facilities, exception reports form a useful tool, by providing the first reason for suspicion of diversion. Our billing has been computerized for several years now, and the exception report is institutionalized. The exception report also helps to detect technical losses, such as those due to the blowing of an H.T. fuse in a metering P.T. In this case only half the power is registered by the meter. There is no way of knowing if the H.T. fuse of the metering outfit of the Hilton Hotel for example is blown. Think of the loss that would result if this was not detected for a year, say.

Our experience in Barbados is not particularly bad with respect to current diversion. The integrity of the large users is generally high. I can only remember one case where the underground feed at a certain hotel - which is now out of business - was intercepted so that the feed to the swimming pool was diverted before the meter. People are generally deterred from contraband by the inconvenience inflicted if detected. What we do is to withdraw meter and service, and insist that the customer gets an inspection from the G.E.E. before service is reconnected. This can be a lengthy business. He runs the risk of having to re-wire his entire dwelling. Also the neighbours soon get to know why he was disconnected.

To summarize,

We have looked at some of the many possible ways in which losses are generated in an electric utility system. I am absolutely sure I have not exhausted them all, and I dare say that some of you may be familiar with losses generated as a result of factors other than those I have mentioned. I believe though I have covered the main general ones. I have also tried to outline how we at B.L. & P. have tackled the problem of controlling and keeping these losses low. There is one aspect of our operations to which I have alluded only indirectly. I speak now to the importance of planning and forecasting. In this day and age when every engineer has a computer on his desk - or nearly every one - what would have been a miracle in the 60's is now an every day experience. Programmes and system models are available where-by load-flows, voltage levels, losses , every possible parameter necessary can be calculated for varying conditions. Optimum conditions are now easily forecast. A more significant percentage of engineering is now being done in the planning stages than here-to-fore, and the results more accurately designed. We at B.L. & P. have over the last 25 years commissioned about 5 expansion studies, generally concentrating on five year periods. These have been done by foreign consultants. Even the smallest utility today will find this type of planning an absolute necessity to avoid some of the problems we experienced in the early sixties including as has been seen high I^2R losses.

The importance of planning in the utility industry could be the subject of another paper.

I hope you have found what I have had to say interesting and I look forward to your questions.

MICROCOMPUTER CALCULATION OF TECHNICAL LOSSES

by

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I. INTRODUCTION

The increasing scarcity of new foreign capital and the effects of debt burden on the economies of many developing countries in the later 1980s have resulted in inward looks on strategies to improve the efficiency of existing infrastructures in the economies of these nations. The electric utility sector's high dependence on foreign exchange for operations and purchase of parts is a prime area for efficiency gains through loss reduction.

Electric power loss reduction is very beneficial both to the utility and the economy. Loss reduction defers investment in new electric plants. Foreign exchange saved from new plants, operations and maintenance can be used alternatively in other sectors of the economy. Economic benefits from reduced power outages could increase great domestic product even marginally. Completion of a loss reduction program could also have a positive effect on the utility's cash flow from sales of the saved power. Thus those utilities that may break even in the future are the ones that will be willing to do some "house cleaning" such as establishing and continuing loss reduction programs.

Modern technology has enhanced the use of microcomputers as a tool in technical loss estimation. Their use in the electric utility industry is spreading, especially with integrated software packages which can do loss calculations, billing, accounting, inventory control, load and demand forecasting as well. The capabilities of these microcomputers can greatly improve the operations of any utility company.

This paper describes how the microcomputer can be used in technical loss analysis. Section II presents the background and some relationships between the variables used in the case study in Section IV. The hardware and software requirements for some of the technical loss reduction packages are given in Section III. A case study of a hypothetical network is demonstrated in Section IV using Scott and Scott's Distribution Primary Analysis and Graphics (DPA/G) software program. 1/

1/ Scott and Scott is one of several private suppliers of computer software for electricity distribution loss reduction.

II. ELECTRIC LOSS MODELING

The basic principle of electric system loss modeling using the microcomputer involves

(i) the definition of the network area targeted for technical loss analysis;

(ii) division of the network into unique feeders;

(iii) establishment of database for feeders, conductors, nodes, sections, loads and equipment; and

(iv) execution of computer loss estimating programs and analysing the output.

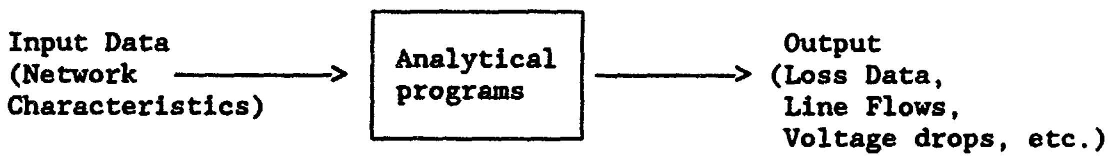


Figure 1: ELECTRIC TECHNICAL LOSS MODELING

Figure 1 shows an illustration of electric loss modeling. The network characteristics are collected and processed by the analytical programs. Loss data, line flows, voltage drop and levels are some of the outputs of the analysis.

Database creation can be accomplished manually by typing the data directly into the computer terminal or automatically through digitizers and customers' billing records in integrated software packages. Real time data acquisition systems like Power-Donut (developed by NITECH) can collect, digitize and transmit transmission and distribution line operating parameters, including load, to a remote station. This station can either process and store the information, or retransmit it through telephone lines to an analysis center. The data files so created are used in desired loss analysis using standard electrical science equations and numerical methods. The equations are iterated until a pre-selected convergence factor is achieved.

The analysis performed includes load flows, switching, load balancing among phases, capacitor size and location optimization, economic loading of conductors and transformers, short circuit, reconductoring, and transformer evaluation.

1. Load Flows and Losses: A network supplied by two or more substations has different ways of supplying the loads connected to it. Line sections provide equalizing means through which excess power is transported to different loads. For example:

Consider the equivalent circuit of a hypothetical network (Figure 2) with node curent I_A, Voltage V_A and admittance Y.

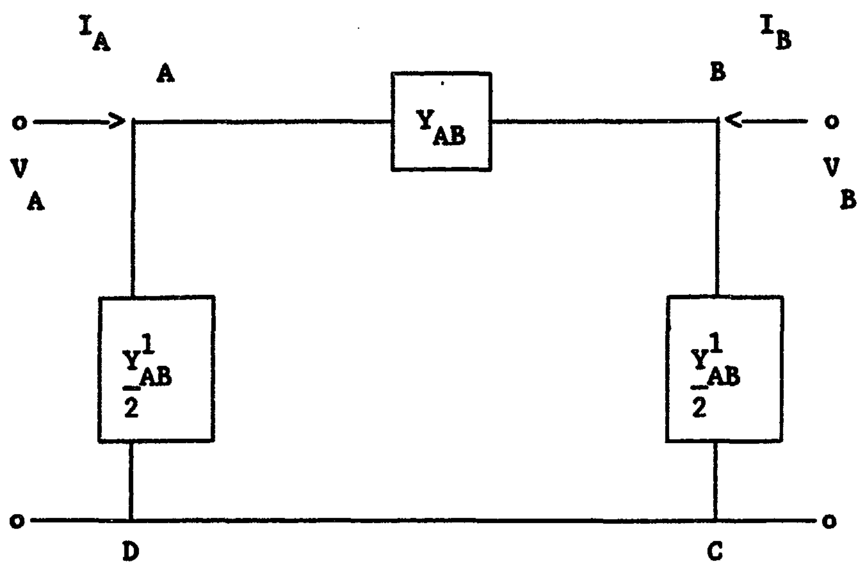


Figure 2 : Line Flow Network

1. Current

(a) At node A

$$I_A = (V_A - V_B)\, Y_{AB} + V_A \frac{Y^1_{AB}}{2} \qquad (1)$$

(b) On section AB

$$I_{AB} = (V_A - V_B)\, Y_{AB} \qquad (2)$$

(c) On section AD

$$I_{AD} = \frac{1}{2} V_A \; Y^1_{AB} \qquad (3)$$

2. Voltage

(a) At node A

$$V_A = V_{AB} + V_B \qquad (4)$$

(b) Drop on Section AB = $V_A - V_B$ (5)

3. <u>Load (Power) Flow</u>

(a) From node A to B:

$$P_{AB} - jQ_{AB} \quad (6)$$

where
P_{AB} = real power
Q_{AB} = reactive power

(b) From node B to A : $P_{BA} - jQ_{BA}$ (7)

where
P_{BA} = real power

Q_{BA} = reactive power

(c) Power loss between node A and B: Algebraic Sum of

$$P_{AB} - jQ_{AB} \text{ and } P_{BA} - jQ_{BA} \quad (8)$$

Because of the non-linearity and complexity of the equations an iterative method such as the Newton-Raphson, developed into computer algorithm, is used in their solution for given convergence criterion. What most of the computer software programs do is to solve similar equation systems as given above.

2. <u>Switching Analysis</u> is done to simulate system behavior when distribution line sections are transfered from one node to another in the same or other feeder. The nodes and sections to be switched are provided to the computer program which automatically performs the operation.

3. <u>Load balancing among phases</u> is achieved by putting loads equally on all phases depending on the nature of the problem. The loss reduction benefit of load balancing can be explained by the following example.

Assume a current reading of 40 amperes in phase A, 130 amperes in phase B and 100 amperes in phase C, each phase having 0.706 ohm resistance and 80 amperes neutral current with 0.234 ohm resistance. The total loss for the unbalanced 3-phase line is equal to

$$0.706\ [40^2 + 130^2 + 100^2]\ + 80^2 \times .234 = 21.6 \text{ kW}$$

Balancing the line current to 90 amperes/phase gives a total loss of 3 x 90^2 x .706 which is equal to 17.16 kW. The loss reduction is 4.46 kW.

4. Capacitor Size and Location Optimization: Capacitors generate reactive power to improved power factor and reduce line currents. In so doing they reduce losses. In loss reduction programs, capacitors of different sizes are placed in different sections in the network. Next, computer programs calculate the losses, and then, the capacitor is located when the desired loss level is achieved. Equally, capacitor size can be given to the program which then locates it where loss is at a minimum.

5. Economic Loading of Conductors and Transformers: Winding losses on a transformer are at a minimum if it is loaded and equally on all phases.

To illustrate this point one can suppose an area is supplied by two substations of 10 MVA rating each with 50 kW winding loss at this load. Loading the first transformer at 12 MVA and the second at 6 MVA results in a total winding loss of:

$$\left[\frac{12\ \text{MVA}}{10\ \text{MVA}}\right]^2 \times 50\ \text{kW} + \left[\frac{6\ \text{MVA}}{10\ \text{MVA}}\right]^2 \times 50\ \text{kW} - 90\ \text{kW}$$

If both transformers are loaded equally at 9 MVA the total loss will be

$$2 \times \left[\frac{9\text{MVA}}{10\text{MVA}}\right]^2 \times 50\ \text{kW} - 81\ \text{kW}.$$

The loss savings is 9 kW.

6. Fault Current Analysis: In fault current analysis line-to-ground (single, double and three phase) and line-to-line currents are calculated depending on the type of the fault by the method of symmetrical components. Similarly the positive, negative and zero sequence fault impedance is calculated.

7. Reconductoring: The current carrying capacity of a transmission line is directly related to the line's area and inversely to its resistance. Thus increasing the conductor's area to an economical level will reduce I^2R losses. Reconductoring involves replacing the conductors of sections with others of larger cross section to improve current carrying capacity.

III. SYSTEM REQUIREMENTS

Most loss calculation programs require a microcomputer that has the following features:

(1) MS DOS 2.0 or higher
(2) Hard disk drive of 10 MB or more capacity
(3) 640 kilobytes of memory
(4) Color monitor and board
(5) a printer

Software packages for the electric utility industry are common in the market. A list of programs for generation, transmission, and distribution (including technical loss analysis) as well as their vendors is extensively covered in Electrical World, November, 1988 issue.

IV. CASE STUDY OF A NETWORK WITH DPA/G 2/

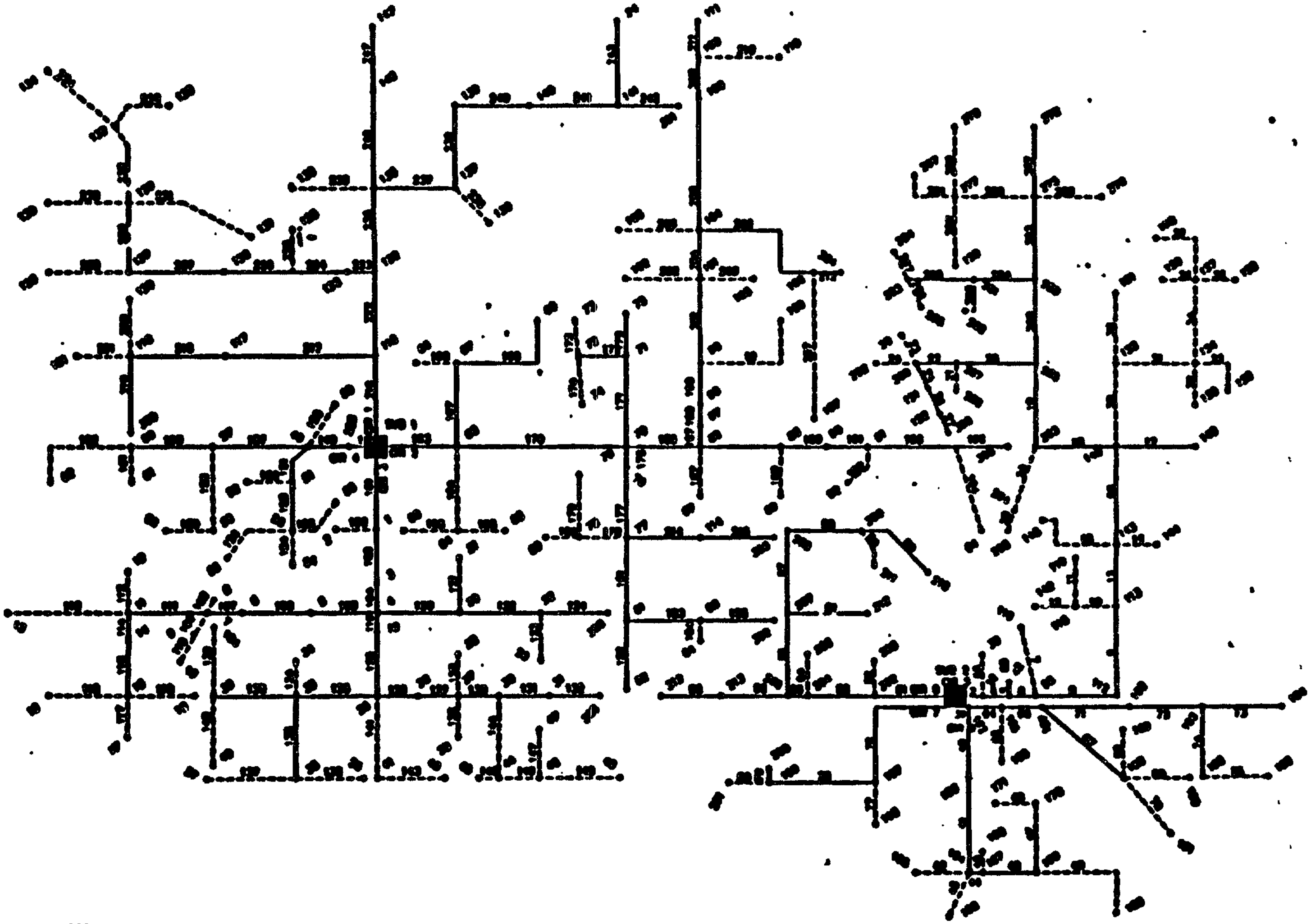
The network (Figure 3) consists of two substations. The procedure for loss analysis is then to:

a. divide the network into separate feeders (circuits), eight in this case;

b. establish database for Control, Feeder, Conductor, Section, Node, Map, Equipment, and Voltage. It is suggested that nodes be established at the following locations:

1. At conductor size changes
2. At changes from overhead to underground
3. Where number of phases change
4. At large power and/or concentrated loads greater than 100 kVA.
5. At the beginning of branch
6. At the end of branch
7. Where future construction will need a node
8. At end of all lines
9. Near all voltage regulating devices and capacitors
10. At sectionalizing devices (fuses on short taps may be skipped).

2/ See Footnote 1. The author selected this software package for demonstration purpose only.



SCOTT & SCOTT CONSULTANTS

FIGURE 3: DISTRIBUTION PRIMARY ANALYSIS EXAMPLE NETWORK

LEGEND

———	3 PHASE PRIMARY LINES
—·—·	2 PHASE PRIMARY LINES
--------	1 PHASE PRIMARY LINES

The following nine programs help in creating the database:

CRECON	--	creates and initializes the control file
EDTCON	--	allows editing of the control file
CREATE	--	creates and initializes the database random access files.
DATAIN	--	inputs the raw data into the database files. Programs utilizing the digitizer to enter data are also available
CHECK	--	locates cross referencing errors, incomplete data and unassigned node and section numbers
BALMAP	--	generates a digital map (for internal storage) of each circuit
PHSCHK	--	checks the phasing information of each section in preparation for by-phase by the analysis program PHSVOL
KWHIN	--	has the option of reading a formatted sequential file for the kWh, number of customers, spot loads, and connected kVA or prompting for terminal entry of kWh and number of customers to be placed in the section file
ALLOC	--	allocates feeder demands to the line sections in proportion to either connected kVA or peak month kWh. Allocation by-phase is an option.

Figure 4 shows the flow chart for establishing the database. Typical data entry forms are given in Annex I. The control file links the DPA analytical programs with the database files.

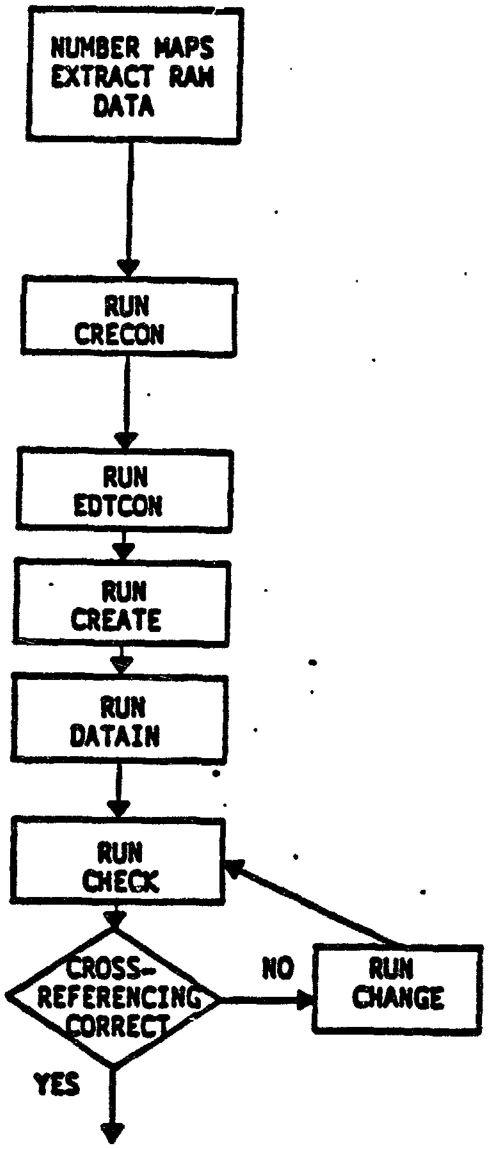
c. run the following analysis and switching programs:

BALVOL -- computes voltage, line loading and losses assuming loads are balanced among the phases. User may change load levels for the entire circuit and/or for selected line sections temporarily or permanently in the section file. Regulators and capacitors may be added or deleted, conductors replaced and phasing changed in the same manner.

PHSVOL -- computes voltage, line loading and losses by phase assuming unbalanced load. User may change load levels for the entire circuit and/or selected line sections temporarily or permanently in the section file. Regulators and capacitors may be added or deleted, conductors replaced and phasing change in the same manner.

CAPLOC -- optimizes the location of capacitor banks based on minimizing losses. Voltage, loading and losses for off-peak conditions are also computed if requested.

FIGURE 4: FLOWCHART FOR ESTABLISHING THE DATABASE



(1) Maps must be numbered and data for the feeder, conductor, section, node and equipment files.

(2) Fill out the DATA INPUT FORMS if data are to be entered manually. If you are digitizing, have the data ready to enter as you digitize.

(3) Run CRECON to initialize the control file.

Run EDTCON to set up database extension, location on disk of database, node and section limit, feeder and map limit, type of terminal being used and any other option that will be different from the preset values.

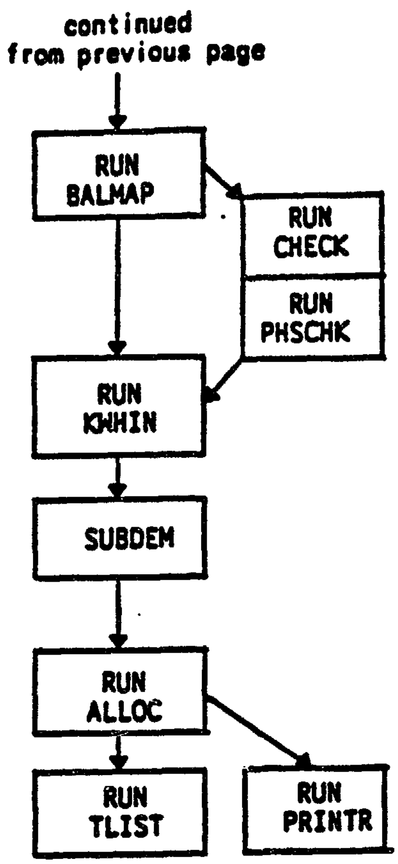
(4) Run CREATE to initialize the database files. INITIALIZE THE DATABASE ONLY ONCE.

(5) Run DATAIN to enter data into the database files. Conductor file and spacing table must be formed before the section data are entered. Capacitors, regulators and primary transformers may be entered at this time. If you are digitizing, refer to the Digitizer Users Manual.

(6) Run CHECK to check for cross-referencing errors and valid records in the section and node files.

(7) Run CHANGE to correct errors in the section and node files. CHANGE may be executed at any time to edit the database.

continued on next page



(8) When cross-referencing is correct, run BALMAP to form the digital map of each circuit. Run CHECK again to be sure all branches are included in maps. Run PHSCHK to check phasing information of each section if PHSVOL is to be executed.

(9) Run KWHIN to enter kWh and customer data via the terminal or formatted file. If the file is read, spot load data and connected kVA may also be entered.

(10) SUBDEM may be run to calculate individual feeder demands if the total substation demand but not the feeder demand is known.

(11) Run ALLOC to allocate feeder demand to sections in proportion to either connected kVA or peak month kWh. Run TLIST or PRINTR at any time to verify the database.

DATABASE IS NOW COMPLETE

FAULT -- uses symmetrical components to compute fault currents for each line section. Output includes minimum and maximum line-to-ground, phase-to-phase and three phase fault levels.

SWITCH -- switches the loads between circuits or between branches of the same circuit.

PLTGEN -- generates a graphical display of selected DPA/G calculated values for plotting with AutoCAD.

d. and analyse the results.

An analysis of the outputs of the five analytical programs is given below. In most cases, only a summary computer printout is provided.

(i) Balanced and Unbalanced Load Analysis

A summary of balanced and unbalanced load analyses calculated by BALVOL and PHSVOL, respectively, is presented in Table 1. The detailed output can be found in Annex II.1 and 2.

Table 1: BALANCED AND UNBALANCED LOAD ANALYSIS

PROGRAM BALVOL (V2.5-C) 22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUMMARY OF ALL FEEDERS IN SYSTEM

	VOLTAGE DROP MAXIMUM			WIRE LOAD MAXIMUM			LOSSES	
	SECT.NO.	VOLTS DROP	LEVEL	SECT.NO.	PCT.CAP.	KVA	KW	KVAR
SUB.1,NORTH-FEEDER	243	16.83	109.17	216	78.68	530.07	357.30	391.55

(a) Balanced

PROGRAM PESVOL (V2.5-C) 22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUMMARY OF ALL FEEDERS PROCESSED

		VOLTAGE DROP MAXIMUM			WIRE LOAD MAXIMUM			LOSSES	
		SECT.NO.	VOLTS DROP	LEVEL	SECT.NO.	PCT.CAP.	KVA	KW	KVAR
SUB.1,WEST-FEEDER	A	162	2.42	123.58	149	41.26	10.13	8.67	5.24
SUB.1,WEST-FEEDER	B	153	.46	125.54	149	26.53	2.71	2.17	1.63
SUB.1,WEST-FEEDER	C	156	4.92	121.08	149	69.44	27.56	23.43	14.50

(b) Unbalanced

Balanced analysis of Feeder 1, Substation 1 gives a maximum voltage drop of 16.83 to a level of 109.17 volts, maximum wire load of 78.68% of its capacity in sections 243 and 216, and total loss of 357.30 kW for the feeder (Table 1a). Similarly, data on Table 1.b show that Feeder 4 (West Feeder), Substation 1 is slightly unbalanced. The load variation among the three phases is less than 1%.

(ii) Capacitor Placement

A base run was obtained without a new capacitor in Feeder 2 (East-feeder), Substation 1. The total power loss obtained is 481.9 kW (see Table 2). Two banks of capacitors (300 and 100 KVAR) were placed by the program in Section 209 and 210 respectively. The total loss dropped to 417.4 kW. When the line was loaded at 30% of its peak load with the new capacitors still in place, no excessive voltage was recorded.

A savings of 53.4 kW resulted from the addition of the 300 KVAR capacitor bank. The 100 KVAR capacitor bank further reduced the losses from 428.5 to 417.4 kW.

Table 2: CAPACITOR PLACEMENT

PROGRAM CAPLOC (V2.5-B)   22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
FEEDER 2 SUB.1,EAST-FEEDER

SECTION NUMBER	LOSSES (KW)	SAVINGS (KW)	CAPACITOR SIZE(KVAR)
BASE	481.9	0.0	0.
209	428.5	53.4	300.
210	417.6	11.1	100.

PROGRAM CAPLOC (V2.5-B)   22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUMMARY OF ALL FEEDERS IN SYSTEM

	VOLTAGE DROP MAXIMUM			WIRE LOAD MAXIMUM		LOSSES		
	SECT.NO.	VOLTS DROP	LEVEL	SECT.NO.	PCT.CAP.	KVA	KW	KVAR
SUB.1,EAST-FEEDER	210	40.57	85.43	208	71.20	725.48	481.93	542.27
SUB.1,EAST-FEEDER	210	31.98	94.02	208	60.32	635.74	417.17	479.72
SUB.1,EAST-FEEDER	207	2.75	123.25	210	29.92	103.35	91.00	48.98

(iii) Fault Analysis.

The fault statistics is given in Annex II.3. Feeder 5, Substation 2 has a line-to-line voltage of 12.47 kV and source impedences (ohm)

$$R_1 = 0.61 \quad , X_1 = 0.4$$
$$R_0 = 0.1 \quad , X_0 = 0.1$$

The computation algorithm assumed a minimum and maximum phase-to-ground resistance of 35 and 0.0 ohms respectively, in calculating the phase-to-ground fault currents. The largest fault current in all phases occurred in source node 32, since it is the nearest to Substation 2.

(iv) Switching Studies.

Program SWITCH joined Section 219 of Feeder 1 to node 60 of Feeder 4 and separated Section 217 from Node 116. Sections 217 to 221 inclusive will now be supplied from Feeder 4 instead of Feeder 1. Table 3 shows the map computed by the program after the switching exercise. Figure 5 is the graphical presentation of the two feeders before and after switching. The program SWITCH therefore allows loss and voltage values to be compared if line sections are transfered from one feeder to another.

Table 3: MAPS OF FEEDER 4 AND 1 AFTER SWITCHING OPERATION

```
PROGRAM SWITCH (V2.5-C)      22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUB.1,WEST-FEEDER                        MAP NUMBER   4

S    1 N  223 S  149 N   49 B   -1 S  150 N   50 E   -2 B   -1 S  151
N   51 B   -1 S  152 N   52 E   -2 S  153 N   53 B   -1 S  156 N   56
E   -2 B   -1 S  154 N   54 E   -2 S  155 N   55 E   -2 S  157 N   57
B   -1 S  160 N   60 B   -1 S  219 N  118 B   -1 S  218 N  117 S  217
N  300 E   -2 B   -1 S  220 N  120 E   -2 S  221 N  121 E   -2 B   -1
S  161 N   61 E   -2 S  162 N   62 E   -2 S  158 N   58 S  159 N   59
*   -3
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PROGRAM SWITCH (V2.5-C)      22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUB.1,NORTH-FEEDER                       MAP NUMBER   1

S  216 N  116 S  222 N  122 B   -1 S  223 N  123 S  224 N  124 B   -1
S  225 N  125 E   -2 S  226 N  126 S  227 N  127 B   -1 S  228 N  128
E   -2 S  229 N  129 B   -1 S  230 N  130 E   -2 B   -1 S  231 N  131
E   -2 S  232 N  132 B   -1 S  233 N  133 E   -2 S  234 N  134 E   -2
S  235 N  135 B   -1 S  236 N  136 E   -2 B   -1 S  237 N  137 B   -1
S  238 N  138 E   -2 S  239 N  139 S  240 N  140 S  241 N  141 B   -1
S  242 N  301 E   -2 S  243 N   24 E   -2 S  246 N  146 S  247 N  147
*   -3
```

FIGURE 5

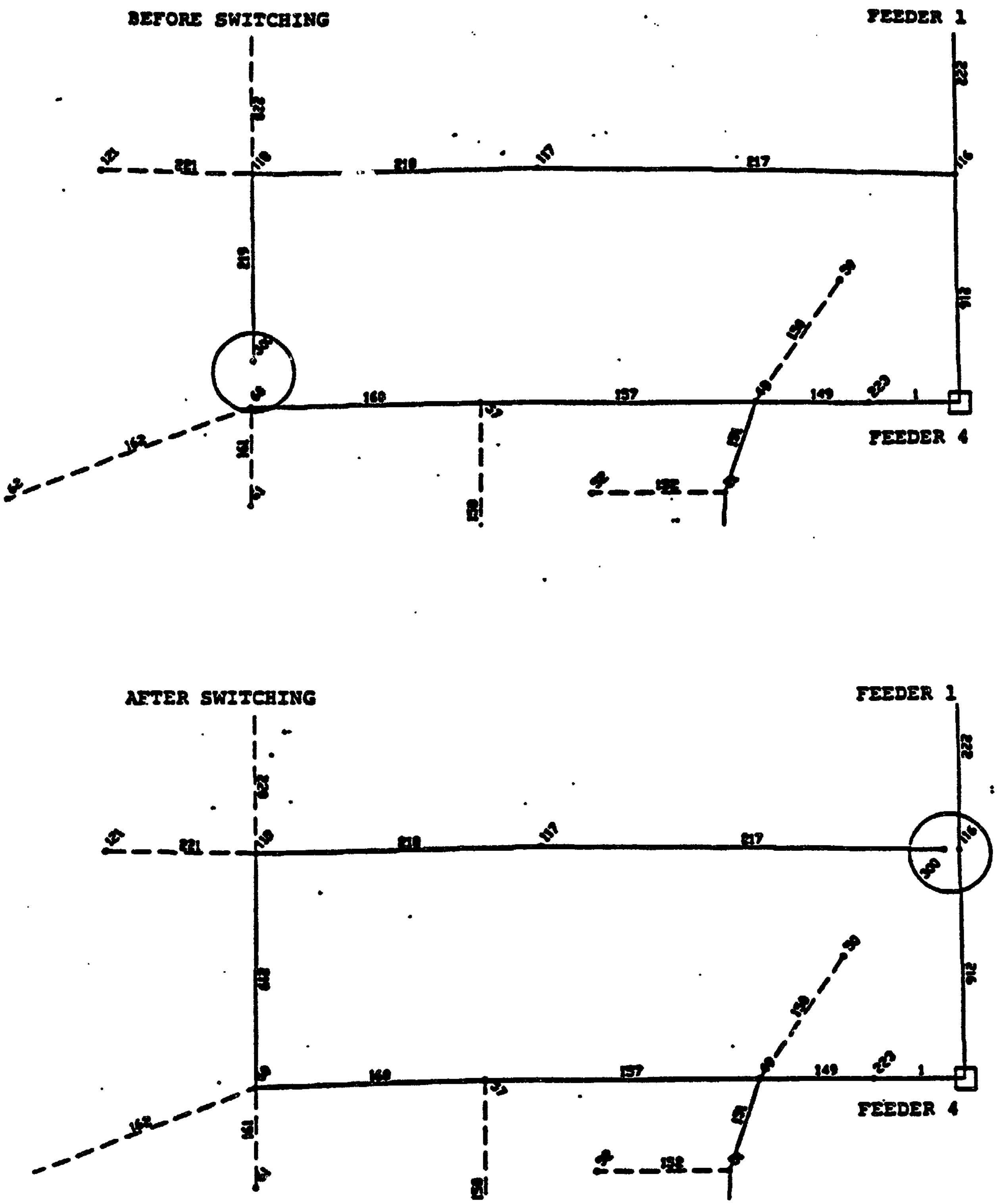

FIGURE 5: SWITCHING STUDY

Source: Scott and Scott Consultants

V. CONCLUSION

The availability of software packages for the electric utility industry that can run on microcomputers has made the calculation of technical losses and implementation of loss reduction programs very feasible. Microcomputers have several advantages over manual, slide rules and calculators in loss calculation. They have high calculation speed; large memory that can store data and perform complex and iterative tasks; and present out in graphical or tabular form.

Life-cycle savings of $15.0 or more for every $1 spent on loss reduction projects are not unusual. Use of microcomputer programs expedites the development of economic loss reduction projects and reduces the overall costs.

FEEDER DATA INPUT FORM

FEEDER NO.	KVLL	BUS VOLT. LEVEL	FEEDER DEMAND (KVA)	PF (%)	FIRST SECTION	SOURCE				L-G FAULT R	FEED. GROWTH RATE
						R1	X1	R0	X0		
FEEDER NAME											
FEEDER NAME											
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FEEDER NAME											

SECTION DATA INPUT FORM

SECTION NO	LENGTH	COND CODE	CONNECTED NODES		CONF CODE	EQUIV SPACING	SPACING CODE	GROWTH RATE	CONNECTED KVA			REGULATOR CODE	NEAREST NODE	REGULATOR SETTING			TRANS CODE	NEAREST NODE	NODE ON HIGH VOLT SIDE	CAPACITOR SIZE			CAPACITOR FLAG
									A	B	C			A	B	C				A	B	C	

PROGRAM BALVOL (V2.5)   22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989

ANNEX II.1

FEEDER 1 SUB.1,NORTH-FEEDER
VOLTAGE = 12.47 KV LINE TO LINE

SECT	END NODE	LGTH K FT	PHASE CONF	COND SIZE	----- LOAD IN SECTION ----- CONN KVA	KW	KVAR	AMPS	CUST	----- LOAD THRU SECTION ----- COND %	KW	KVAR	AMPS	CUST	VOLTAGE 120 BASE SECT DROP	ACCU DROP	LEVEL	-- LOSSES -- KW	KVAR
SUBSTATION TOTALS											4329.	3148.	236.	573.			126.0	357.3	391.6
216	116	5.3	ABC	3/0 AC	37.	49.	34.	3.	2.0	78.7	4305.	3131.	235.	573.	4.2	4.2	121.8	119.5	134.1
217	117	10.6	ABC	4 AC	402.	240.	166.	13.	40.0	28.2	595.	406.	33.	101.	2.8	7.0	119.0	16.6	5.5
218	118	5.3	ABC	4 AC	406.	241.	167.	14.	41.0	18.6	338.	233.	19.	61.	.8	7.8	118.2	2.8	.9
219	300	5.3	ABC	4 AC	41.	51.	35.	3.	3.0	2.1	25.	18.	1.	3.	.1	7.9	118.1	.0	.0
220	120	5.1	A	4 AC	106.	90.	63.	16.	10.0	11.1	45.	31.	8.	10.	.4	8.2	117.8	.2	.1
221	121	3.3	A	4 AC	76.	73.	51.	13.	7.0	9.0	37.	26.	6.	7.	.2	8.1	117.9	.1	.0
222	122	5.3	ABC	3/0 AC	105.	95.	66.	5.	8.0	64.6	3399.	2458.	191.	470.	3.4	7.5	118.5	79.6	89.4
223	123	1.0	ABC	2 AC	235.	157.	109.	9.	23.0	50.8	1536.	1038.	87.	228.	.5	8.1	117.9	7.3	3.7
224	124	4.7	ABC	2 AC	269.	173.	120.	10.	26.0	45.8	1364.	920.	78.	205.	2.2	10.2	115.8	27.0	13.7
225	125	3.6	A	4 AC	214.	145.	100.	25.	22.0	18.2	73.	50.	13.	22.	.5	10.7	115.3	.3	.1
226	126	2.0	ABC	2 AC	286.	182.	126.	11.	28.0	35.5	1014.	683.	59.	157.	.7	10.9	115.1	6.6	3.3
REGULATOR 1 (SETTING 126.00) IN SECTION 227 AT NODE 126											907.	617.			-10.9	.0	126.0	9.8	
227	127	8.8	ABC	4 AC	307.	192.	133.	10.	31.0	34.5	811.	550.	43.	129.	3.1	3.1	122.9	23.9	7.9
228	128	7.9	C	4 AC	245.	160.	111.	26.	26.0	18.9	81.	56.	13.	26.	1.1	4.2	121.8	.8	.2
229	129	5.3	AC	4 AC	131.	103.	72.	9.	13.0	31.2	479.	329.	39.	72.	2.0	5.1	120.9	8.1	2.6
230	130	6.5	C	4 AC	123.	99.	69.	17.	12.0	11.9	50.	34.	8.	12.	.6	5.7	120.3	.2	.1
231	131	6.8	C	4 AC	143.	119.	83.	20.	16.0	14.4	60.	42.	10.	16.	.7	5.8	120.2	.4	.1
232	132	5.0	A	4 AC	103.	87.	60.	15.	11.0	24.0	158.	109.	26.	31.	1.4	6.5	119.5	1.9	.6
233	133	6.0	A	4 AC	133.	103.	71.	17.	14.0	12.5	52.	36.	9.	14.	.6	7.1	118.9	.2	.1
234	134	6.6	A	4 AC	38.	9.	6.	2.	6.0	1.1	5.	3.	1.	6.	.1	6.6	119.4	.0	.0
235	135	4.2	ABC	3/0 AC	238.	158.	110.	9.	23.0	32.4	1578.	1188.	93.	234.	1.3	8.9	117.1	14.8	16.6
236	136	6.1	B	4 AC	124.	100.	69.	17.	12.0	12.4	50.	35.	9.	12.	.6	9.5	116.5	.3	.1
TRANSFORMER 11 IN SECTION 237 AT NODE 135										138.7	1141.	789.	66.		.0	.0	110.8	23.2	105.5
THE VOLTAGE IS 24.900 KVLL																			
237	137	5.4	ABC	2 AC	222.	150.	104.	5.	21.0	19.3	1065.	737.	33.	169.	.5	15.7	110.3	5.5	2.8
238	138	1.8	B	4 AC	24.	33.	23.	3.	2.0	2.2	17.	12.	2.	2.	.0	15.7	110.3	.0	.0
239	139	6.2	ABC	2 AC	262.	171.	119.	5.	24.0	16.2	866.	599.	27.	146.	.5	16.2	109.8	4.2	2.1
240	140	5.3	ABC	2 AC	331.	214.	149.	7.	34.0	13.3	668.	463.	21.	122.	.3	16.5	109.5	2.2	1.1
241	141	5.3	ABC	2 AC	221.	150.	104.	5.	21.0	9.6	484.	336.	15.	88.	.2	16.8	109.2	1.1	.6
242	301	3.0	ABC	4 AC	81.	78.	54.	2.	7.0	1.7	39.	27.	1.	7.	.0	16.8	109.2	.0	.0
243	24	5.3	ABC	2 AC	385.	330.	229.	10.	60.0	5.7	165.	115.	5.	60.	.1	16.8	109.2	.1	.1
THE VOLTAGE IS 12.470 KVLL																			
246	146	7.0	ABC	4 AC	272.	174.	121.	10.	27.0	9.1	133.	92.	8.	30.	.4	9.3	116.7	.6	.2
247	147	4.0	A	4 AC	271.	46.	32.	8.	3.0	5.7	23.	16.	4.	3.	.2	9.5	116.5	.0	.0

END OF FEEDER

2 ITERATION(S) USING .50% AS CONVERGENCE FACTOR

PROGRAM PESVOL (V2.5) 22-JUN-89

ANNEX II.2a

REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989

FEEDER 4 SUB.1.WEST-FEEDER
VOLTAGE = 12.47 KV LINE TO LINE

SECT	END NODE	LGTH K FT	PHASE CONF	COND SIZE	----- LOAD IN SECTION ----- CONN KVA	KW	KVAR	AMPS	CUST	----- LOAD THRU SECTION ----- COND %	KW	KVAR	AMPS	CUST	VOLTAGE 120 BASE SECT DROP	ACCU DROP	LEVEL	-- LOSSES -- KW	KVAR
SUBSTATION TOTALS ON PHASE A											394.	52.	79.	90.				8.7	5.2
			PHASE B								373.	-51.	50.	69.				2.2	1.6
			PHASE C								968.	229.	132.	183.			126.0	23.4	14.5
1	223	2.8	A	3/0 AC	50.	32.	15.	5.	2.0	26.3	378.	45.	77.	90.	.3	.3	125.7	2.4	2.7
			B		50.	16.	7.	2.	1.0	16.6	365.	-55.	49.	69.	.2	.2	125.8	1.0	1.1
			C		10.	49.	22.	7.	3.0	43.9	944.	218.	128.	183.	1.3	1.3	124.7	6.7	7.5
149	49	1.6	A	2 AC	50.	29.	13.	4.	4.0	41.3	545.	83.	73.	88.	.5	.7	125.3	2.8	1.4
			B		165.	110.	49.	16.	15.0	26.6	301.	-30.	40.	68.	.2	.4	125.6	.9	.4
			C		25.	15.	7.	2.	2.0	69.4	906.	249.	126.	180.	1.5	2.8	123.2	8.4	4.3
CAPACITOR IN SECT 149, PHASE A 100 KVAR (109. ADJUSTED)																			
CAPACITOR IN SECT 149, PHASE B 100 KVAR (110. ADJUSTED)																			
CAPACITOR IN SECT 149, PHASE C 100 KVAR (105. ADJUSTED)																			
150	50	6.2	C	4 AC	415.	12.	5.	2.	45.0	1.2	6.	3.	1.	45.	.1	2.9	123.1	.0	.0
151	51	.8	A	4 AC	75.	41.	18.	6.	5.0	11.2	87.	39.	13.	10.	-.1	.6	125.4	.1	.0
			B		115.	82.	37.	12.	10.0	12.6	81.	36.	12.	13.	.1	.4	125.6	.1	.0
			C		25.	8.	4.	1.	1.0	57.8	542.	242.	80.	88.	.7	3.5	122.5	2.7	.9
152	52	2.4	C	4 AC	100.	72.	32.	11.	10.0	7.6	36.	16.	5.	10.	.1	3.6	122.4	.0	.0
153	53	1.0	A	4 AC	70.	66.	30.	10.	5.0	6.9	33.	15.	5.	5.	-.1	.5	125.5	.0	.0
			B		45.	40.	18.	6.	3.0	4.1	20.	9.	3.	3.	.0	.5	125.5	.0	.0
			C		45.	40.	18.	6.	3.0	49.3	443.	199.	66.	77.	.7	4.3	121.7	2.4	.8
156	56	3.5	C	4 AC	310.	229.	103.	34.	42.0	24.6	115.	52.	17.	42.	.7	4.9	121.1	.6	.2
154	54	2.3	C	4 AC	120.	96.	43.	14.	16.0	10.3	48.	21.	7.	16.	.2	4.4	121.6	.1	.0
155	55	2.1	C	4 AC	125.	96.	43.	14.	16.0	10.3	48.	21.	7.	16.	.2	4.4	121.6	.1	.0
157	57	1.7	A	4 AC	195.	98.	44.	14.	14.0	40.6	371.	59.	50.	74.	.7	1.5	124.5	2.2	.7
			B		100.	63.	28.	9.	9.0	12.8	92.	-69.	15.	40.	-.1	.3	125.7	.2	.1
			C		25.	7.	3.	1.	1.0	32.4	329.	43.	45.	45.	.8	3.6	122.4	1.8	.6
160	60	1.9	A	4 AC	175.	166.	74.	24.	26.0	30.7	236.	53.	32.	60.	.7	2.1	123.9	1.1	.4
			B		15.	6.	3.	1.	1.0	9.7	57.	-29.	8.	31.	-.1	.2	125.8	.1	.0
			C		90.	64.	29.	10.	10.0	9.6	32.	-38.	7.	10.	.0	3.7	122.3	.0	.0
CAPACITOR IN SECT 160, PHASE A 100 KVAR (107. ADJUSTED)																			
CAPACITOR IN SECT 160, PHASE B 100 KVAR (110. ADJUSTED)																			
CAPACITOR IN SECT 160, PHASE C 100 KVAR (104. ADJUSTED)																			
161	61	2.2	B	4 AC	320.	53.	24.	8.	30.0	5.5	27.	12.	4.	30.	.1	.3	125.7	.0	.0
162	62	2.3	A	4 AC	325.	152.	68.	22.	34.0	16.1	76.	34.	11.	34.	.3	2.4	123.6	.2	.1
158	58	1.4	C	4 AC	165.	145.	65.	22.	20.0	27.7	187.	84.	28.	34.	.4	4.1	121.9	.6	.2
159	59	1.9	C	4 AC	115.	114.	51.	17.	14.0	12.2	57.	26.	9.	14.	.2	4.3	121.7	.1	.0

END OF FEEDER

2 ITERATION(S) USING .50% AS CONVERGENCE FACTOR

ANNEX II.2b

PROGRAM FESVOL (V2.5-C) 22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
SUB.1,WEST-FEEDER
FEEDER NUMBER 4

KILOWATT,KILOVAR AND CURRENT FLOW
BY
PHASES AND NEUTRAL

SECT	KILOWATTS			KILOVARS			AMPERES			
NO.	A	B	C	A	B	C	A	B	C	N
SUBSTATION TOTALS	593.9	372.9	968.4	52.3	-51.4	229.2	78.9	49.8	131.6	76.3
1	577.7	364.8	944.1	45.0	-55.0	218.3	76.7	48.8	128.2	74.3
149	544.5	300.7	905.9	83.0	-29.6	249.3	73.0	40.0	125.6	77.9
150	.0	.0	5.9	.0	.0	2.6	.0	.0	.9	.9
151	86.7	80.7	541.6	38.9	36.2	242.3	12.6	11.7	80.3	68.0
152	.0	.0	35.9	.0	.0	16.1	.0	.0	5.4	5.4
153	33.1	19.8	443.2	14.8	8.9	198.5	4.8	2.9	66.1	62.2
156	.0	.0	115.1	.0	.0	51.6	.0	.0	17.3	17.3
154	.0	.0	47.9	.0	.0	21.5	.0	.0	7.2	7.2
155	.0	.0	47.9	.0	.0	21.5	.0	.0	7.2	7.2
157	370.7	91.6	329.1	59.4	-68.7	43.4	49.9	15.2	44.9	38.8
160	236.4	56.6	32.0	52.7	-29.5	-37.6	32.4	8.5	6.7	28.6
161	.0	26.7	.0	.0	12.0	.0	.0	3.9	.0	3.9
162	76.3	.0	.0	34.2	.0	.0	11.2	.0	.0	11.2
158	.0	.0	187.4	.0	.0	84.0	.0	.0	28.0	28.0
159	.0	.0	57.2	.0	.0	25.6	.0	.0	8.6	8.6

ANNEX II.3a

PROGRAM FAULT (V2.3-B)   22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
FEEDER 5, SUB.2,NE.FEEDER
SUBSTATION VOLTAGE 12.47 KV LINE TO LINE
SOURCE IMPEDANCES (OHMS) R1 = .610 X1 = .400   * ASSUMES 35.0 OHMS
R0 = .100 X0 = .100   ** ASSUMES 0.0 OHMS

NODE	NODE LOCATION	WIRE SIZE	K/FT FROM SUB	-------CUMULATIVE------- POSITIVE SEQ. R (OHMS)	POSITIVE SEQ. X (OHMS)	ZERO SEQ. R (OHMS)	ZERO SEQ. X (OHMS)	PH-TO-GR MIN* (AMPS)	PH-TO-GR MAX** (AMPS)	PH-TO-PH (AMPS)	3-PH (AMPS)
SOURCE								203.	13519.	8548.	9870.
32		397 AC	1.056	.662	.526	.209	.690	203.	9309.	7374.	8515.
39		4 AC	3.696	1.947	.940	1.637	2.295	195.	3117.		
42		397 AC	5.016	.856	1.000	.618	2.901	201.	3981.	4738.	5470.
85		4 AC	7.656	2.141	1.414	2.046	4.506	194.	2230.		
95		397 AC	7.656	.985	1.316	.890	4.375	200.	2854.	3794.	4381.
96		4 AC	11.616	2.912	1.936	3.032	6.783	189.	1559.		
112		397 AC	12.936	1.244	1.947	1.435	7.323	197.	1818.	2699.	3116.
113		3/0 AC	18.216	1.967	2.758	2.444	10.452	192.	1256.	1840.	2125.
115		4 AC	20.064	2.866	3.048	3.444	11.576	187.	1085.		
119		4 AC	22.176	3.894	3.379	4.586	12.860	181.	931.		
142		4 AC	22.704	4.151	3.462	4.872	13.181	180.	899.		
143		3/0 AC	21.648	2.437	3.286	3.100	12.485	189.	1046.	1524.	1760.
144		4 AC	25.344	4.235	3.865	5.099	14.733	179.	823.		
145		4 AC	29.568	6.291	4.527	7.384	17.301	169.	653.		
148		3/0 AC	29.304	3.485	4.462	4.563	17.021	181.	761.	1101.	1272.
149		4 AC	33.528	5.540	5.142	6.848	19.555	171.	620.	825.	952.
293		1/0 AC	33.264	4.325	5.097	5.617	19.394	176.	638.	933.	1077.
286		1/0 AC	38.544	5.444	5.944	7.024	22.557	169.	556.	774.	893.
280		1/0 AC	43.824	6.564	6.790	8.430	25.720	163.	482.	660.	762.
*** SOURCE TERMINALS				6.564	6.790	8.430	25.720	163.	482.	660.	762.
*** TRANSFORMER 10 IN SECTION 293 AT NODE 280											
*** THE VOLTAGE IS 24.900 KVLL											
*** LOAD TERMINALS				36.093	88.274	43.530	163.754	106.	120.	131.	151.
275		1/0 AC	49.104	37.213	89.121	44.937	166.917	105.	118.	129.	149.
272		1/0 AC	54.384	38.333	89.967	46.343	170.080	103.	116.	127.	147.
276		4 AC	53.064	39.141	89.741	47.078	169.325	103.	116.		
277		4 AC	54.384	39.783	89.948	47.792	170.128	103.	116.		
278		4 AC	59.136	42.096	90.693	50.363	173.017	101.	114.		
279		4 AC	59.928	42.481	90.817	50.791	173.499	101.	113.		
150		4 AC	58.872	41.967	90.651	50.220	172.857	101.	114.		
*** THE VOLTAGE IS 12.470 KVLL											
281		4 AC	49.134	9.134	7.639	11.286	28.887	153.	406.	524.	605.
282		4 AC	53.856	11.447	8.384	13.856	31.776	144.	355.		
283		4 AC	53.592	11.318	8.361	13.713	31.578	145.	357.	443.	512.
284		4 AC	55.968	12.475	8.734	14.998	33.023	141.	335.		
285		4 AC	55.440	12.218	8.651	14.713	32.702	142.	340.		

ANNEX II.3b

PROGRAM FAULT (V2.5-B) 22-JUN-89
REGIONAL SEMINAR ON ELECTRIC LOSS REDUCTION JULY 3-7,1989
FEEDER 5, SUB.2,NE.FEEDER
SUBSTATION VOLTAGE 12.47 KV LINE TO LINE
SOURCE IMPEDANCES (OHMS) R1 = .610 X1 = .400 * ASSUMES 35.0 OHMS
R0 = .100 X0 = .100 ** ASSUMES 0.0 OHMS

NODE	NODE LOCATION	WIRE SIZE	K/FT FROM SUB	POSITIVE SEQ. R (OHMS)	POSITIVE SEQ. X (OHMS)	ZERO SEQ. R (OHMS)	ZERO SEQ. X (OHMS)	PH-TO-GR MIN* (AMPS)	PH-TO-GR MAX** (AMPS)	PH-TO-PH (AMPS)	3-PH (AMPS)
			-------------CUMULATIVE-------------								
287		4 AC	43.824	8.014	6.793	9.879	25.723	158.	459.	593.	685.
288		4 AC	46.464	9.299	7.207	11.307	27.329	153.	421.		
289		4 AC	46.200	9.171	7.175	11.165	27.148	153.	426.	535.	618.
291		4 AC	48.312	10.199	7.506	12.307	28.[illegible]33	150.	397.		
292		4 AC	50.424	11.226	7.837	13.449	29.717	146.	373.		
151		4 AC	48.952	10.510	7.618	12.653	28.799	148.	390.	480.	555.
152		4 AC	49.952	10.997	7.779	13.194	29.393	147.	378.	463.	534.
309		4 AC	50.952	11.483	7.940	13.735	29.998	145.	368.	447.	516.
294		4 AC	38.808	7.023	5.966	8.616	22.765	163.	521.		
295		4 AC	40.656	7.922	6.255	9.616	23.889	159.	486.		
153		4 AC	34.584	6.034	5.290	7.419	20.232	168.	592.		
154		4 AC	39.864	8.624	6.117	10.275	23.443	157.	479.		
155		4 AC	41.976	9.652	6.448	11.417	24.727	153.	445.		
156		4 AC	43.560	10.423	6.696	12.274	25.690	150.	422.		
157		4 AC	45.144	11.194	6.944	13.131	26.653	148.	401.		
158		4 AC	47.256	12.222	7.275	14.273	27.938	144.	376.		
159		4 AC	46.992	12.093	7.234	14.130	27.777	145.	379.		
160		4 AC	48.576	12.864	7.482	14.987	28.740	142.	362.		
161		4 AC	39.336	8.367	6.034	9.989	23.122	158.	489.		

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ST. VINCENT ELECTRICITY SERVICES LTD. - CASE STUDY

By

Mr. Lennox Morris

ST. VINCENT AND THE GRENADINES - GEOGRAPHY

1. St. Vincent is the second smallest Windward Island, with an area of only 133 square miles. It is situated approximatley 100 miles north of Grenada, 21 miles south of St. Lucia and 100 miles west of Barbados.

2. There are seven major Grenadines Islands governed by St. Vincent. These islands extend in a chain between St. Vincent and Grenada and include Bequia, Union Island and Canouan; hence St. Vincent and the Grenadines. The total area of the Grenadines is approximatley 35 square miles.

3. St. Vincent is volcanic in origin and is therefore mountainous. There is a range of mountains stretching over almost the entire length of the island from La Soufriere in the North to Mt. St. Andrews in the south. This mountainous terrain inhibits the development of inland St. Vincent. Industrial, commercial and housing development is thus confined largely to the coastal areas and, more so, to the southern coastal areas of the island.

4. The total population of St. Vincent and the Grenadines is approximately 120,000.

VINLEC'S SCOPE OF OPERATION

5. The public electricity utility in St. Vincent and the Grenadines is the St. Vincent Electricity Services Limited (VINLEC). It is a Government- owned company which has the monopoly on the supply of electricity on St. Vincent and Bequia. Under contract with the Government, VINLEC also operates the electric system in Union Island. VINLEC, on behalf of the Government, is now doing a feasibility study on the electrification of Canouan.

GROWTH OF VINLEC SYSTEM

Generation

6. The first power station in St. Vincent was opened in 1930 in Kingstown to supply the town and its environs from two 40 kW generating sets. The station was operated and owned by the Crown Colony Government with assistance from the appropriate colonial agencies (Colonial Development and Welfare, Crown Agents).

7. The expansion of the system was slow at first, mainly due to the low level of industrial activity. By 1953 the supply extended from Ratho Mill on the Windward side to Camden Park on the Leeward side of the island. The

installed capacity at the power station had increased to only 368 kW but apparently the plant was running at 10% overload during the evening peak period.

8. However, the need for a cheaper source of electricity had already been recognised. Around 1949 work was started on the South Rivers hydroelectric scheme by CD&W on behalf of the St. Vincent Government. The Colonial Development Corporation was invited to complete the project and was given the mandate to own and operate the public electricity supply as a monolopy under legislation drafted for that purpose. South Rivers Hydro station was commissioned in 1953 with two 275 kW impulse turbines. Another turbine of 320 kW capacity was added the following year.

9. As demand increased steadily a new hydro electric scheme was planned for the Richmond River. This project was started in 1959 and completed in 1961. The station provided an installed capacity of 1100 kW and came on stream in time to relieve the then strictly enforced load shedding to industrial consumers during the evening peak.

10. The two hydro stations are the run-of-river type (South Rivers has a small balancing tank). Their output is therefore greatly reduced during the dry season (to about 40%). Therefore, to meet increasing demand and provide sufficient firm capacity during dry season, a second diesel station was built at Cane Hall. Commissioned in 1971, this station provided an installed capacity of 3646 kW. Meanwhile the Kingstown station had expanded to provide 2136 kW.

11. The rate of increase in demand slowed considerably during the years 1972 to 1977. This was due in part (1974 - 1977) to the world energy crisis.

12. The St. Vincent Government began negotiations for participation in the Company about the same time that this slow-down began. This participation was obtained in 1973 when St. Vincent Electricity Services Limited (VINLEC) became a limited liability company with 49% Government participation.

13. 1974 saw steep increases in the prices of oil, spare parts, equipment and services and in spite of the fuel surcharge levied to recover the additional expenditure resulting from increases in fuel oil prices over the October 1973 level, the Company faced a substantial deficit in its operations by year end. From this point onwards to the early 1980's funds remained in short supply.

14. The coming on stream of the flour mill and the beginning of development of the Camden Park Industrial Estate in 1978 caused a substantial jump in demand. This growth in peak demand came to a standstill in 1980 when load-shedding became a must, due to prolonged dry spells and machine maintenance problems.

15. Commonwealth Development Corporation (CDC) in its quest for funds to increase diesel capacity was not very successful. They therefore had to be contented ith the purchase of three diesel standby sets of 600 kW each in 1983. These sets were installed at Cane Hall and came on stream in January 1984.

16. The Government of St. Vincent and the Grenadines became the sole owner of VINLEC in June 1985. In that same year another diesel unit of 3200 kW capacity was added at Cane Hall and construction of the Cumberland Hydroelectric scheme was started.

17. The Cumberland hydro scheme comprises three power stations in a cascade arrangement on the Cumberland River. The first station commissioned in June 1987, provided one unit of 1464kW rated output. The second station, commissioned in October 1987, provided 1280kW, and the third station, providing 950kW, came on stream in March 1988.

Transmission and Distribution

18. The Company's Transmission and Distribution system had not grown at the same rate and with the same level of planning as generation.

19. In 1951 CDC was required by law to build an 11kV overhead line to link the South Rivers and the Kingstown power stations and to build spur lines into Georgetown, Mesopotamia and Camden Park. This comprised some 37.5 km of lines mainly on the Windward side of the Island, only 6.4km from Kingstown to Camden Park being on the Leeward side.

20. In 1961 when Richmond hydro plant came on stream another 21km of 11kV lines were added to the system to link Richmond on the North Leeward side of the island, to Kingstown.

21. These two 11kV lines linking the two hydro stations to Kingstown, formed the backbone of the primary distribution system in St. Vincent. It is worthy of note that some areas of these two lines remained untouched in terms of maintenance or modification until 1986.

22. After the Cane Hall Power Station was built another section of 11kV lines approximately 6.5 km long was built to link the Cane Hall and Kingstown plant. The rest of the primary distribution followed load growth. In some cases 6.3 kV single earth return lines were built to supply electricity to relatively small loads in remote areas.

23. In 1987 a 33kV line was built to link Cumberland Hydro Station to Cane Hall Station and to a distribution substation at Camden Park.

24. To date, the transmission and primary distribution system comprises 30km of 33 kV lines, 130km of 11kV three phase, 30km of 11kV two phase and 8km of 6.3kV single phase lines. Secondary distribution is done at 400V three phase or 230V single phase 50 Hz. It is difficult to assess the length of LV circuits since no LV mapping was done until very recent times.

FACTORS CONTRIBUTING TO HIGH LEVEL OF LOSSES

Organisation and Staffing

25. In the earlier life of the Company under CDC's management, the company was run strictly as a profit-making concern. The local management comprised one chief executive below whom were only people at the craftsman's level. The chief concerns of the Company seem to have been to keep the machines running and to collect the Company's revenue. No organised Transmission and Distribution (T&D) staff was retained by the Company until about 1960.

Transmission and Distribution

26. In 1960 during the building of the Richmond to Kingstown 11kV line, two T&D crews were organised under a T & D Superintendent. The qualification for entry into one of these crews was experience as a sailor, the reasoning being that if one could climb a mast he would also be able to climb a pole. No recognition was given to the fact that a little technical knowledge would at least be helpful. The trend was therefore set, and until the early 1980's a linesman was someone who could climb and work on a pole. T&D operated two 12-man line crews until the early 1980's.

27. The Company's distribution policy seems to have been to get power to the consumer at the cheapest possible cost. This is illustrated by the Richmond to Kingstown 11kV line. The voltage at Richmond had to be maintained at 12.2kV in order to obtain 11kV at the Kingstown busbars. This is a result of a decision to economise on conductor size. Kingstown and its environs are the main load centres.

28. The primary distribution system was expanded without any engineering planning and without any standards. Several single 6.3kV ground return lines were constructed to take supply to remote areas. As the load in these areas grew these 6.3kV lines were further extended, until in 1983 there were some 25.5 km of such lines. One would be amazed to know that the conductor used for most of these 6.3kV lines was 3/8" guy steel.

29. LV distribution circuits fed from fairly large transformers were extended span-by-span to keep in step with growing housing development. This led to situations where consumers at the end of the LV line had severe low voltage problems while those close to the transformer suffered from over-voltage. Needless to say no one paid any attention to conductor size or type. In 1983 some of these LV circuits were found to be over a mile long.

CDC Attitude to Maintenance

30. After 1973 when Government bought into the Company it was generally known that Government would eventually move towards total take-over. By 1974 the Company was in deficit. CDC therefore had nothing to gain by pumping money into VINLEC's operations. Their level of maintenance dropped to the bearest minimum; that being whatever it took to hold the system together. Lack of spares and proper materials led to the further deterioration of the T&D system. Twisted connections, bridged HV fuses and installation of rebuilt American transformers were some of the results.

Hurricane Allen 1980

31. In 1980 St. Vincent was struck by Hurricane Allen and extensive damage was suffered by VINLEC's T&D system. The T&D staff immediatley set about the task of repairing the system. With material already in short supply, every bit of available scrap material was used in the effort to get the system operating again. Although this was necessary at the time it of course caused losses to increase even further.

Fire of 1980

32. So far, attention has been focused on factors affecting technical losses, but non-technical losses were also high. The fire of 1980 which destroyed VINLEC's commercial office contributed tremendously to the high level of non-technical losses. All consumer and meter records were destroyed.

33. Until 1983 there were still consumers connected to the system whose records were not re-established since the fire, and were therefore not billed. Some people seized the opportunity to become illegally connected to the system. Theft of service became more widespread since people were aware that no consumption pattern could be established.

34. Up to 1982 billing was done by hand and by the time the billing system was computerised that same year bills were five months in arrears. Although the computer system had the capability of identifying changes in consumption pattern, active monitoring of consumer accounts did not begin until 1984.

Metering Inaccuracy

35. A limited metering survey by VINLEC in 1981 indicated that losses due to metering inaccuracy was high enough to cause concern. However, no meter inspection programme was implemented until 1982. Before this time, once a meter was installed, it was not replaced or tested unless severely damaged or the customer complained about being overbilled. It is small wonder, then, that some old five and ten amp meters that were long ago damaged by constant overload are only now being removed from the system. Several meters exposed to weather or clogged with dust due to cracked or loose glass would also have contributed to los~es.

POWER LOSS STUDY

Background

36. By 1979-80 VINLEC knew that a serious power loss problem existed, but with load shedding a common practice by then, the immediate concern was to secure funds to increase the diesel generating capacity. CDC in 1980 approached the Caribbean Development Bank (CDB) to finance a new diesel generating set.

37. However, CDB insisted that a study to determine the least cost proposal for generation be conducted. The study, conducted in 1981, had such terms of reference that it was able to investigate other aspects of VINLEC operations besides generation. This study identified losses as an area that required greater investigation.

38. In 1983 the Caribbean Community (CARICOM) commissioned a power loss reduction study for St. Vincent and the Grenadines, using USAID funds. The objective of the study was to identify the sources of losses in the distribution system and to make recommendations for reducing them to the optimum level. The study was addressed both to the effect of losses on the economy and to the financial implications to VINLEC of the resulting loss reduction programme.

39. The study was conducted by Adair & Brady International Inc., Consulting Engineers operating out of Florida, USA.

Findings

40. In 1982 the power system served 11,384 consumers. The peak demand of 5.5 MW occurred in December, and the total energy sold for the year was 21,778 MWh. The energy generated was 29,033 MWh, 11,027 MWh of which was generated by hydro plants and 18,606 MWh by diesel plant, with company's own use amounting to 652 MWh, distribution losses amounting to 6,603 MWh or 23.3% of net generation. The year-to-date figure up to March 1983 put losses at 26.3%.

41. It should be noted here that the actual percentage loss may have been higher than that reported, since it was later discovered that some of the stations kWh meters were slow.

42. The approximate distribution of losses on the St. Vincent system at the end of 1982 (23.3% of net generation) as reported by Adair & Brady was as follows:

a) Technical losses in:

Step-up transformers	2.0%
H.V. lines	1.6%
Distribution transformers	2.4%
L.V. services	6.5%
TOTAL	12.5%

(b) Non-technical losses total 10.8%, caused, in descending order of importance, by:

Theft of service
Inadequate billing
Meter inaccuracy

43. The exact division of the losses among the non technical categories was not known but the impact of the first two items was clearly illustrated by Adair & Brady's findings during the field work associated with the study.

44. Nine consumers who were either suspected of stealing electricity or were not being billed were identified. Together they accounted for 3.1% of the system losses and represented an annual loss of revenue to the utility of over EC$400,000 per year. In comparison, the net income for 1982 was just over EC $800,000.

Loss Reduction Target

45. A target of 7% losses by 1988 was set by Adair & Brady, the mix being 6.5% technical and 0.5% non-technical. Adair & Brady estimated that the planned reduction in non-technical losses would have caused a drop in peak demand of 290kW by 1986 and 450kW by 1988. The planned reduction in non-technical losses was expected to effect a net saving in 1986 of EC$976,529 and annual savings of EC$3,199,154 by 1990.

46. Their proposed loss reduction programme required an investment of approximately EC$13.2m between 1985 and 1988; it was expected that of this amount approximately EC$11.9m would be recovered by 1990. It was also estimated that savings to the consumer would be approximately EC$0.19 per kWh by 1990.

Recommendations

47. The main actions recommended to achieve the proposed loss reduction targets were as follows:

For reduction of technical losses

1. Install 300 kVAR banks of capacitors as follows:
   7 in 1985; 3 in 1986; 1 in 1987; 1 in 1988

2. Install capacitors in future to maintain power factor established in 1988.

3. Break L.V. distribution into smaller sections by extending the H.V. distribution and using more transformers.

4. Apply new standards which incorporate larger conductor sizes and define maximum run lengths for L.V. distribution.

For reduction of non-technical losses

1. Move meter installations of all industrial and large commercial consumers to the exterior of their buildings, change meters to socket mounted kVA demand types.

2. Move some commercial and domestic meters to the outside of building each year, replace meters with socket-mounted meters.

3. Institute a policy requiring all new meter installation to be socket-mounted and conveniently located outside of buildings.
4. Institute and enforce a new meter sealing policy.

5. Survey consumers to re-establish billing data base.

For Improvement of Productivity

1. Construct new distribution centre, including offices, stores, workshops and adequate parking space for company vehicles.

2. Restructure the line crews to form a specialist pole-planting crew and separate three-man line construction crews.

3. Train line crews in the use of modern techniques; for example, hot line connection of transformers and fuses.

4. Obtain and use correct fittings and tools for alumimium to copper connections.

PROJECT IMPLEMENTATION

Factors Affecting Project Schedule

Final Report

48. At the very outset a number of factors contributed to delays in the implementation of a power loss reduction programme in St. Vincent. The first delay came in the delivery of Adair & Brady's final report to VINLEC; although the study was completed in April 1983, the final report was not received by VINLEC until early 1984, nearly one year later.

Funding

49. A power loss reduction project was now defined for VINLEC. About this time, however, Government, on behalf of VINLEC, was in the process of negotiating funding for the Cumberland Hydroelectric Development project. A substantial amount of funds were therefore expected to be put into VINLEC by several loan and donor agencies. It was decided that these agencies should combine and make one input into VINLEC to cover the projects then pursued by the Company; namely Cumberland Hydro, Power Loss Reduction, Transmission and Distribution Extension and Transformer Improvement.

50. These extended negotiations contributed to some delays in securing funding for the loss reduction programme.

51. The Caribbean Development Bank (CDB) decided to fund the project, and the projects engineer was recruited and the power consultant selected in the latter half of 1985. It was expected that this would have been done in mid-1984 and that 1985 would have seen the project well under way. The project was therefore about a year behind schedule by that time.

Procurement and Standards

52. The project engineer's first task on arrival in St. Vincent would have included obtaining and evaluating bids for supply of materials and planning a programme for the execution of the loss reduction work. At this time, however, material specifications and construction standards were not available. Standards and material and equipment specifications were discussed with the consultant and having come to agreement on what was required, procurement began.

53. It must be noted here that the final copy of the construction standards manual was not delivered to VINLEC until 1988. The requirements for the majority of these Standards were obtained from VINLEC technical staff and introduced with only minor modifications. Even after the delivery of the final copy several Standards had to be redrawn by VINLEC.

54. The first batch of meters ordered with project funds did not arrive in St. Vincent until late 1986. The line hardware ordered for the start of construction did not arrive until 1987. The line trucks, so essential to high productivity on the project, did not arrive until mid 1987, and capacitors, expected to have a significant impact on the reduction of HV losses, did not arrive until 1989. (The proposed locations and voltage setting for switched banks were delivered about the same time.)

55. The lack of proper storage facilities in VINLEC presented another problem in the availability of materials during the first half of the project. Materials had to be ordered in small quantities because of inadequate storage space. As speed of construction increased the materials ordered were quickly used up and ever so often stocks of essential items were exhausted. In some instances the materials ordered were not entirely suitable. For example, the first batch of consumer meter bases ordered had non-tinned alumimum terminals. Use of copper conductor with these meter bases have resulted in serious corrosion problems.

Initial Construction Activities

56. Before the arrival of any materials ordered under the loss reduction project, the project engineer decided to start reconstruction of the distribution system in the Murray's Village area just outside Kingstown proper, using VINLEC materials and the T&D Construction Crew. It was the first time that a scheme of this type was planned within VINLEC. The planning included mapping and voltage drop calculations.

57. The construction work in this area went very slowly, due to the inefficient work methods of the VINLEC crew and the number of times this crew had to be diverted from the project to do breakdown maintenance work. It became obvious during that time that there existed a need for skilled linesmen, more efficient crews and petty contractors. The Murray's Village scheme took over one year to build. A scheme of comparative size today will require four months at the most to build.

Training

58. The staffing needs of the project required that the Company's staff be increased considerably. The staff required included linesmen, metering staff and meter inspectors. Workers skilled in these areas are not readily available in St. Vincent (probabably the case in most Caribbean countries). Workers, therefore, had to be recruited and trained. Most of the trainees were high school graduates and graduates from the two-year electricity or electronics programme of the St. Vincent Technical College.

59. The first batch of 12 trainee linesmen were recruited in April 1986; a second batch of 8 in January 1987.

60. Seven metering staff were recruited in October and November 1986, after the arrival of meters, and training of these recruits began in November 1986.

61. All training was conducted in St. Vincent. This was the result of a decision taken by VINLEC to utilize, as far as possible, its own resources; in any case, VINLEC considered that the overseas training available was unsuitable.

62. In November 1986 a foreign metering instructor was employed for two weeks to train seven trainees and existing metering staff. In November 1987 a foreign linesman trainer was employed to conduct training in modern construction techniques; his services were further engaged in October 1988. The latter found

it difficult to work with locals because he found them slow to respond at times, and they in turn often found his language offensive.

63. On-the-job training of linesmen was done during construction work, so that the speed of construction in the initial stages was not as great as would have been hoped. Delays in the arrival of training equipment and materials also contributed to a longer training period. For example, the line trucks were delivered late and training on their use and maintenance could only have been carried out after their arrival.

Redistribution of Funds

64. The costing of the individual project components proved to be somewhat inaccurate in some areas. For example, in the area of L.V. distribution reconfiguration, the extent of the H.V. rebuilding required was not fully appreciated. Furthermore, in the rebuilt areas the H.V. system had to be extended, because of social and political pressures, to include new consumers. In this area, too, the extent to which petty contractors had to be used was not anticipated.

65. Funds therefore had to be shifted between some project components to take care of some of these dificiencies. The process of authorization of the shifting of these funds resulted in further project delays.

PROGRESS AND RESULTS

66. When Adair & Brady visited St. Vincent in 1983 they estimated VINLEC's power losses at 23.3% of net generation. They suggested a target of 7% for a loss reduction project. During the development of the project the target level for reduction of system losses was set initially at 10%. This target has not yet been achieved, but the year-to-date calculation up to the end of May 1989 put system losses at 14.5% of net generation. In fact, the losses over the last six months have been just about the 12% level.

67. Peak demand loss reduction together with the resultant lowering of peak demand is difficult to evaluate. This is due to the direct relationship between load demand and improved voltage levels resulting from loss reduction activities. It is estimated that improved voltage has increased load demand in the order of 2%. In fact, VINLEC has recorded increases of up to 30% in some customers' consumption due solely to voltage improvement.

68. To date, some EC$16.33 million has been spent on the power loss project (see Appendix 13). Of this cost, just over EC$6.0m has been indirect cost; for example, cost for T&D Centre, vehicles, training, etc. This leaves direct cost at EC$10.24m.

69. Savings due to loss reduction to date total approximately EC$1.4m. This means that of the EC$16.33m, only EC$14.93m has to be recovered. At present loss levels (14.5%) and present production costs, this gives a pay-back period of about 12 years for total expenditure and 7 years for direct costs.

TECHNICAL LOSSES

High Voltage Lines

70. In 1982 losses in HV lines accounted for 1.79% of net generation. By the end of 1988 HV losses had been reduced to 1.66%, due mainly to the new 33kV line from Cumberland and reconducting of some 11kV lines.

71. To date, some 32km of three phase and 19km of two phase 11kV lines have been rebuilt. As an added benefit to loss reduction, the 11kV rebuild gives VINLEC greater flexibility in system configuration. New ring circuits allow smaller areas to be isolated during planned maintenance shutdowns.

72. The feeders identified in the Adair & Brady report as having the most HV losses have been given priority in the rebuild programme. These are Sion Hill, Richmond and Belmont, in that order.

Capacitors

73. C I Power's analysis of capacitor requirements differed tremendously from Adair & Brady's recommendations. They estimated that 1050 kVAR of switched capacitor and 1200 kVAR of unswitched capacitor were required to provide the required power factor correction to the system.

74. As mentioned before, these capacitors, along with installation details, have been received by VINLEC within the past four months. Towards the end of May three banks totalling 750 kVAR of unswitched capacitors have been installed. Installation of the rest require pole changes at some locations, and the establishment of exact voltage levels on feeders once all static banks have been installed. The effect of the installed capacitors on the system is not yet known. However, it is estimated that the installation of all capacitors would result in a loss reduction of 0.3% of net generation and 2% of the system peak demand due to voltage improvement.

Power Transformers

75. The Cumberland project added five new power transformers to the system. This caused an increase in power transformer losses of approximately 0.15%. Not much can be done about reducing power transformer losses, although such losses will decline as the system peak demand loss is reduced.

Distribution Transformers

76. In 1983 when Adair & Brady conducted their study there were 236 distribution transformers on the system providing a total capacity of 14907 kVA. These were mainly relatively large transformers of the high loss type, feeding extensive LV circuits. Unfortunately, 8 more of these transformers were added to the system, providing another 2120 kVA of transformer capacity before the switch to low loss transformers was made. This resulted in an increase in distribution transformer losses from the 1982 level of 2.4% to 2.9% in 1988. During this time 190 new type transformers (6315 kVA) have been added to the system and account for losses of only 0.4% of net generation.

77. Economic analysis has shown that the minimum size transformer to be installed on the system is 15 kVA. Recently, high voltage metering has been applied to three large consumers. This would cause a small reduction in distribution transformer losses.

Low Voltage Lines

78. In 1982 the losses in LV lines stood at some 6.5% of net generation. This high loss was identified as caused by long lengths of LV lines and undersized LV and service drop conductors.

79. To reduce this high loss the LV distribution has been reconfigured using more and smaller transformers, and LV circuits have been restricted to maximum run lengths of 300m (1,000 ft). So far some 123 km of single phase and 6 km of three phase LV lines have been built under the loss reduction project. The rebuild has taken place in the high L.V. loss areas on the Sion Hill, Richmond and Calliaqua feeders.

80. The actual loss reduction achieved by the reconfiguration is not known. However, in the areas of Murray's Village and Glen it is estimated that the loss reduction achieved is about 0.17%. Using this as a base, it would appear that LV losses have been reduced from 6.5% to about 4% of net generation.

81. In 1982 Adair & Brady estimated the level of non-technical losses to be 10.8% of net generation, the major components of these losses being theft of service, unbilled consumers and incorrect metering. The loss reduction programme had reduced non-technical losses to about 3.8% of net generation by the end of 1988.

82. The Adair & Brady report mentioned that VINLEC's meter inspection section was under-staffed. At that time only one meter inspector was responsible for checking the defects reported by meter readers, investigating consumers whose billing records changed significantly and attending to consumers' complaints requiring a field check. This workload was certainly too much for one person and many suspected cases of theft detected by the billing section were not investigated. This led to under-utilisation of the computerised customer management system and high levels of theft.

83. The meter inspection section was upgraded to a full crew (two persons and a vehicle) by the start of the loss reduction programme. One additional crew was employed under Power Loss. Up to the end of March 1989 some 11,861 consumer meter installations were inspected, approximately 77% of the total number of 15,500 consumers in St. Vincent. Of these, less than 900 meter installations met all the required standards. Tampered meters accounted for 91 cases. Some 25% of the meters surveyed required immediate attention.

Theft of Service

84. Illegal use of electricity has been punishable by Law since 1951. In fact, the penalty then was very severe; a fine of up to $500 or two years in prison with or without hard labour.

85. In 1973, the 1951 Act was replaced by a new Law, wherein the penalty for stealing electricity was a maximum fine $500 or up to six months in prison.

The Law also gave VINLEC the right to recover the cost of electricity stolen and to disconnect supply from any consumer found using electricity illegally.

86. Prosecution for theft of service has proved to be difficult. VINLEC has therefore used the Disconnection Clause in the Law of 1973 to put pressure on consumers found stealing to pay the cost of electricity stolen. This approach has worked in 60 of the 91 certified cases of tampering identified during the meter survey. A total of EC$98,160, representing 176,617 KWh of stolen electricity, has been recovered since January 1988.

87. Also, in 1989 judgement was delivered against a large commercial consumer found stealing eleccricity in 1983. This theft of service was discovered during the power loss study. Disconnection pressure failed to have any impact on this consumer and civil action was pursued by VINLEC. In 1989 the consumer was required by the Court to pay EC$53,336 to cover stolen electricity and meter replacement. (See Appendix 20).

88. It must be noted here that meter inspectors found a number of other meters which appeared to have been tampered with. However, in the view of the Company's lawyer, they cannot be categorized as tampered cases unless tampering can be proved beyond doubt.

Meter Replacement/Relocation

89. Meter replacement/relocation measures were initiated early in 1987. It was recommended that priority be given to relocation of three phase meters installed on services to high consumption customers, where a defective meter would have greater impact on loss levels. The main objectives of the measures were:

- to replace bottom connected meters with socket type meters, which are not only water-tight but difficult to tamper with;

- to relocate meters from inside to the outside of houses and buildings in order to detect and prevent meter tampering;

- to relocate meters difficult to read to a more accessible location and so avoid the non-reading of meters

90. To date, 35 three phase demand meters and 138 three phase non-demand meters have been relocated or replaced. This leaves only 12 three phase customers whose meters have not been relocated. The programme is still in progress and all three phase customers' meters should be relocated by end of July 1989.

91. Approximately, 1800 single phase meters have been replaced or relocated to date.

92. Initially, areas for single phase relocation work were chosen at random. As re-configuration work progressed, single phase relocation was scheduled for the areas already re-configured. Within the past year all customers with consumption over 800 KWh per month were also targeted for speedy relocation. To date, 190 of these consumers have had their meters relocated. These include some of the larger three phase comsumers.

93. Local wiremen were hired on contract to do the relocation work. Meters were installed by VINLEC crews.

IMPROVED PRODUCTIVITY

94. The elements of the project geared towards productivity improvement have been completed and have made a tremendous impact on VINLEC's T & D operations.

Office Space and Stores

95. Before the implementation of the power loss project suitable office space for technical staff, workshops and stores facilities were sadly lacking. T & D crews collected materials from the Stores building in the Kingstown Power Station yard. There was little parking space and, consequently, the delivery of materials was slow. In fact, if a truck parked near the gate had a flat tyre, all the other vehicles behind had to wait in the yard until it was repaired. It was estimated that each crew lost about an hour every day collecting materials.

96. The construction of the T & D Complex has provided comfortable offices for all T & D engineering and administrative staff. The complex also include adequate stores and vehicle parking space, auto repair workshop, transformer maintenance workshop and transformer storage shed, meter testing facilities, carpenter workshop, canteen, locker rooms and a conference room.

Vehicles, Tools and Equipment

97. Three modern line trucks and other transportation vehicles have been purchased, and though there are no spares vehicles, the crews are of such size that if one vehicle is taken out of service the crew members can be usefully distributed among the other crews.

98. Sufficient tools and equipment have been purchased to allow the T & D Crews to use modern techniques and methods in line construction and maintenance work.

Training

99. All of the T & D Staff have undergone at least one year of prescribed training. Training is an on-going activity in T & D and the available materials and facilities makes training so much easier for the trainees and the T & D engineering staff.

Organisational Structure

100. The acquisition of proper facilities, transportation, equipment, tools and training, along with improvement of engineering staff, has enabled the T & D Department to restructure its organisation for maximum efficiency and control (see Appendices 15 to 19).

Meter Testing

101. VINLEC's meter testing facility was in 1982 located in the Kingstown Power Station compound. Meters were calibrated with the use of voltage and current measurements, instead of a rotating standard. Meters were only tested when a customer's consumption was in dispute. The test 'laboratory' was a naturally ventilated room next to the carpenter shop. In this environment it was impossible to prevent dust from entering the meters. This situation was improved during the power loss study when the Government meter testing facility at Camden Park was loaned to VINLEC. This test lab has since been turned over to VINLEC and the equipment installed at the new T & D Complex at Cane Hall.

102. The meter testing staff comprises two lab technicians and two members of a field testing crew.

Other Benefits

103. The line rebuilding conducted under the loss reduction programme would ensure that over the next 10 years the amount of line maintenance required on the VINLEC system would be greatly reduced. Also the reliability of the system would be greatly improved and the number of trouble calls would decrease.

EXPENDITURE

104. The estimated cost of most projects and the actual expenditure are often quite different. This was true in the case of the power loss reduction project. Initially, it was proposed that the meter test facility given to VINLEC by the Government be upgraded, and over EC$30,000 was allocated for this.

105. However, since the loss reduction project included the construction of a T & D Complex it was thought that meter test facility should be at the same location. The money allocated for the meter test facility was therefore shifted to the T & D Complex allocation.

106. Only 55% of the money allocated to metering has been spent. In retrospect, this may have been due to an error in programme scheduling, in that greater emphasis should have been placed on metering. The figures will show that the gains from non-technical loss reduction have been tremendous.

107. The amount spent on purchasing tools and equipment has doubled the amount estimated, and is a reflection of how under-equipped the T & D staff was before the project began.

108. The cost of training may appear to have been over-estimated, but this is not really the case. Alongside the CDB loan, there was an IDA loan which included a training component; therefore, some of the training requirements for the power loss project was provided under training financed by IDA funds. VINLEC had also improved its technical staff to an extent which will facilitate more in-house training, thus reducing the need for more foreign lecturers. The amount of money spent on line reconfiguration has almost doubled the estimated amount. This is due to the fact that during the orignal study it was assumed that the existing HV system required only minimal work. As stated before, this was erroneous. In addition, the terrain in St. Vincent makes line building an expensive exercise.

109. Interest costs were reduced, as the withdrawal of funds was delayed for several reasons, some of them mentioned before.

110. Appendix 12 shows that scarely any money has been spent on capacitors. This will soon change, however, as the capacitors have arrived in St. Vincent and installation has now begun.

111. The amount spent on engineering services was less than that allocated. This is because the need for engineering services declined as VINLEC engineering staff improved.

MAINTAINING LOW LOSS LEVELS

Technical Losses

112. The Planning Engineer in the T&D Department will be directly responsbile for monitering technical losses and maintaining them at the low levels established during the loss reduction project.

113. The elements of a control plan to maintain low technical loss levels would include the following:

- Proper planning of new HV lines including loss consideration
- Monitoring of feeders to assess load and need for load balancing
- Installation of capacitors to maintain established system power factor
- Close monitoring of transformer loads and voltage levels on LV ciruits
- Proper planning of LV systems including voltage drop and loss considerations
- Continuing proper mapping of both HV and LV network
- Carrying out load flow studies to determine optimum system configuration and to avoid voltage and kVAR flow problems
- Carrying out maintenance work to the same standard as new construction
- Monitoring fault reports closely to identify potential problem areas
- Planning and executution of programme to correct all discovered defects and abnormalties
- Strengthening the Maintenance division.
- Establishing a record-keeping system for data collection

Procurement

114. Attention must be focused on material procurement, as it has been seen that lack of proper material and equipment can lead to improper work

methods and faulty installations. This in time will result in loss of productivity and increase in losses.

115. The T&D Engineer will be directly responsible for procurement of T&D materials and equipment. He will ensure that:

Minimum stock levels are maintained;
Materials ordered meet VINLEC's specifications;
Transformer bid evaluation take losses into account;
Emergency materials are in stock during the hurricane season.

116. He will also keep abreast of new product information so that the best materials and equipment can be obtained.

Non-Technical Losses

117. The non-technical losses on the VINLEC system have been reduced considerably. However, the project programmes have to be completed in order to reach as close to 0% as possible. The Metering and Protection Engineer will be directly responsible for the execution of a control plan, designed to maintain low non-technical loss levels. The elements of the control plan are already in place. These can be identified as:

Review of billing records
Replacement/Relocation of meters
Meter testing
Inspections
Meter reading reports

Review of Billing Records

118. The computerised billing system used by VINLEC since 1982 is an adequate tool for proper consumer management. The system allows a consumer's accounts for the preceding 12 months to be reviewed. It also provides a list of possible billing errors or problems by comparing three months' billing and identifying, through print-out, any consumption pattern which changes rapidly (up or down) from previous months. The computer also processes meter records; the meter number, date of installation, location and condition of meter are all available on the computer. Of course, this information depends on input from meter installation crews, meter inspectors and meter readers and must therefore be constantly updated.

119. The computer also prints out meter defects by category on a monthly basis. The more serious faults can therefore be immediately addressed.

120. Identification of anomalies in consumption pattern and print-out of meter defects must go hand in hand with inspection. All suspect services should be investigated and a programme drawn up and executed to deal with meter defects on a monthly basis.

Meter Replacement/Relocation

121. Meter replacement and/or reloaction will continue until all meter installations on the VINLEC system meet all required standards. Once this has

been achieved close attention will be paid to meter reading reports to ensure that the system is maintained in this condition.

<u>Meter Testing</u>

122. A comprehensive programme for field and laboratory testing of meters will be established and maintained to ensure continuous accuracy in measuring power generated and consumed.

123. At present all new meters are tested before installation and meters are field tested or laboratory tested as requested by the Generation and Billing Departments. The programme will be expanded, however, so that all power station meters, together with metering from industrial and other large consumption customers, will be tested once a year. Other consumer meter testing will be initiated on an 'as necessary' basis, with priority given to suspect installations where there is evidence of tampering.

<u>CONCLUSION</u>

124. VINLEC staff awareness of the benefits of reducing losses and maintaining low power loss levels has been heightened tremendously. This is as a direct result of the execution of a loss reduction project in St. Vincent. One can say with confidence that the loss levels on the VINLEC system will never reach 15% again.

APPENDIX

Appendix

Map of St. Vincent 1

Generating Capacity 2

Transformer Capacity Total 3

Transformer Capacity New 4

Transformer Capacity Old 5

Single Line Diagram 1984 6

Single Line Diagram 1989 7

Peak Demand 1980 - 2001 8

Load Growth 1980 - 2001 9

Load and Demand Growth 1980-2001 10

Cumulative Twelve Months System Losses 11

Allocation of Funds 12

Use of Funds 1986 - present 13

Table of Extensions Required 14

T & D Supervisory Staff 15

T & D Planning Section 16

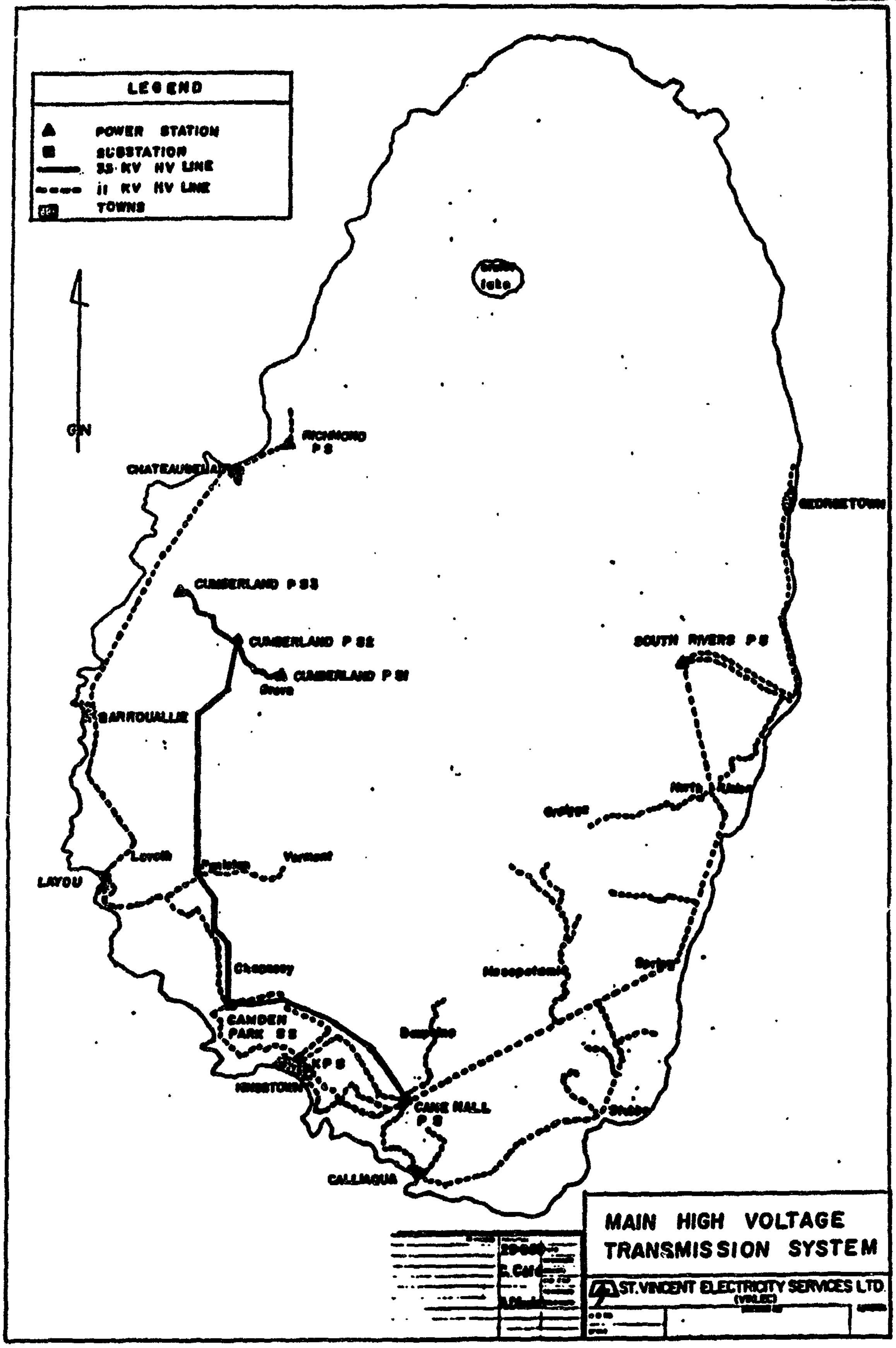
T & D Maintenance Section 17

T & D Construction Section 18

T & D Outstations 19

Test Case 20

Appendix 1


LEGEND
POWER STATION
SUBSTATION
33 KV HV LINE
11 KV HV LINE
TOWNS
RICHMOND P S
CHATEAUBELAIR
GEORGETOWN
CUMBERLAND P S3
CUMBERLAND P S2
CUMBERLAND P S1
SOUTH RIVERS P S
BARROUALLIE
LAYOU
CAMDEN PARK SS
KINGSTOWN
CANE HALL P S
CALLIAQUA
MAIN HIGH VOLTAGE TRANSMISSION SYSTEM
ST. VINCENT ELECTRICITY SERVICES LTD.

ST VINCENT ELECTRICITY SERVICES LTD.
GENERATING CAPACITY

STATION	TYPE	UNIT NO.	UNIT SIZE	INSTALLED CAPACITY
SOUTH RIVERS	HYDRO	NO.1 NO.2 NO.3	320 KW 275 KW 275 KW	870 KW
CANE HALL	DIESEL	NO.1 NO.2 NO.3 NO.4 NO.6 NO.7 NO.8	1126 KW 1260 KW 1260 KW 3200 KW 600 KW 600 KW 600 KW	8646 KW
CUMBERLAND	HYDRO	NO.1 NO.2 NO.3 NO.4 NO.5	1464 KW 640 KW 640 KW 475 KW 475 KW	3694 KW
RICHMOND	HYDRO	NO.1 NO.2	550 KW 550 KW	1100 KW
KINGSTOWN•	DIESEL	NO.1 NO.2 NO.4	315 KW 360 KW 460 KW	1035 KW
				15345 KW

•Kingstown power station is near retirement. Only three of the four units are operational and they are maintained for emergency use only.

Appendix 2

ST.VINCENT ELECTRICITY SERVICES LIMITED DISTRIBUTION CHART FOR MAY 1989

SHOWING TOTAL TRANSFORMER AND TOTAL KVA CAPACITY ON THE SYSTEM(ST VINCENT)

TOTAL

ZONE	800 KVA	630 KVA	500 KVA	400 KVA	315 KVA	300 KVA	250 KVA	200 KVA	150 KVA	100 KVA	112 KVA	75 KVA	50 KVA 3 PH	50 KVA 1 PH	25 KVA 3 PH	25 KVA 1 PH	16 KVA	15 KVA	10 KVA	5 KVA	TOTAL TRANS IN ZONE	CAPACITY IN KVA: IN ZONE	INCREASE	DECREASE
(1) K.TOWN - FLOUR MILL	1	0	5	1	2	0	4	1	1	1	0	3	1	3	0	6	0	17	1	0	47	6620	0	0
(2) K/TOWN - CAMDEN PARK	0	0	0	0	0	0	0	0	0	1	0	0	4	1	0	7	5	7	0	0	25	710	30	0
(3) CAMDEN PARK - RICHMOND	0	1	1	0	1	0	1	2	1	0	0	0	7	4	3	17	13	8	1	8	62	3638	0	0
(4) BELMONT - CANE HALL	0	0	0	0	0	0	0	0	0	1	0	0	3	1	1	17	2	10	9	4	39	952	0	0
(5) CANE HALL - SION HILL	0	0	1	0	1	0	1	1	0	5	0	0	1	3	0	10	0	14	0	0	37	2425	0	50
(6) CANE HALL - C/GARDEN	0	0	2	0	0	1	1	0	2	4	0	0	0	1	0	14	0	5	0	0	30	2725	50	75
(7) CANE HALL - PROSPECT	0	0	1	0	0	0	0	1	0	5	1	0	1	15	0	31	6	28	0	6	95	3433	200	200
(8) YAMBOU - SOUTH RIVERS	0	0	0	0	0	0	0	0	0	0	0	0	3	1	0	12	14	10	0	5	46	914	0	0
(9) SOUTH RIVERS - G/TOWN	0	0	0	0	0	0	0	1	0	2	0	0	2	0	0	7	5	3	0	2	22	810	0	0
(10) INTERCONNECTOR	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	8	1	20	0	0	31	1116	85	0
TOTAL TRANSFORMERS	1	1	11	1	4	1	7	6	4	21	1	3	22	29	1	129	46	119	2	25	434	434	Tot.Inc	Tot.Dec
CAPACITY	800	630	5500	400	1260	300	1750	1200	600	2100	112	225	1100	1450	25	3225	736	1785	20	125	23343	23343	365	325

1.REMOVED 100KVA (BURNT) AND INSTALLED 100KVA AT GLOVE FACTORY (24/5/89)

Appendix 4

ST.VINCENT ELECTRICITY SERVICES LIMITED DISTRIBUTION CHART FOR MAY 1989

SHOWING TOTAL TRANSFORMER AND TOTAL KVA CAPACITY ON THE SYSTEM(ST VINCENT)

NEW

ZONE	1000 KVA	630 KVA	500 KVA	400 KVA	315 KVA	300 KVA	250 KVA	200 KVA	150 KVA	100 KVA	112 KVA	75 KVA	50 KVA 3 PH	50 KVA 1 PH	25 KVA 3 PH	25 KVA 1 PH	16 KVA	15 KVA	10 KVA	5 KVA	TOTAL TRANS IN ZONE	CAPACITY IN KVA IN ZONE	CAPACITY IN KVA INCREASE	CAPACITY IN KVA DECREASE	
(1) K/TOWN - FLOUR HILL			2											1		4		16			23	1390	0	0	
(2) K/TOWN - CAMDEN PARK																1		7			8	130	30	0	3/5
(3) CAMDEN PARK - RICHMOND														3		6		2			11	330	0	0	11/12
(4) BELMONT - CANE HALL													1	1		5		5			12	300	0	0	
(5) CANE HALL - SION HILL										2						8		14			24	610	0	0	
(6) CANE HALL - C/GARDEN			1							1			0	1		6		5			14	875	50	0	1/6/9
(7) CANE HALL-PROSPECT										1				10		18		27			56	1455	200	0	2
(8) YAMBOU - SOUTH RIVERS																5		7			12	230	0	0	4/8/10/13
(9) SOUTH RIVERS - B/TOWN																2		3			5	95	0	0	
(10) INTERCONNECTOR			1													4		20			25	900	85	0	7
TOTAL TRANSFORMERS	0	0	4	0	0	0	0	0	0	4	0	0	1	16	0	59	0	106	0	0	190	190	Tot.Inc	Tot.Dec	
CAPACITY	0	0	2000	0	0	0	0	0	0	400	0	0	50	800	0	1475	0	1590	0	0	6315	6315	365	0	

1 INSTALLED 1 25KVA AT LONG WALL (4/5/89)
2. INSTALLED 1 25KVA AT VILLA (SUNSET SHORES) (10/5/89)
3. INSTALLED 1 3 PHASE 25KVA AT LOWMANS LD. O. T.JOHN (15/5/89)
4 INSTALLED 1 15KVA AT GREGGS NEAR BOIING PLANT (18/5/89)
5 INSTALLED 100KVA 3 PHASE AT GLOVE FACTORY (24/5/89)
6. INSTALLED 1 25KVA NEAR TO TROTMAN CANE GARDEN (24/5/89)
7. INSTALLED 1 15KVA AT QUEENS DRIVE SUSPENSE JOB (26/5/89)
8. INSTALLED 1 25KVA AT GREGGS NEXT TO TUSKSON SHOP (19/5/89)
9. INSTALLED 1 25KVA NEXT TO CROSBY AT LOWER CANE GARDEN (22/5/89)
10. INSTALLED 15KVA 1 PHASE AT BELLE VUE (NEXT TO DA SILVA) (19/5/89)
11. INSTALLED 1 15KVA AT SPRING
12. INSTALLED 1 25KVA AT SPRING
13. INSTALLED 1 15KVA AT BRIDGETOWN (REDISFORD)

ST.VINCENT ELECTRICITY SERVICES LIMITED DISTRIBUTION CHART FOR MAY 1989.

SHOWING TOTAL TRANSFORMER AND TOTAL KVA CAPACITY ON THE SYSTEM(ST VINCENT)

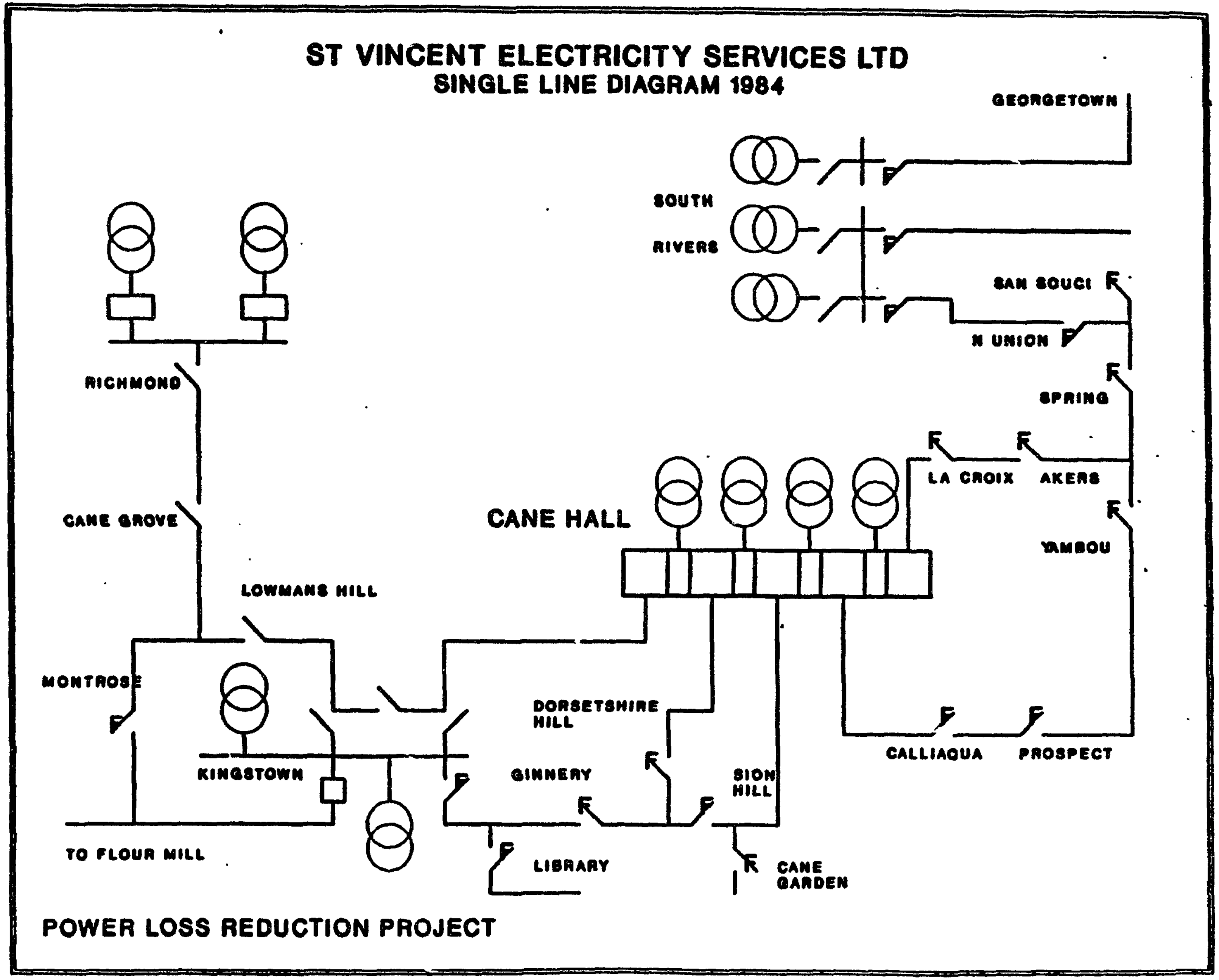
SLB

ZONE	800 KVA	630 KVA	500 KVA	400 KVA	315 KVA	300 KVA	250 KVA	200 KVA	150 KVA	100 KVA	112 KVA	75 KVA	50 KVA 3 PH	50 KVA 1 PH	25 KVA 3 PH	25 KVA 1 PH	16 KVA	15 KVA	10 KVA	5 KVA	TOTAL TRANS IN ZONE	CAPACITY IN KVA		
																						IN ZONE	INCREASE	DECREASE
(1) K/TOWN - FLOUR MILL	1		3	1	2		4	1	1	1		3	1	2		2		1	1		24	5230	0	0
(2) K/TOWN - CAMDEN PARK										0			4	1		6	5				17	560	0	0
(3) CAMDEN PARK - RICHMOND		1	1	0	1		1	2	1	1			7	1		11	13	2	1	8	51	3308	0	0
(4) BELMONT - CANE HALL										1			2		1	12	2	5		4	27	652	0	0
(5) CANE HALL - SION HILL			1		1		1	1		3			1	3		2	0				13	1815	0	50
(6) CANE HALL - C/GARDEN			1			1	1		2	3				0		7					16	1850	0	75
(7) CANE HALL - PROSPECT			1					1		3	1		1	5		13	6	1		6	39	1978	0	200
(8) YAMBOU - SOUTH RIVERS													3	1		7	14	4		5	34	684	0	0
(9) SOUTH RIVERS - G/TOWN								1		2			2			5	5			2	17	715	0	0
(10) INTERCONNECTOR										1						4	1				6	216	0	0
TOTAL TRANSFORMERS	1	1	7	1	4	1	7	6	4	17	1	3	21	13	1	70	46	13	2	25	244	244	Tot.Inc	Tot.Dec
CAPACITY	800	630	3500	400	1260	300	1750	1200	600	1700	112	225	1050	650	25	1750	736	195	20	125	17928	17029	0	325

1 REMOVED 25KVA FROM CANE GARDEN NEXT TO D.E.C.S. (24/5/89)
2. REMOVED BURNT 100KVA 3 PHASE FROM GLOVE FACTORY (24/5/89)
3. REMOVED 100KVA 3 PHASE FROM VILLA (SUNSET SHORES); (10/5/89)

Appendix 5

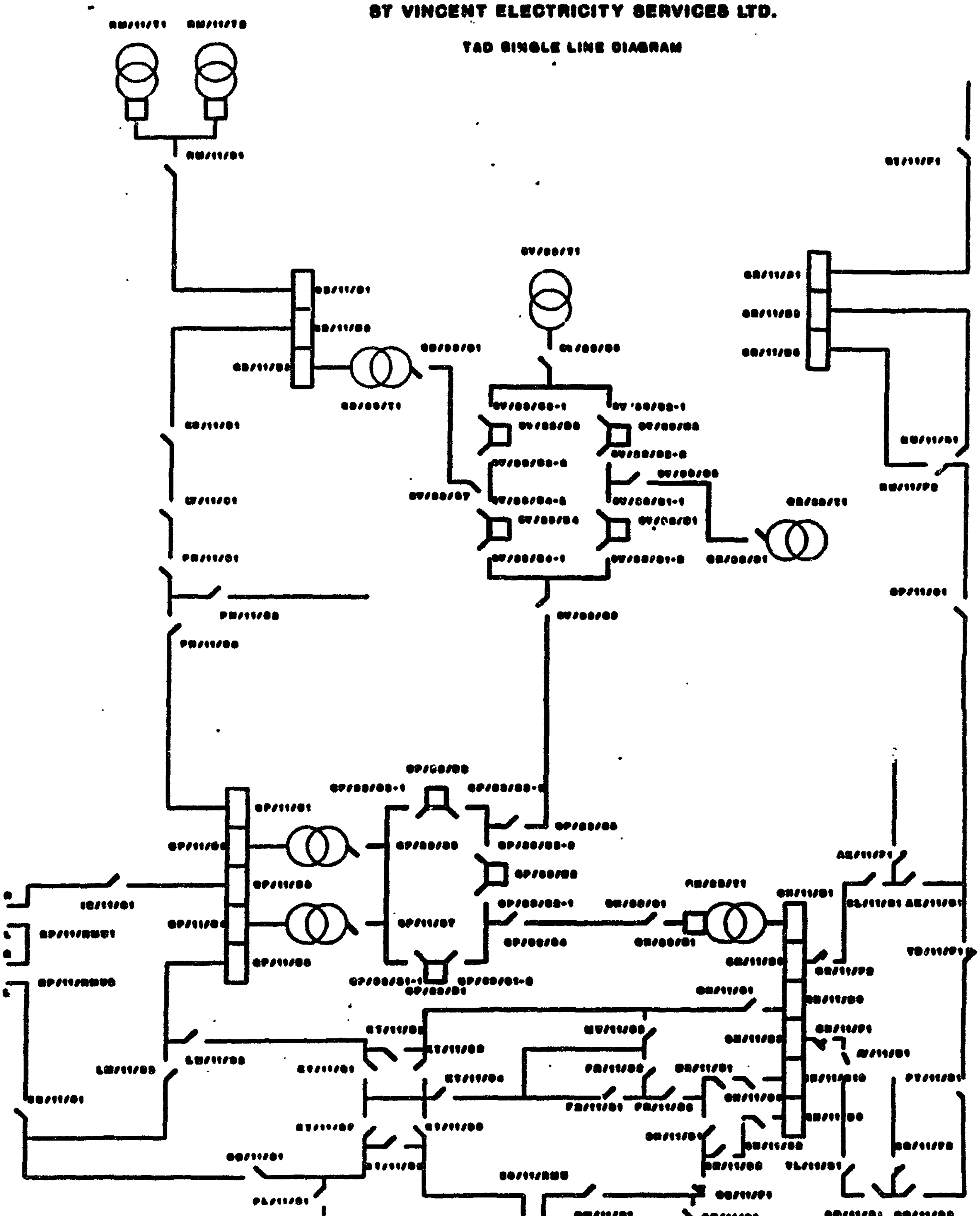
Appendix 6


ST VINCENT ELECTRICITY SERVICES LTD
SINGLE LINE DIAGRAM 1984
GEORGETOWN
SOUTH
RIVERS
SAN SOUCI
N UNION
SPRING
LA CROIX
AKERS
YAMBOU
RICHMOND
CANE GROVE
CANE HALL
LOWMANS HILL
MONTROSE
KINGSTOWN
DORSETSHIRE HILL
GINNERY
SION HILL
CALLIAQUA
PROSPECT
TO FLOUR MILL
LIBRARY
CANE GARDEN
POWER LOSS REDUCTION PROJECT

Appendix 7

ST VINCENT ELECTRICITY SERVICES LTD.

TAD SINGLE LINE DIAGRAM

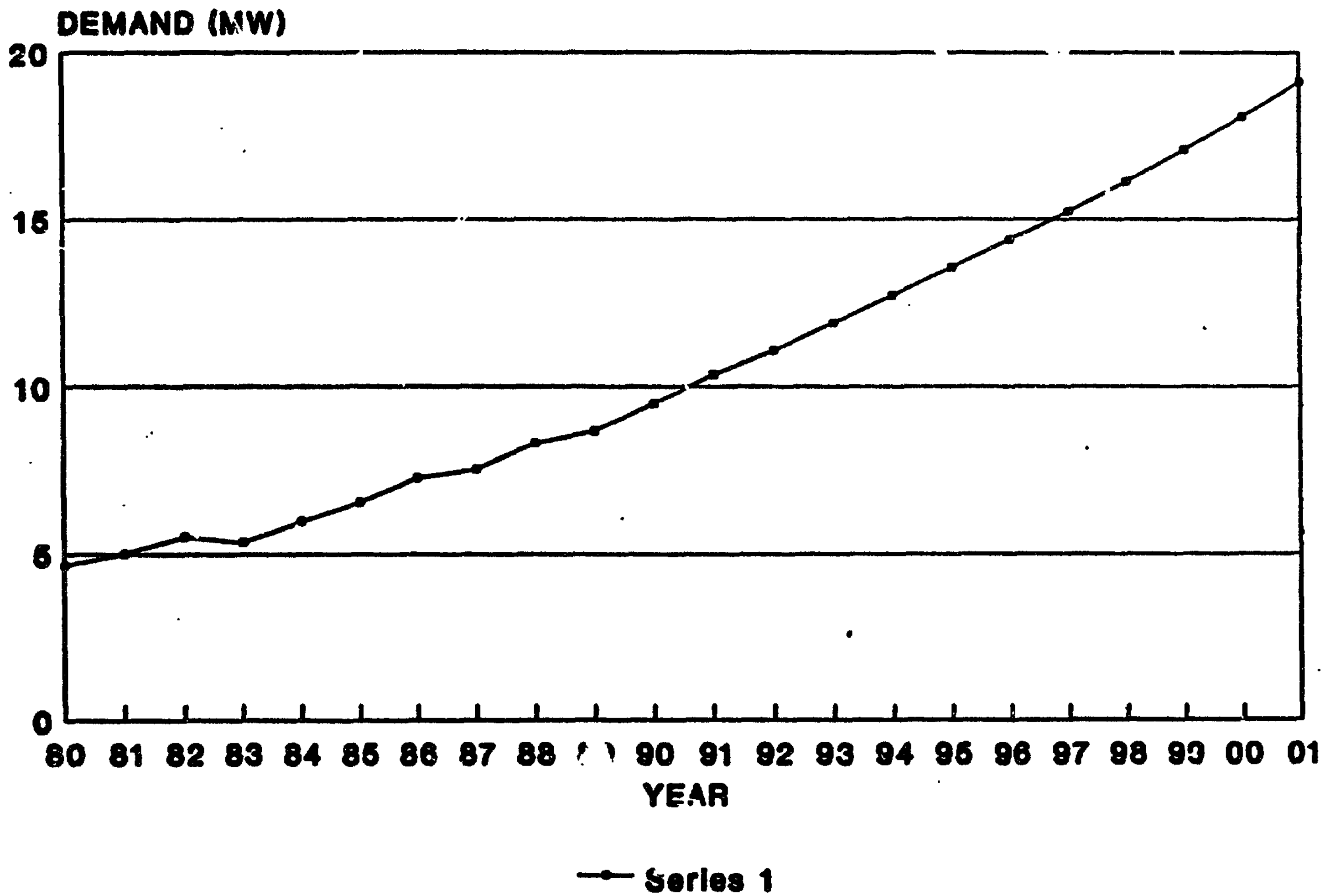


10 APR 1988(DESTROY ALL PREVIOUS COPIES)

Appendix 8

STVINCENT ELECTRICITY SERVICES LTD.

DEMAND GROWTH 1980 - 2001



POWER LOSS REDUCTION PROJECT

ST VINCENT ELECTRICITY SERVICES LTD

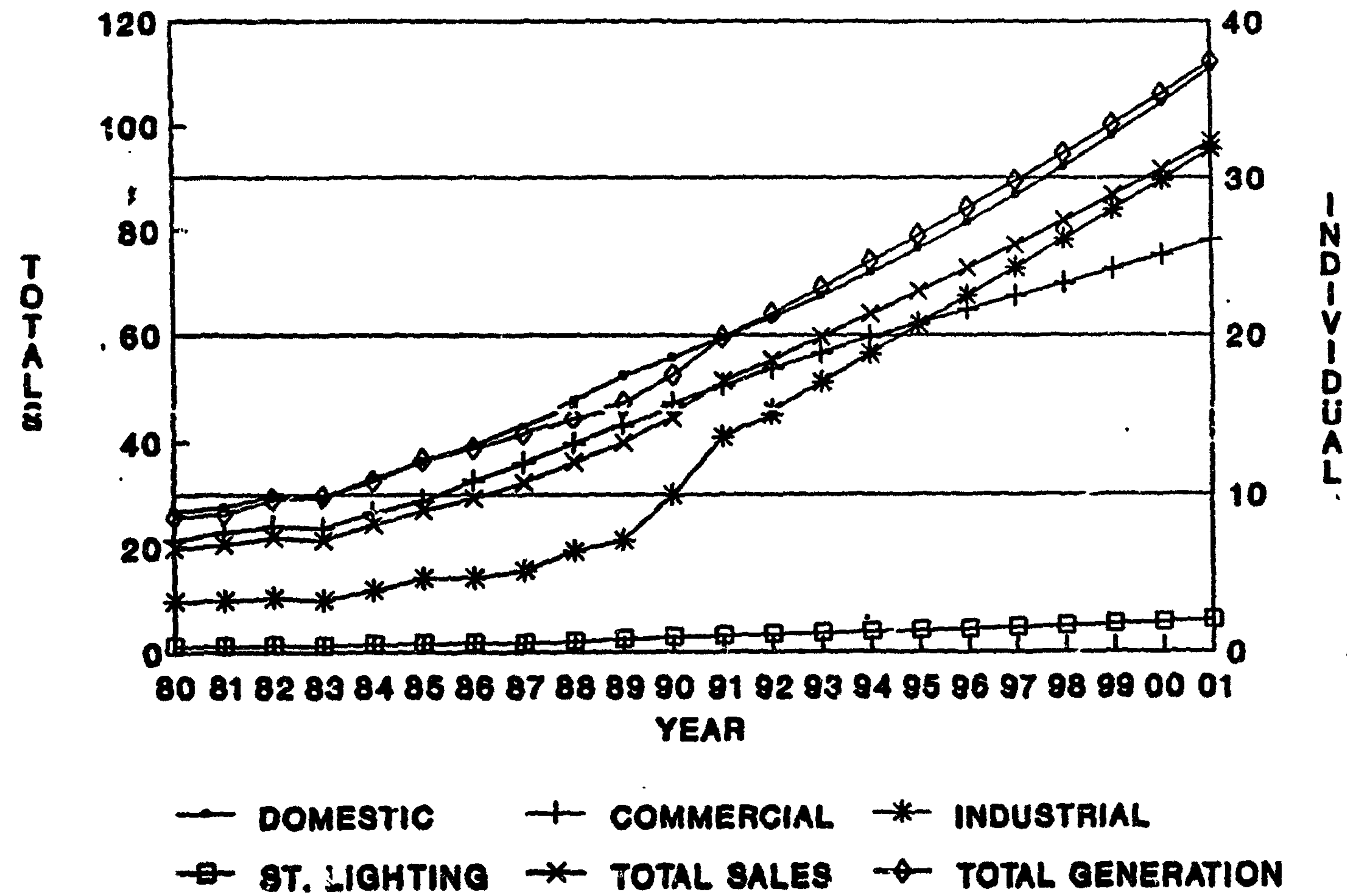
POWER LOSS REDUCTION PROJECT

LOAD GROWTH AND ESTIMATION 1980 - 2001

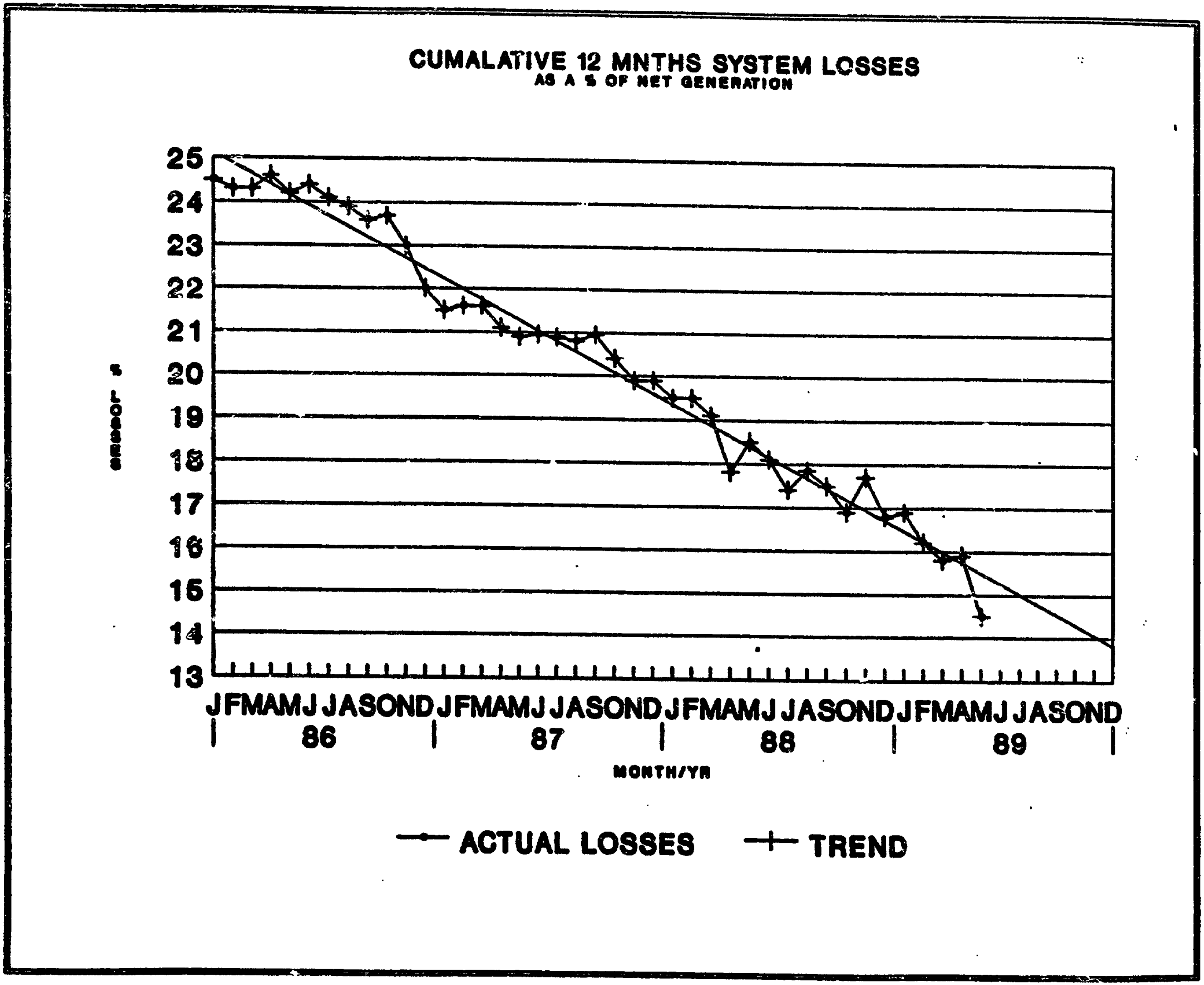
YEAR	DOMESTIC SALES (GWH)	DOMESTIC CONSUMER NO	DOMESTIC GROWTH %	COMMERCIAL SALES (GWH)	COMMERCIAL CONSUMER NO	COMMERCIAL GROWTH %	INDUSTRIAL SALES (GWH)	INDUSTRIAL CONSUMER NO	INDUSTRIAL GROWTH %	STREET LIGHTING SALES (GWH)	STREET LIGHTING CONSUMER NO	STREET LIGHTING GROWTH %	TOTAL SALES (GWH)	ANNUAL GROWTH %	LOSSES AS % OF NETT: TECH. %	LOSSES AS % OF NETT: NON TECH %	GENERATION NETT (GWH)	GENERATION GROSS (GWH)	ANNUAL GROWTH %	LOAD FACTOR %	ANNUAL PEAK (MW)	ANNUAL GROWTH %
1980	8.93	9597		7.16	1148		3.23	42		0.39	30		19.66		12.5	9.2	25.11	25.75		63.10	4.66	
1981	9.17	9883	2.69	7.60	1157	6.09	3.24	39	0.31	0.39	30	0.00	20.40	3.76	12.5	7.8	25.60	26.26	1.98	59.00	5.01	7.64
1982	9.97	10107	8.72	7.97	1190	4.87	3.44	39	6.17	0.40	40	2.56	21.78	6.76	12.5	10.8	28.40	29.03	10.55	60.00	5.52	10.18
1983	9.74	10744	-2.31	7.87	1210	-1.25	3.31	41	-3.78	0.40	39	0.00	21.32	-2.11	12.5	14	29.01	29.62	2.03	63.20	5.35	-3.13
1984	11.01	11107	13.04	8.83	1285	12.20	3.93	38	18.73	0.50	45	25.00	24.27	13.84	12.5	11.1	31.77	32.48	9.66	62.20	5.96	11.42
1985	12.11	11723	9.99	9.59	1315	8.61	4.68	37	19.08	0.55	47	10.00	26.93	10.96	12.5	10.9	35.16	36.50	12.38	63.70	6.54	9.73
1986	13.11	12231	8.26	10.87	1373	13.35	4.71	41	0.64	0.57	47	3.64	29.26	8.65	12.5	9.5	37.51	38.83	6.38	63.10	7.25	10.91
1987	14.45	12762	10.22	12.01	1409	10.49	5.14	40	9.13	0.59	50	3.51	32.19	10.01	11.3	8.5	40.14	41.57	7.06	63.17	7.51	3.59
1988	15.85	13564	9.69	13.27	1565	10.49	6.38	39	24.12	0.68	50	15.25	36.18	12.40	10.3	6.5	43.49	44.97	8.18	61.85	8.30	10.49
EST.																						
1989	17.44	14649	10.00	14.50	1679	9.30	7.11	42	11.50	0.82	50	20.00	39.87	10.20	9	3.5	45.56	47.11	4.77	62.00	8.67	4.31
1990	18.59	15323	6.60	15.69	1783	8.20	9.93	50	39.60	0.94	51	15.00	45.15	13.24	8.5	2.5	50.73	52.35	11.12	63.00	9.49	9.35
1991	19.81	16028	6.60	16.82	1876	7.20	13.65	58	37.50	1.03	51	10.00	51.32	13.68	8.5	2.5	57.67	59.40	13.46	63.50	10.35	9.13
1992	21.10	16709	6.50	17.87	1955	6.20	15.18	61	11.20	1.11	51	8.00	55.27	7.68	8.5	2.5	62.10	63.96	7.68	66.00	11.06	6.87
1993	22.47	17503	6.50	18.87	2025	5.60	17.01	64	12.00	1.19	51	7.00	59.54	7.73	8.5	2.5	66.90	68.90	7.73	66.20	11.88	7.40
1994	23.93	18290	6.50	19.85	2090	5.20	18.83	66	10.70	1.27	52	6.80	63.88	7.29	8.5	2.5	71.78	73.93	7.29	66.40	12.71	6.97
1995	25.49	19115	6.50	20.74	2182	4.50	20.65	68	9.70	1.36	52	6.80	68.24	6.83	8.5	2.5	76.68	78.98	6.83	66.60	13.54	6.51
1996	27.10	19974	6.30	21.61	2189	4.20	22.47	69	8.80	1.45	52	6.80	72.68	6.50	8.5	2.5	81.66	84.11	6.50	66.80	14.37	6.18
1997	28.88	20855	6.40	22.46	2231	3.90	24.29	70	8.10	1.55	53	6.80	77.18	6.19	8.5	2.5	86.72	89.32	6.19	66.70	15.24	6.05
1998	30.73	[illegible]	6.40	23.31	2271	3.80	26.11	70	7.50	1.66	53	6.80	81.81	6.00	8.5	2.5	91.92	94.68	6.00	67.00	16.13	5.84
1999	32.70	22720	6.40	24.19	2312	3.80	27.94	70	7.00	1.77	53	6.80	86.60	5.86	8.5	2.5	97.30	100.22	5.86	67.00	17.08	5.86
2000	34.79	23720	6.40	25.11	2359	3.80	29.84	70	6.80	1.89	53	6.80	91.63	5.81	8.5	2.5	102.96	106.05	5.81	67.00	18.07	5.81
2001	37.02	24772	6.40	26.07	2396	3.80	31.84	70	6.70	2.02	53	6.80	96.94	5.79	8.5	2.5	108.92	112.19	5.79	67.00	19.12	5.79

Appendix 9

ST VINCENT ELECTRICITY SERVICES LTD
LOAD & DEMAND GROWTH 1980 - 2001



POWER LOSS REDUCTION PROJECT



CUMALATIVE 12 MNTHS SYSTEM LOSSES
AS A % OF NET GENERATION
LOSSES %
25
24
23
22
21
20
19
18
17
16
15
14
13
JFMAMJ JASOND JFMAMJ JASOND JFMAMJ JASOND JFMAMJ JASOND
86
87
88
89
MONTH/YR
ACTUAL LOSSES
TREND

Appendix 11

ALLOCATION OF FUNDS

	1986		1987		1988		1989 to APRIL		TOTAL TO DATE		ESTIMATED COSTS
12. METERS											
Testing			9722.22		19.5		88954.[illegible]		98773.31		
Purchases	722.57		130773.0		494160.91		142598.77		758256.15		
Salary/Wages	15142.06		90876.31		210424.39		85190.48		401433.34		
Petty Contracts		15864.73	74195.22	305559.60	152941.05	847546.45	48452.44	365225.77	275588.31	1534017.61	2782967.70
13. CAPACITOR PURCHASES				1648.13						1648.13	164570.26
14a HIGH VOLTAGE RECONFIG.											
Salary/Wages	52443.90		69646.97		173213.94		53124.09		348428.90		
Purchases	112812.29		918316.61		1632984.95		483747.56		3146961.46		
Petty Contracts	1600.00		43752.81		179441.95		56271.39		281106.15		
14b LOW VOLTAGE RECONFIG.											
Salary/Wages	43155.22		85101.10		140218.7		46401.62		314876.64		
Purchases	67284.27		246308.08		902120.82		305392.63		1521113.80		
Petty Contracts	6655.00		94645.83		206409.6		204737.48		512438.91		
14c TRANSFORMERS											
Salary/Wages	504.39		10780.19		14915.26		1490.88		27690.72		
Purchases	6538.43		100836.83		135305.49		53275.42		295956.17		
Petty Contracts					139.06		2000.00		2139.06		
14d CROP COMPENSATION	2258.50		6752.20		50935.77		5367.50		65313.97		
14e LINE CONTRACTORS					646770.8		232108.40		878879.20		
14 TOTAL		293291.95		1576148.62		4081555.34		1444127.07		7395122.98	6451669.13
15 PURCHASE VEHICLES		90557.00		591552.00						672109.00	597602.86
16 TRAINING		8772.10		48757.11		33613.43				91142.64	272496.11
17a PURCHASE TOOLS			7906.36		335.99						
17b PURCHASE INSTRUMENTS	97833.96		1684.33		18944.21						
17 TOTAL		97833.96		8690.69		19300.19				125824.84	53959.63
18 LAND FOR T&D CENTRE		177650.00								177650.00	202348.60
19 CONSTRUCT T&D CENTRE		1007645.92		1711224.70		1025054.42		29791.53		3774746.57	3604503.00
110 ENGINEERING SERVICES		316493.66		213408.23		2489.14				532391.03	802649.43
111 PROJECT MANAGEMENT		[illegible].03		233186.67		261724.82		22611.94		775555.46	824233.28
INTEREST		22895.33		293374.24		867238.33				1183507.90	3131000.00
FINANCE CHARGES		97.21		24510.41		2555.39				27163.61	
MISCELLANEOUS		8412.69		16181.98		10484.81		660.61		35740.09	
TOTAL		2287549.18		5024693.44		7151962.32		1862416.92		16326621.86	16830000.00

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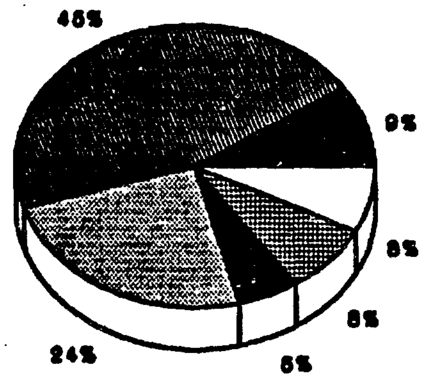
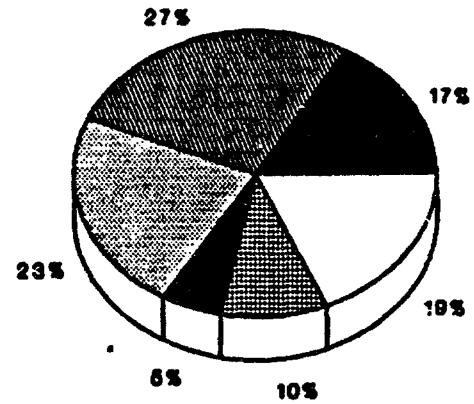
Appendix 12
Page 1 of 2

ST VINCENT ELECTRICITY SERVICES LTD.
POWER LOSS REDUCTION PROJECT



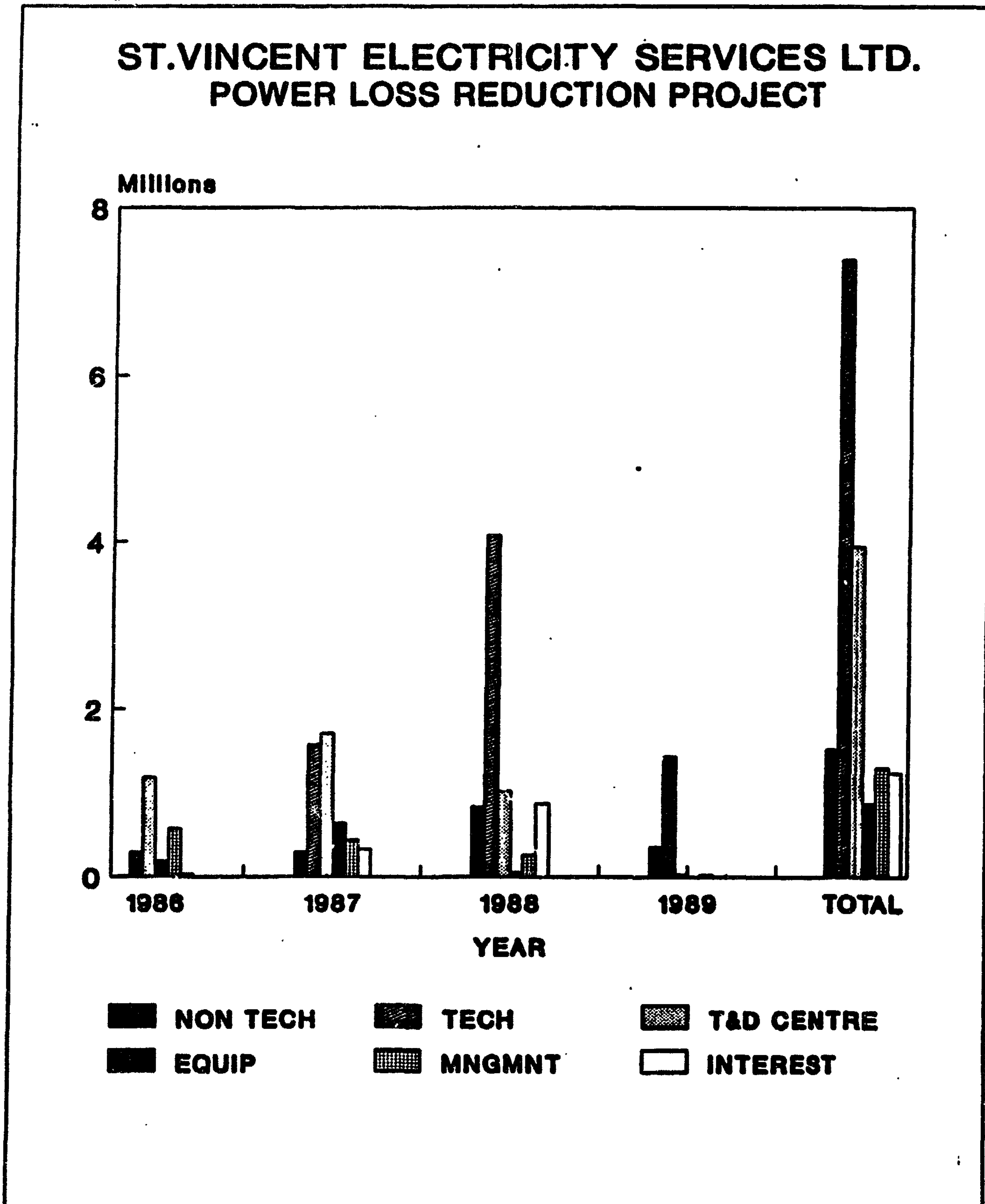
ACTUAL COSTS



ESTIMATED COSTS

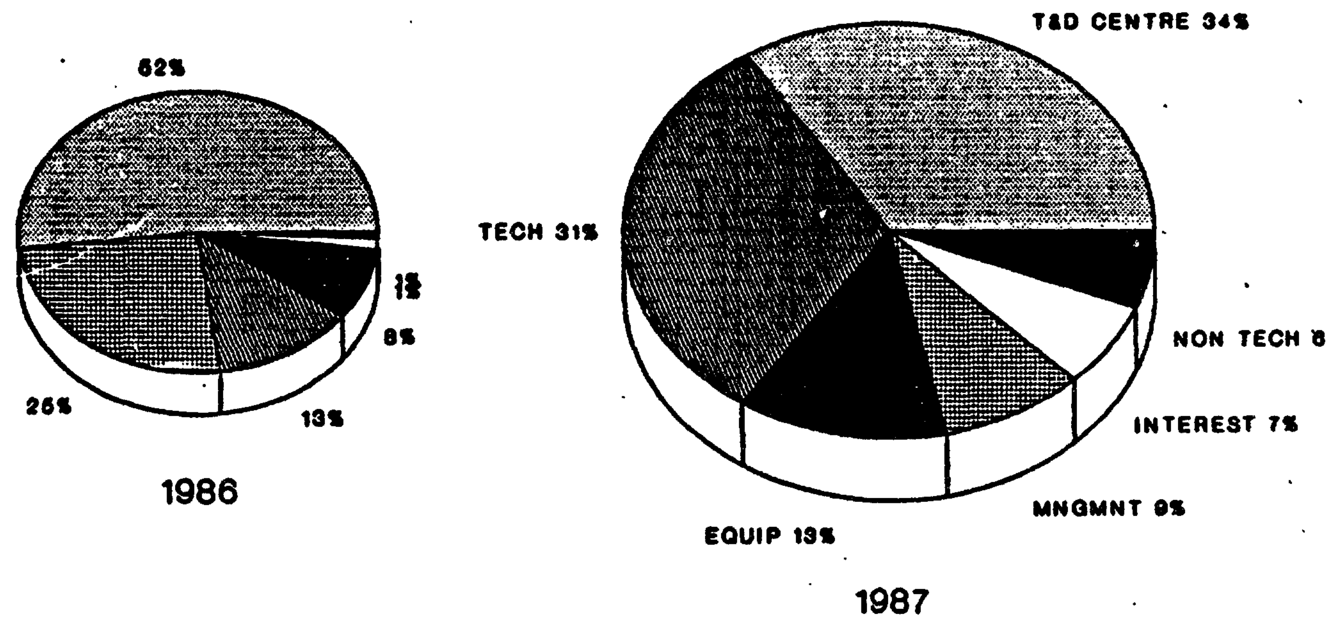
ST VINCENT ELECTRICITY SERVICES LTD. POWER LOSS REDUCTION PROJECT.

	1986	1987	1988	1989	TOTAL	ESTIMATED COSTS
A. NON TECHNICAL LOSSES	15864.73	305380.66	847546.45	365225.77	1534017.61	2782967.70
B. TECHNICAL LOSSES	293291.95	1577796.75	4081555.34	1444127.07	7396771.11	4558239.39
C. T & D CENTRE	1185295.92	1711854.70	1025454.42	29791.53	3952396.57	3806851.60
D. TRAIN. EQUIP & VEHICLES	187165.06	648999.80	52913.62	0.00	889078.48	924058.59
E. ENGIN. & PROJ. MANAGEMENT	574525.69	446594.90	264213.96	22611.94	1307946.49	1626882.72
F. INTEREST & MISC.	31405.83	334066.63	880278.53	660.61	1246411.6	3131000
TOTAL	2287549.18	5024693.44	7151962.32	1862416.92	16326621.86	16830000

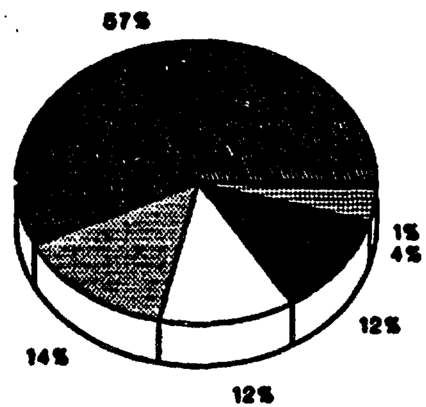

ST.VINCENT ELECTRICITY SERVICES LTD.
POWER LOSS REDUCTION PROJECT
Millions
8
6
4
2
0
1986
1987
1988
1989
TOTAL
YEAR
NON TECH
TECH
T&D CENTRE
EQUIP
MNGMNT
INTEREST

ST VINCENT ELECTRICITY SERVICES LTD

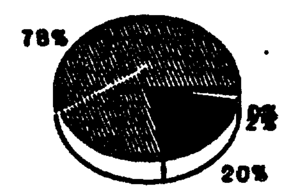
POWER LOSS REDUCTION PROJECT



ST VINCENT ELECTRICITY SERVICES LTD
POWER LOSS REDUCTION PROJECT



1988



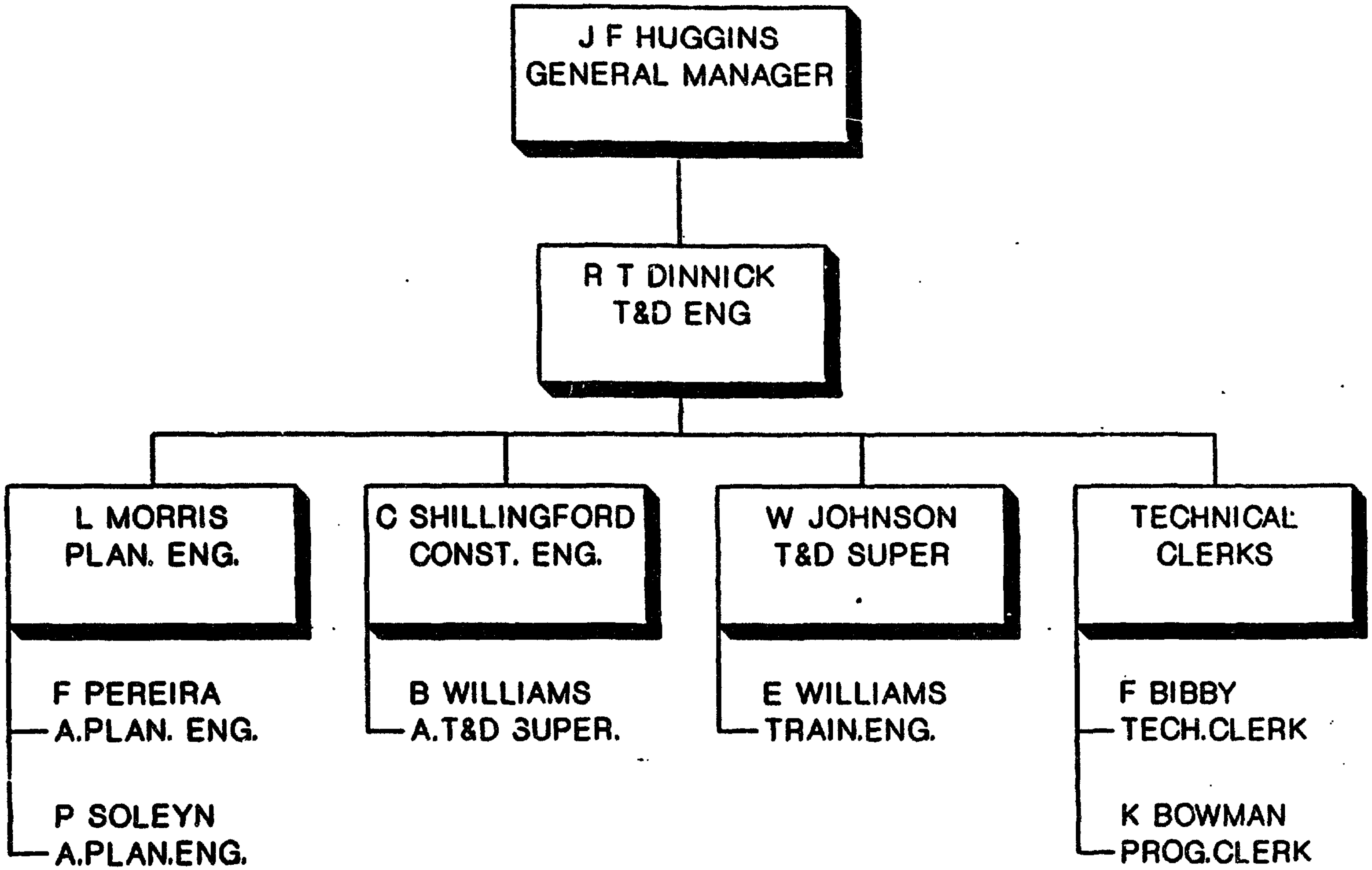
1989 TO APRIL

TABLE OF EXTENSIONS REQUIRED

AREA	POTENTIAL CNNCTS	LINE EXTENSIONS		A.B.S		POLES		TXFMS	STATUS AS AT 26/6/89
		KM. HV.	KM. LV.		H.V.	UND BLD	L.V.		
BOM BOM	10		.5				10	1	Completed
VILLA	18	.2	.7	1	4	4	10	2	In Progress
GREGGS	31	.75	1.50		15	10	20	3	In Progress
LOWMANS LEEWARD	28	.75	1.75		15	10	25	3	Sched 3 Qrt 89
LOWMANS WINDWARD	17	.9	2.25		18	15	30	2	Sched 3 Qrt 89
RICHLAND PARK	22	.5	1.50		10	10	20	2	In Progress
MESOPOTAMIA	36	1.00	3.00		20	20	40	4	Sched 4 Qrt 89
QUEENS DRIVE	17	.3	1.05		6	6	15	1	Completed
DORSETSHIRE/SION HILLS	2		.2				4		Completed
BUCCAMENT	28	.75	2.50		15	15	35	2	Completed
LAYOU	17		1.50				30		Completed
BARROUALLIE	14		1.50				30		Completed
CHATEAUBELAIR	21	.5	2.00		10	10	30	2	Sched 4 Qrt 89
GEORGETOWN	28	.5	1.50		10	10	20	2	Sched 1 Qrt 90
CANE GARDEN	5		.5	1			10		Sched 1 Qrt 90
SPRING VILLAGE	12	.4	1.05		8	8	13	1	Completed
TROUMACA	7		.5				10	1	Sched 4 Qrt 89
UPPER QUESTELLES	13	.1	.6		2	2	10	1	Sched 4 Qrt 89
LEVEL GARDENS	17	.5			10			2	Sched 4 Qrt 89
RILLAN HILL	8	.75	1.25		15	15	10	3	Completed
TOP CALDER	7	.75	1.00		15	15	5	3	In progress
FAIRBURN PASTURE	5		.3				6	1	In progress
PETIT BORDEL	12	.15	.75		3	3	12	1	In progress
BYRERA HILL	13	.3	1.05		6	6	15	2	Sched 1 Qrt 90
BELAIR	26	.6	2.60		12	12	40	2	Completed
GLEN/CALLIAQUA	30	.5	2.00	1	10	10	30	2	Completed
KINGSTOWN	10	.5						5	In progress
TOTAL	455	10.2	33.05	3	205	181	440	48	

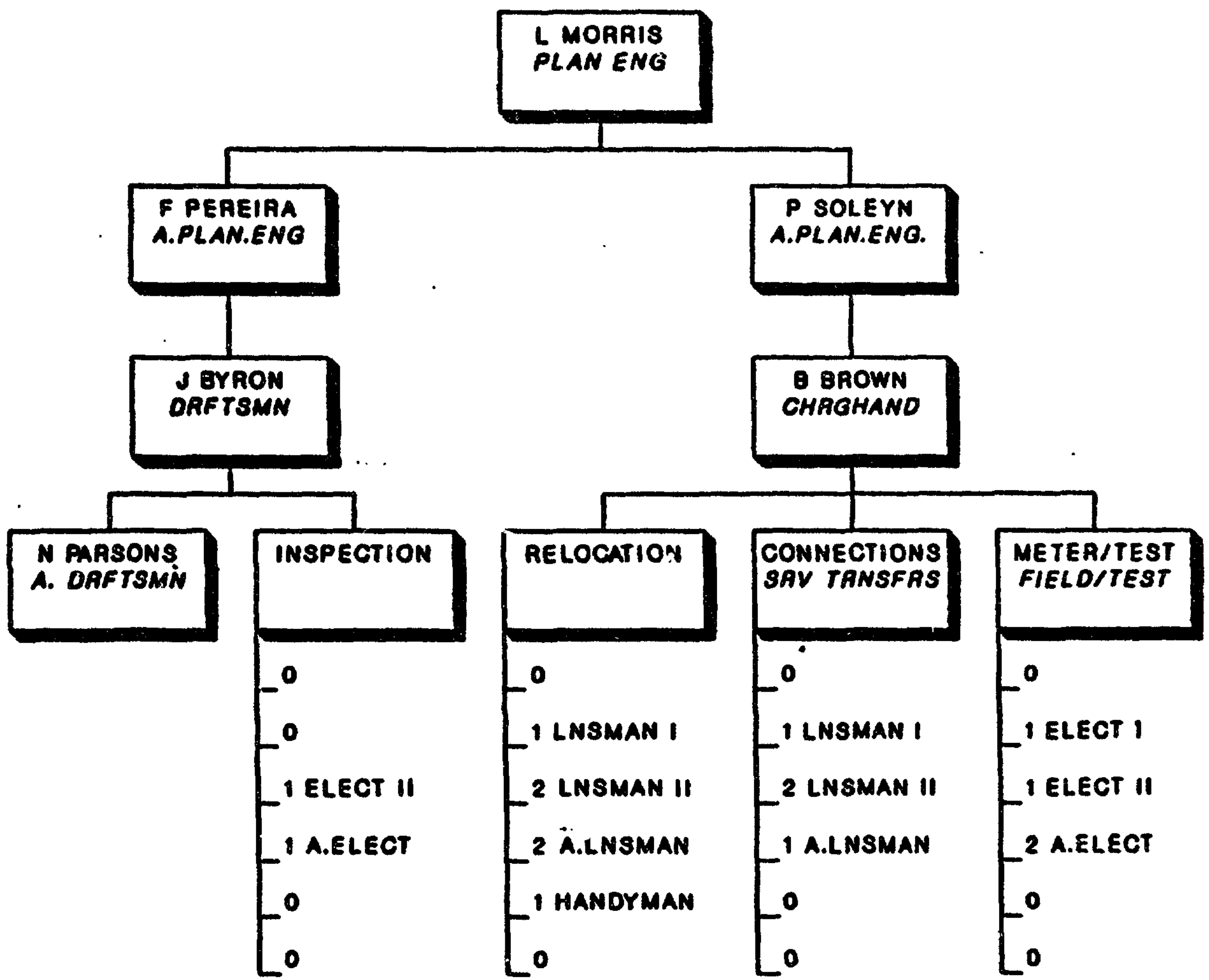
Appendix 14

T&D
SUPERVISORY CHART

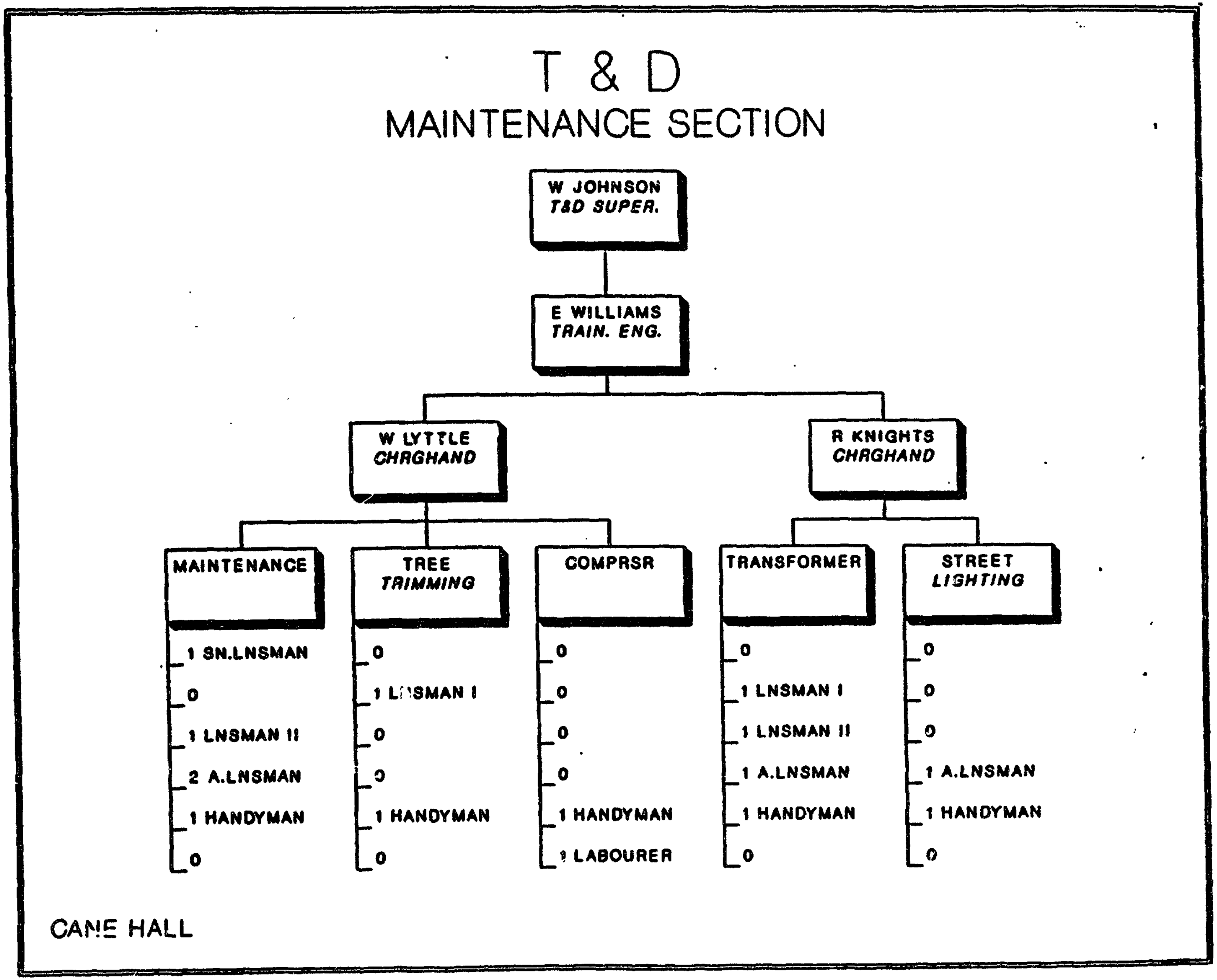


Appendix 15

T & D
PLANNING SECTION

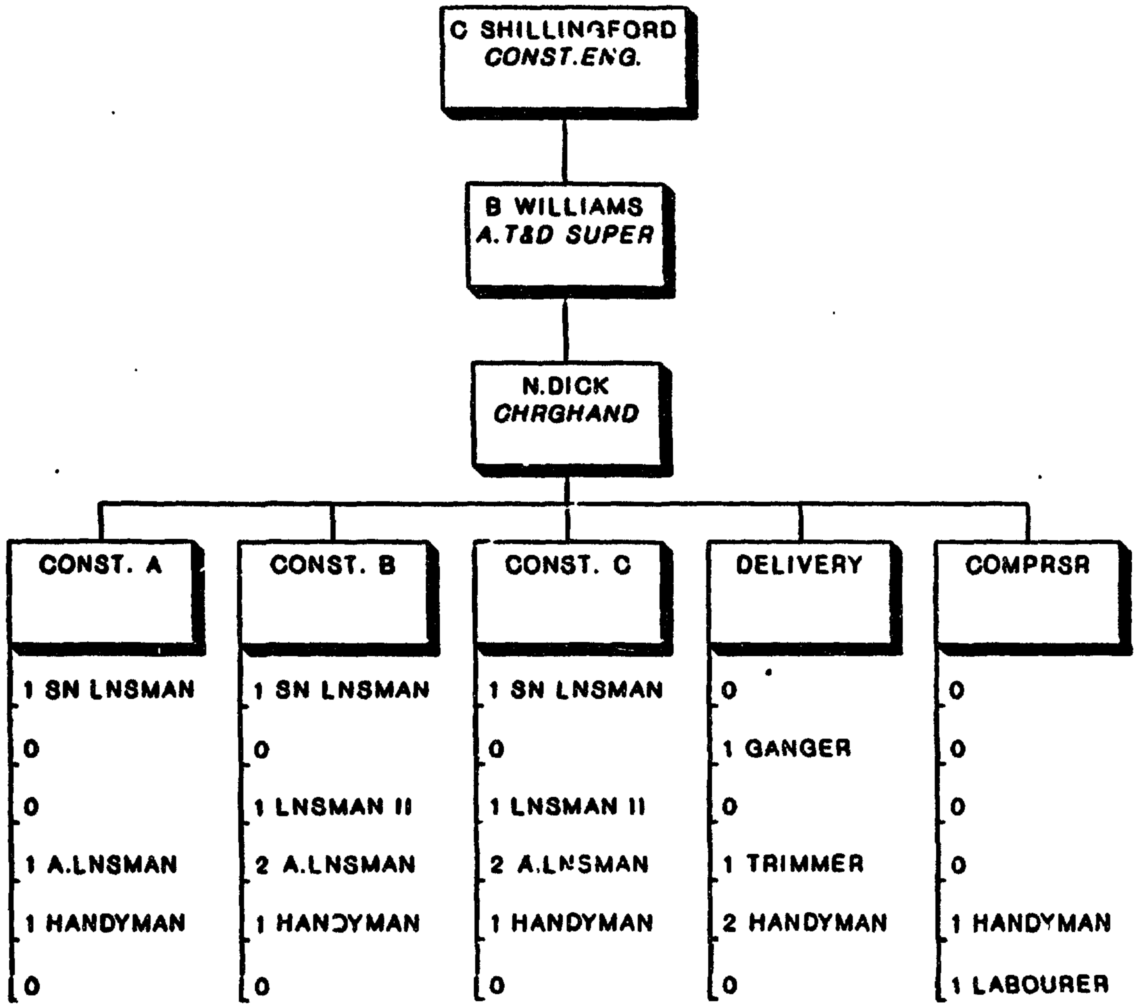


Appendix 16


T & D
MAINTENANCE SECTION
W JOHNSON
T&D SUPER.
E WILLIAMS
TRAIN. ENG.
W LYTTLE
CHRGHAND
R KNIGHTS
CHRGHAND
MAINTENANCE
1 SN.LNSMAN
0
1 LNSMAN II
2 A.LNSMAN
1 HANDYMAN
0
TREE
TRIMMING
0
1 LNSMAN I
0
0
1 HANDYMAN
0
COMPRSR
0
0
0
0
1 HANDYMAN
1 LABOURER
TRANSFORMER
0
1 LNSMAN I
1 LNSMAN II
1 A.LNSMAN
1 HANDYMAN
0
STREET
LIGHTING
0
0
0
1 A.LNSMAN
1 HANDYMAN
0
CANE HALL

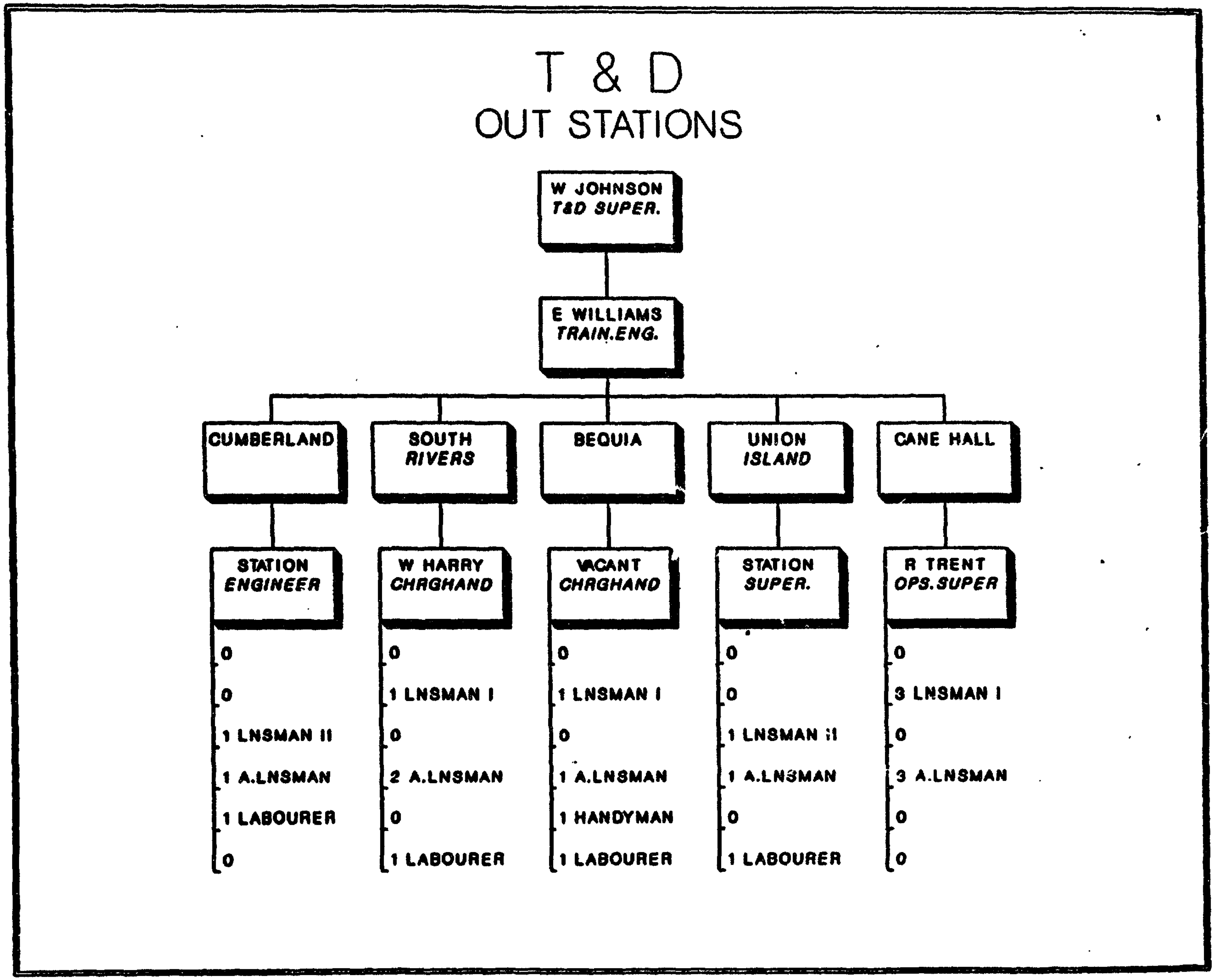
Appendix 17

T & D
CONSTRUCTION SECTION



Appendix 18

Appendix 19


T & D
OUT STATIONS
W JOHNSON
T&D SUPER.
E WILLIAMS
TRAIN.ENG.
CUMBERLAND
SOUTH RIVERS
BEQUIA
UNION ISLAND
CANE HALL
STATION ENGINEER
W HARRY CHRGHAND
VACANT CHRGHAND
STATION SUPER.
R TRENT OPS.SUPER
0
0
1 LNSMAN II
1 A.LNSMAN
1 LABOURER
0
0
1 LNSMAN I
0
2 A.LNSMAN
0
1 LABOURER
0
1 LNSMAN I
0
1 A.LNSMAN
1 HANDYMAN
1 LABOURER
0
0
1 LNSMAN II
1 A.LNSMAN
0
1 LABOURER
0
3 LNSMAN I
0
3 A.LNSMAN
0
0

IN THE HIGH COURT OF JUSTICE
SAINT VINCFNT AND THE GRENADINES
SUIT NO. 184 OF 1983
BETWEEN:

ST. VINCENT ELECTRICITY SERVICES LIMITED	PLAINTIFF
AND	
MORRIS AND COMPANY LIMITED	DEFENDANT

SUIT NO. 186 OF 1983
BETWEEN:

MORRIS AND COMPANY LIMITED	PLAINTIFF
AND	
ST. VINCENT ELECTRICITY SERVICES LIMITED	DEFENDANT

Mr Anthony Crick and Mr Keith Sutherland for St. Vincent Electricity Services Limited (VINLEC).

Mr O.R. Smith Q.C., Mr Dave DaSilva with him for Morris Company Limited.

(December 8, 20, 1988: January 12, 17, 1988 or 1989)

JUDGEMENT

Joseph Carlos

On 4 November 1983 these two matters were by Order of Court consolidated to be heard as one and in them St. Vincent Electricity Services Limited "VINLEC" claims that Morris and Company Limited "MORRIS" owes VINLEC $53,336.70 being $52,811.70 for electricity consumed for the period May 1981 to May 1983 and $525.00 being replacement cost of one meter. Morris alleges that on the 28 June 1983 VINLEC disconnected its electricity supply and thereafter has withheld from him a supply of electricity to its premises. As a result Morris suffered financial loss and damage and continues to dc so and claims:

1. A declaration that VINLEC is not entitled or empowered to disconnect the supply of electricity to the Morris' premises at Bay Street in Kingstown.

2. An injunction to restrain VINLEC ... from disconnecting the electricity supply to Morris' premises and/or in any way from interfering with and/or depriving Morris of a supply of electricity to its premises and/or withholding from Morris a supply of electricity to its premises.

3. An Order that VINLEC do forthwith reconnect the electricity supply to Morris' said premises and cause a supply of electricity to be restored to Morris' said premises.

4. Damages for breach of contract and/or for trespass to goods.

5. Further and other reliefs.

6. Cost

VINLEC admits disconnecting Morris' supply of electricity but asserts that it did so by virtue of the powers conferred on it in Act No. 14 of 1973, Morris having refused to pay the sum of $52,811.70 in respect of electricity consumed by Morris during period May 1981 to May 1983 as per bill submitted by VINLEC to Morris on 14 June 1983. VINLEC also alleges that between 26 May 1983 and 27 May 1983 VINLEC discovered that the meters on Morris' premises were tampered with so as to prevent them from correctly registering the quantity of electricity consumed.

Morris, in what can be described as a bare denial defence, simply denies owing VINLEC the sum of $53,336.70 or any sum at all.

With leave of the Court granted to VINLEC during the hearing of this matter, VINLEC amended its statement for claim in Suit No. 184 of 1983? to specifically plead the fraud alleged by them in their defence to Morris Suit No. 186/1983 i.e. the allegation that Morris tampered with VINLEC's meters thereby preventing them from accurately registering the electricity consumed by Morris. To this Morris filed an amended defence denying that it fraudulently consumed any electricity generated by VINLEC. I now give my reasons for granting this amendment.

The application was by VINLEC to amend its Statement of Claim in Suit No.184/1983 to include a plea of fraud against Morris: This appliction was made after the case for VINLEC was closed and as the witness Dick was about to continue his evidence in chief after the adjourned hearing. Learned Q.C. for Morris objected to the amendment being allowed on the grounds that what we were dealing with was a consolidated action and that what was now being raised could not have been said not to have been apparent to VINLEC before this time.

Mr. Smith contended that the introduction of a charge of fraud at the stage was too late. Mr Crick in reply argued that the pleadings, especially the defence filed by VINLEC in Morris' Suit No. 186.1983, the affidavit of John Hazell, and indeed, the evidence of John Hazell relate to an issue of the fraudulent tampering by Morris of VINLEC's meters thereby preventing them from correctly registering the quantity of electricity consumed by Morris. He contended that the issue of fraud was the real controversy between the parties.

Having perused the pleadings in this consolidated matter and, bearing in mind the affidavit of John Hazell and his evidence led in this Court, I agreed with the contention of Mr Crick that the real controversy between the parties is whether or not Morris tampered with the meters as alleged by VINLEC for the purpose of defrauding VINLEC. To my mind, this was the basis for the respective claims of both parties in their different suits, this having been disclosed in the pleadings since VINLEC filed their defence in Suit No. 186/1983 in September of 1983 or for that matter since John Hazell swore to an affidavit in that suit in July 1983. My view is that what VINLEC now seeks, is merely a tidying up of the pleadings to include therein the specific plea of fraud, such an allegation of necessity requiring to be specifically pleaded (See 018 R 8 of the Rules of the Supreme Court (Revision) 1970. Having so found granted the application of VINLEC for the amendment as prayed for. I also ordered that VINLEC pay Morris all costs thrown away as a result of the amendment. And, upon the application of Mr Smith, I adjourned the matter to give Morris an opportunity to file an amended defence if necessary within 14 days from the date of that order.

In granting that application the Court had foremost in its mind the general principles for the grant of leave to amend as is set in the Supreme Court Practice of England (1985) Vol. 1 Page 340 at para. 20/5 - 8/6. This Court recognised the guiding principle of Cardinal inportance on the question of amendment that generally speaking all such amendments ought to be made for the purpose of detemining the real question of controversy between the parties to any proceedings or of correcting any defects or error in any proceedings. See Baker Ltd. V. Medway Building and Supplies Ltd. (1958) 1 WLR 1216.

In Shoe Manufacturing Co. V. Vultrain (1896) 1 Ch 108 at P112 A. L. Smith L.J. expressed "emphatic agreement" with Bowen L.J.? in Cropper V. Smith (1883) 26 Ch. D 700 when he at Pp 710-711 said:

> "It is a well established principal that the object of the Court is to decide the rights of the parties and not to punish them for mistakes they make in the conduct of their cases by deciding otherwise than in accordance with their rights ... I know of no kind of error or mistake, which if not fraudulent or intended to over reach, the Court ought not to correct if it can be done without justice to the other party. Courts do not exist for the sake of discipline but for the sake of deciding matters in controversy and I do not regard such amendment as a matter of favour or grace. It seems to me that as soon as it appears that the way in which a party has framed his case will not lead to a decision of the real matter in controversy, it is as much a matter of right on his part to have it corrected if it can be done without injustice, as anything else in the case is a matter of right."

I can find nothing in the proceedings before me to suggest that the introduction of this plea at this late stage of the proceedings is fraudulent or intended by VINLEC to overreach. It appears to me to be a blunder on the part of the Solicitors for VINLEC, a blunder which was neither fraudulent nor intended to overreach. As I said earlier, it appears to me to be a mere tidying up of VINLEC's pleadings and I do not see any injustice to Morris in granting this amendment. Indeed, from all that I've stated above I am satisfied that justice required that this amendment be granted. The entire trial up to the time of this application went along the line of this plea of fraud. In Atkinson V. Fitzwalter and others (1987) 1ALL BR 483 it was held in the Court of Appeal of England that the general principle to be applied in considering an amedment, however late, was that it should be allowed if justice required it, provided the other party could be monetarily compensated for any inconvenience, and the fact that the amendment alleged fraud was not of itself reason to refuse to allow it to be made.

I am of the view that the amendment merely seeks to clarify the existing issues in dispute and does not raise any new issue for the first time. I therefore do not see that the allowing of this amendment will impose any new issue for the first time. I therefore do not see that the allowing of this amendment will impose any strain or anxiety on Morris. We are not dealing here with personal litigants but with business corporations and Morris is not being called upon by this amendment to face any new issue: (See Ketteman VHansel Properties Ltd. (1988) 1 ALL BR 38).

For the above reasons, in the exercise of this Courts judicial discretion, a discretion guided by my assessment of where justice lies, I granted the amendment in the terms as aforesaid.

I would now proceed to deal with the substantive matter.

John Hazell, a qualified engineer since 1971 and Manager of VINLEC since August 1981, testified on behalf of VINLEC. He was cross-examined at length in a searching cross examination by Q.C. Mr Smith and having seen and heard him I can find nothing to fault his testimony and I accept it on a preponderance of probabilities and being true. From his evidence I make these findings of facts.

VINLEC is a private company incorporated by the Electricity Supply Act No. 14 of 1973. Its principal function is to supply electricity to consumers in the State of St. Vincent and the Grenadines. Morris is one of VINLEC's consumers. Morris operates the business of a bakery, supermarket, grocery, hardware and a lumber yard. The supply of electricity to those different businesses is by VINLEC and there are three meters installed in the building at Bay Street.

Kingstown, for the purpose of registering the amount of electricity consumed by Morris, upon a reading of which by VINLEC. Morris will be required by VINLEC to pay for such consumption.

In the year 1983 VINLEC realised that for several years they were experiencing a loss of more than 10% between the power generated by its utility and sent out to consumers and quantities of power recorded and billed as having been used by these consumers. This was abnormal so they undertook an investigation as to the source of these losses with a view to reducing them to accepted levels. As a rule of thumb such losses should occur in two areas. Technical losses ocurring in transformers, transmission lines and distribution systems and non-technical losses relating to deficiencies or inaccuracies in metering or diversion of power from being registered on meters.

The purpose of the investigation was to decide what specific measures VINLEC should take to generally reduce non-technical losses. The investigation was carried out by a consultant together with staff from VINLEC, a metering specialist from Barbados and certain technical and Government Staff.

In the process of the investigation of non-technical losses, a number of accounts were chosen at random for investigation as to whether the metering of electricity used by these accounts were accurate or if not accurate to what extent. One of these accounts was Morris'.

On 26 May 1983 the investigation team left for Morris to look at this particular account and late that afternoon the team made a report to John Hazel. As a result Hazell went to Morris' premises where he met the Consultant, the metering specialist and the other members of the investigating team.

On an interior wall in the premises inside the building adjacent to an enclosed area used as a Supervisor's Office, Hazell saw the three meters. The meters were opened in his presence and he saw two pieces of copper wires which were foreign to the construction of the meters inserted in two of the meters, in a manner which would prevent the full electrical energy entering the premises from being registered on those meters. In his presence, the copper wires were taken out of the meters and handed to him and he produced them in evidence at this hearing. Hazell indicated his find to Pat Velox whom he was told was in charge.

The witness Hazell then gave a physical demonstration to the Court with the aid of an old meter as to how the inspection of such a piece of copper wire in a meter can prevent the meter from registering the full amount of electricity consumed by the consumer. Based on this witness' expertise, this Court accepts his evidence and finds as a fact that current can be diverted from being registered in the meter by this process.

I also find as a fact that the pieces of copper wire produced in evidence by the witness Hazell were found in the meters by VINLEC in the circumstances as decribed by Hazell. I also find as a fact that the meters in which these wires were found were located on Morris premises with Morris having effective custody or control of them. The evidence of Alfred Dick and Frederick Richards, the Assistant Manager and Supervisor respectively of Morris, adequately supports this finding of mine. These witnesses testify that these meters were located in an office which they occupy in the hardware section of Morris, that the meters are at eye level with Dick when standing and that no one can enter that office without their permission. Also that only VINLEC's employees would go to those meters and that was for the purpose of reading

Having made these findings of facts, I hold as a matter of law that VINLEC has satisfied this Court prima facie, that Morris had without legal right, wilfully prevented the meters from duly registering the full quantity of electricity supplied by VINLEC. To support this finding of mine I refer to the Electricity Supply Act 1973 (the Act) at S 19(3) which states as follows:

> "If upon any premises or land in the occupation of a consumer having effective custody or control of a meter or installtion there is connected or adjacent to any electric line or meter any wire or device capable of wrongfully abstracting, diverting, consuming or using electricity or of preventing any meter from correctly registering any quantity of electricity supply by the Company, the existence of such wire or device shall be accepted by a Court as prima facie evidence that such consumer has without legal right abstracted or diverted electricity or (as the case may be) has without legal right wilfully prevented a meter from duly registering any quantity of electricity supplied by the Company."

VINLEC having made out this prima facie case against Morris, I do not agree with the submission of Q.C. Smith that it is not for Morris to prove that they did not put the wires there. My view is that the prima facie evidence having been produced by VINLEC a burden then lay on the shoulders of Morris to account for the presence of the wires in the meters. I have looked in vain throughout the entire evidence to see if this burden was discharged by Morris on a balance of probabilities and I can find not a scintilla of evidence in this regard. All I can find are veiled insinuations against VINLEC without any proof, by Mr Smith during his cross-examination of VINLEC's Manager, Mr John Hazell. Indeed, I find it passing strange that Pat Velox, a Director of Morris would remain silent and show disinterest when confronted with the evidence of the wires at the very time when they were found in the meters. One reasonably would have expected some form of protest or some show of indignation from her. But her evidence is that she remained silent and showed disinterest.

Having regard to these observations I hold as a matter of fact that Morris has not discharged the burden placed on them to negative the prima facie evidence against them on a balance of probabilities.

I therefore find as a fact that Morris, by means of copper wires inserted in VINLEC's meters on Morris' premises, had without legal right wilfully prevented the meters form duly registering the full quantity of electricity supplied to them by VINLEC.

The next issue to be decided is what was the loss suffered by VINLEC as a result of tampering with the meters by Morris. Here again I accept the evidence of John Hazell that such a loss can, on a balance of probabilities, be quantified at $52,811.70. His evidence on this aspect which I accept is that VINLEC looked at Morris' pattern of consumption from their records and concluded that the diversion started from May 1981. These records have been produced in Court and, in my view, they support the conclusion of the witness and I so find as a fact. They were admitted in evidence by consent and the accuracy of their contents was not challenged in cross-examination or otherwise. I accept Hazell's evidence when he said VINLEC examined Morris' records prior to May 1981 and their assessment was that for six months or so preceding May 1981, Morris' average consumption of VINLEC's electricity was approximately 11,000 units per month whereas, its average consumption following May 1981 up to the time the diversion was discovered was of the order of 6000 units per month. The records of VINLEC produced in Court support this examination of VINLEC and, from this witness' evidence and the documentary evidence, I accept and find as a fact, that the loss suffered by VINLEC as a result of this diversion of current was in the vicinity of some 5,000 units per month from May 1981 to May 1983 when the diversion was discovered which, as above stated, I would quantify as $52,811.70. In arriving at this conclusion I take into consideration the evidence of all the witnesses who testified in this matter especially the evidence concerning the different appliances that needed to be served by electricity and the evidence of Dick that with twice the amount of appliances now in operation, the average consumption of electricity is in the vicinity of around 22,000 units per month.

Having quantified the loss at $52,811.70, I find as a fact that Morris owed that sum of money to VINLEC. I find as a fact that VINLEC informed Morris of this debt by letter dated 14 June 1983 and requested payment by 27 June 1983. VINLEC, receiving no response from Morris by way of payment or dispute of the debt or otherwise within the prescribed time, they disconnected Morris' electricity supply. VINLEC's Manager Hazell was taken to task by Mr Smith for disconnecting Morris within two weeks of Morris receiving the demand letter when it is the normal practice to allow at least 30 days before disconnection. I accept Hazell's explanation for this when he said that 30 days was only given where there was no indi-cation of irregularity.

The next issue to be decided in this consolidated matter is whether such a disconnection by VINLEC was lawful or not. In this regard I refer to Ss 19(2) and 22 of Act: Sec 19(2) states as follows:

> "If any person without legal thought unlawfully disconnects, damages or removes any electricity line, meter switch, fuse or other works or apparatus belonging to the Company or alters the index of any meter belonging to the Company, or otherwise prevents any such meter from correctly registering any quantity of electricity supplied by the Company, such person shall be guilty of an offence and for every such offence he shall be liable on summary conviction to a penalty not exceeding one hundred and fifty dollars for the first offence and not exceeding two hundred and fifty dollars for any such subsequent offence, and without prejudice to the foregoing, the Company may recover from such person the amount of any damage by it sustained and may also (notwithstanding any agreement or contract previously existing) discontinue any supply of electricity to such person."

And S 22 states as follows:

> "If any consumer shall be in default with any payment due by him to the Company in respect of electricity the Company (without prejudice to any other remedy available to it) shall be at liberty to discontinue the supply to electricity to such consumer until such time as such payment together with the Company's reasonable charges for the reconnection of such Consumer's electricity services have been paid."

I interpret these two provisions of the Law in the Act to mean that VINLEC can discontinue electricity supply to a consumer if the consumer has been in default of payment of his electricity bills or if such consumer has been found to have tampered with the electricity meter. VINLEC's Manager, John Hazell's evidence seems to suggest that VINLEC disconnected Morris under S 22 of the Act i.e. for Morris' default in making the payment. To my mind, having regard to my aforementioned findings, VINLEC would have been justified in disconnecting Morris on either or both of the ground aforementioned. I find no merit in the submission of Mr. Smith that VINLEC could not have disconnected Morris under S 19(2) because when the disconnection took place new meters which were not tampered with were already in place. The evidence shows that after the dicovery of the diversion negotiations started and were continuing between the parties and I cannot see how the placing of new meters on the premises by VINLEC would have taken away their right in law to disconnect for the breach by Morris of S 19(2) of the Act. There is no pleading by Morris or acquiesence or waiver by VINLEC of Morris' illegal act, and indeed, the evidence shows outrage on the part of VINLEC.

I also do not agree with the submission of Mr Smith that disconnection under S22 would also have been unlawful. Learned Queen's Counsel gave as his reason for so submitting that the debt of $52,811.70 was a disputed debt. I agree with his submission that a disputed sum cannot be a payment due but, I find as a matter of law that as a result of the non response by Morris to VINLEC's demand for payment, the debt could not have been said to be disputed, and the disconnection took place in these circumstances. Also, having regard to the circumstance of illegality or irregularity which this Court finds in Morris, I am satisfied that the two weeks given by VINLEC for Morris to pay the debt was an extremely generous act on VINLEC's part. To my mind, the debt only became disputed after the disconnection took place and then the parties came to a "without prejudice" agreement whereby upon Morris paying VINLEC $19,000 the electricity was restored as at July 1983.

Having made these findings I find the disconnection by VINLEC of Morris' electricity to be lawful and in accordance with the provisions of the Act. Taking this matter in its totality and on a preponderance of probabilities I find VINLEC's allegation of fraud on the part of Morris proved to the hilt.

In these circumstances, and, having found legal justification for VINLEC's disconnection of Morris' electricity I can find no merit in Morris' Suit No. 186 of 1983 against VINLEC and I order that it stand dismissed with costs to VINLEC to be taxed if not agreed and that Judgement be entered for VINLEC against Morris in Suit No. 184 of 1983 for $52,811.70 being payment due for electricity consumed by Morris and not paid for and $525.00: being the cost of one meter which I find VINLEC had to replace as a result of the unlawful act of Morris. VINLEC will have the costs of the action to be taxed if not agreed.

I therefore make the order that Judgement be entered for VINLEC in the consolidated matter for $53,336.70 less the sum of $19,000.00 already paid with cost to be taxed if not agreed.

SUPREME COURT JUDGE

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAM

Activities Completed

Country	Project	Date	Number
ENERGY EFFICIENCY AND STRATEGY			
Africa			
Regional	The Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development	3/90	112/90
	Participants' Reports - Regional Power Seminar on Reducing Electric System Losses in Africa	8/88	087/88
Bangladesh	Power System Efficiency Study	2/85	031/85
Bolivia	La Paz Private Power Technical Assistance	2/90	111/90
Botswana	Pump Electrification Prefeasibility Study	1/86	047/86
	Review of Electricity Service Connection Policy	7/87	071/87
	Tuli Block Farms Electrification Prefeasibility Study	7/87	072/87
Burkina	Technical Assistance Program	3/86	052/86
Burundi	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987)	5/85	036/85
	Review of Petroleum Import and Distribution Arrangements	1/84	012/84
Burundi/Rwanda/Zaire	(EGL Report)		
	Evaluation de l'Energie des Pays des Grands Lacs	2/89	098/89
Congo	Power Development Study	5/90	106/90
Costa Rica	Recommended Technical Assistance Projects	11/84	027/84
Ethiopia	Power System Efficiency Study	10/85	045/85
The Gambia	Petroleum Supply Management Assistance	4/85	035/85
Ghana	Energy Rationalization in the Industrial Sector of Ghana	6/88	084/88
Guinea-Bissau	Recommended Technical Assistance Projects in the Electric Power Sector	4/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors	2/90	100/90
Indonesia	Energy Efficiency Improvement in the Brick, Tile and Lime Industries on Java	4/87	067/87
	Power Generation Efficiency Study	2/86	050/86
	Diesel Generation Efficiency Improvement Study	12/88	095/88
Jamaica	Petroleum Procurement, Refining, and Distribution	11/86	061/86
Kenya	Power System Efficiency Report	3/84	014/84
Liberia	Power System Efficiency Study	12/87	081/87
	Recommended Technical Assistance Projects	6/85	038/85
Madagascar	Power System Efficiency Study	12/87	075/87
Malaysia	Sabah Power System Efficiency Study	3/87	068/87
Mauritius	Power System Efficiency Study	5/87	070/87
Mozambique	Household Electricity Utilization Study	5/90	113/90
Panama	Power System Loss Reduction Study	6/83	004/83
Papua New Guinea	Energy Sector Institutional Review: Proposals for Strengthening the Department of Minerals and Energy	10/84	023/84
	Power Tariff Study	10/84	024/84

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAM

Activities Completed

Country	Project	Date	Number
ENERGY EFFICIENCY AND STRATEGY (Continued)			
Senegal	Assistance Given for Preparation of Documents for Energy Sector Donors' Meeting	4/86	056/86
Seychelles	Electric Power System Efficiency Study	8/84	021/84
Sri Lanka	Power System Loss Reduction Study	7/83	007/83
Syria	Electric Power Efficiency Study	9/88	089/88
	Energy Efficiency in the Cement Industry	7/89	099/89
Syria	Energy Efficiency Improvement in the Fertilizer Sector	6/90	115/90
Sudan	Power System Efficiency Study Management	6/84	018/84
	Assistance to the Ministry of Energy and Mining	5/83	003/83
Togo	Power System Efficiency Study	12/87	078/87
Tunisia	Interfuel Substitution Study	5/90	114/90
Uganda	Energy Efficiency in Tobacco Curing Industry	2/86	049/86
	Institutional Strengthening in the Energy Sector	1/85	029/85
	Power System Efficiency Study	12/88	092/88
Zambia	Energy Sector Institutional Review	11/86	060/86
	Energy Sector Strategy	12/88	094/88
	Power System Efficiency Study	12/88	093/88
Zimbabwe	Petroleum Supply Management	2/90	109/90
	Power Sector Management Assistance Project: Background Objectives, and Work Plan	4/85	034/85
	Power System Loss Reduction Study	6/83	005/83
HOUSEHOLD, RURAL, AND RENEWABLE ENERGY			
Burundi	Peat Utilization Project	11/85	046/85
	Improved Charcoal Cookstove Strategy	9/85	042/85
Cape Verde	Household Energy Strategy Study	2/90	110/90
China	Country-Level Rural Energy Assessments: A Joint Study of ESMAP and Chinese Experts	5/89	101/89
	Fuelwood Development Conservation Project	12/89	105/89
Costa Rica	Forest Residues Utilization Study, Volumes I & II	2/90	108/90
Côte d'Ivoire	Improved Biomass Utilization--Pilot Projects Using Agro-Industrial Residues	4/87	069/87
Ethiopia	Agricultural Residue Briquetting: Pilot Project	12/86	062/86
	Bagasse Study	12/86	063/86
The Gambia	Solar Water Heating Retrofit Project	2/85	030/85
	Solar Photovoltaic Applications	3/85	032/85
Ghana	Sawmill Residues Utilization Study, Vol. I & II	10/88	074/87
Global	Proceedings of the ESMAP Eastern and Southern Africa Household Energy Planning Seminar	6/88	085/88
India	Opportunities for Commercialization of Non-Conventional Energy Systems	11/88	091/88
Indonesia	Urban Household Energy Strategy Study	2/90	107/90
Jamaica	FIDCO Sawmill Residues Utilization Study	9/88	088/88
	Charcoal Production Project	9/88	090/88

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAM

Activities Completed

Country	Project	Date	Number
HOUSEHOLD, RURAL, AND RENEWABLE ENERGY (Continued)			
Kenya	Solar Water Heating Study	2/87	066/87
	Urban Woodfuel Development	10/87	076/87
Malawi	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry	11/83	009/83
Mauritania	Elements of a Household Energy Strategy	7/90	123/90
Mauritius	Bagasse Power Potential	10/87	077/87
Niger	Household Energy Conservation and Substitution	12/87	082/87
	Improved Stoves Project	12/87	080/87
Pakistan	Assessment of Photovoltaic Programs, Applications and Markets	10/89	103/89
Peru	Proposal for a Stove Dissemination Program in the Sierra	2/87	064/87
Rwanda	Improved Charcoal Cookstove Strategy	8/86	059/86
	Improved Charcoal Production Techniques	2/87	065/87
Senegal	Industrial Energy Conservation Project	6/85	037/85
	Urban Household Energy Strategy	2/89	096/89
Sri Lanka	Industrial Energy Conservation: Feasibility Studies for Selected Industries	3/86	054/86
Sudan	Wood Energy/Forestry Project	4/88	073/88
Tanzania	Woodfuel/Forestry Project	8/88	086/88
	Small-Holder Tobacco Curing Efficiency Project	5/89	102/89
Thailand	Accelerated Dissemination of Improved Stoves and Charcoal Kilns	9/87	079/87
	Rural Energy Issues and Options	9/85	044/85
	Northeast Region Village Forestry and Woodfuel Pre-Investment Study	2/88	083/88
Togo	Wood Recovery in the Nangbeto Lake	4/86	055/86
Uganda	Fuelwood/Forestry Feasibility Study	3/86	053/86
	Energy Efficiency Improvement in the Brick and Tile Industry	2/89	097/89
Zambia	Urban Household Energy Strategy Study	8/90	121/90
Zimbabwe	Charcoal Utilization Prefeasibility Study	6/90	119/90