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A New Spreadsheet Model for Comprehensive Power Systems Planning in Developing Countries

Working Paper #2

Progress Report

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Preface

This paper describes a new model for planning and development of supply-constrained power systems in developing countries, work sponsored by the Office of Energy of USAID. It is being circulated at this time only for review and comment, and is not for citation or attribution.

1. Background

The 1990's will prove to be a period of profound change for electric utilities in developing countries as increasing problems of capital mobilization, financial viability, and a deterioration in quality of service force a reappraisal of traditional approaches to power sector planning and development. Indeed, the changes in the international financial environment upon which electric utilities in developing countries have long been dependent for project loans will necessarily force a fundamental reappraisal of long-established practices and priorities.

Electric utilities in most developing countries are supply-constrained: that is, their load growth tends to be constrained only by their ability to expand the network and augment generation capacity to accommodate new customers. With large segments of the population typically still without electricity the political and social pressures for system expansion are strong, making load growth projections subject to great controversy. Moreover, it is clear that the state of repair and maintenance of both the distribution system and the generating plant in many countries is deficient, resulting in a poor quality service to the consumer and creating an operational environment in which management attention is focused on short-term remedial measures, often to the detriment of sound long-term planning.

These problems are of course well recognized by the donor community. The March 1988 USAID report on Power Shortages in Developing Countries, prepared in response to a Congressional Request, finds that in over half of all AID assisted countries, power shortfalls constitute a serious constraint to development. The report notes that electric utilities in developing countries have traditionally attempted to solve their electricity delivery problems by expanding central station generation capacity, an approach that had led to larger and larger unit sizes justified on the basis of scale economies. However, the increasing financial and environmental costs of this approach are no longer sustainable, and the AID report points to a number of options, of which an improved investment planning approach, the focus of this proposed project, is a most important component.

A recent World Bank study[1], which reviewed some 300 Power projects financed by the Bank and the IDA between 1965 and 1983, makes many of the same

1 "A Review of World Bank Lending for Electric Power", Energy Series Paper #2, March 1988.

points. The study established declining trends in key financial indicators (such as rate of return on assets and the self-financing ratio) and quality of service in many countries assisted by the Bank. It recommended a number of specific steps to improve productive and allocative efficiency: increasing incentives for enhanced utility efficiency, strengthening of power-energy-macroeconomic linkages, improving investment planning to achieve a better balance between generation and distribution, and giving greater emphasis to rehabilitation and maintenance.

In response to the need for new approaches to power sector planning in developing countries, the Office of Energy of USAID is supporting a number of new initiatives in the area of "comprehensive power sector planning".[2] The basic idea is to develop an analytical approach to power sector planning that provides a symmetrical and balanced treatment of all options related to the provision of electricity. The fundamental premise of this effort is that the main objective should be the most efficient allocation of resources across the entire power sector, to include new supply, rehabilitation, loss reduction, transmission, distribution, end-use efficiency and demand management. In short, the goal is to maximize the benefits of limited investment resources. This is fundamentally different from the current modelling emphasis on least cost expansion of supply to meet given levels of electricity demand.

This Working Paper describes a new spreadsheet model for power sector planning called ELECTROPLAN that is currently under development and testing. Its main objective is to satisfy the requirements of this new planning environment.

2 The choice of terminology is deliberate, given the proliferation of terms that have come into use over the past few years. We prefer not to use the terms "least-cost planning", or "integrated value based planning" because of their association with specific institutional initiatives or advocates in the United States (the latter term, for example, corresponds to a program initiative by EPRI). In any event, the word "comprehensive" best characterizes the objective that the planning process should include not just the expansion of the central grid, but incorporate all options for promoting development by the provision of electricity. For a good discussion of the history of all of these concepts, see "Moving Toward Integrated Resource Planning: Understanding the Theory and Practice of Least Cost Planning and Demand Side Management", EPRI Report EM-5065, Feb. 1987.

2. Design Criteria for ELECTROPLAN

It is useful to begin with a brief review of the role of models in current developing country practice; we characterize here the situation in the typical small to medium sized developing country.[3] As in the case of energy planning in general, a hierarchic process best characterizes the relationship between the different levels of planning, the models used at each level, and the institutional arrangements.

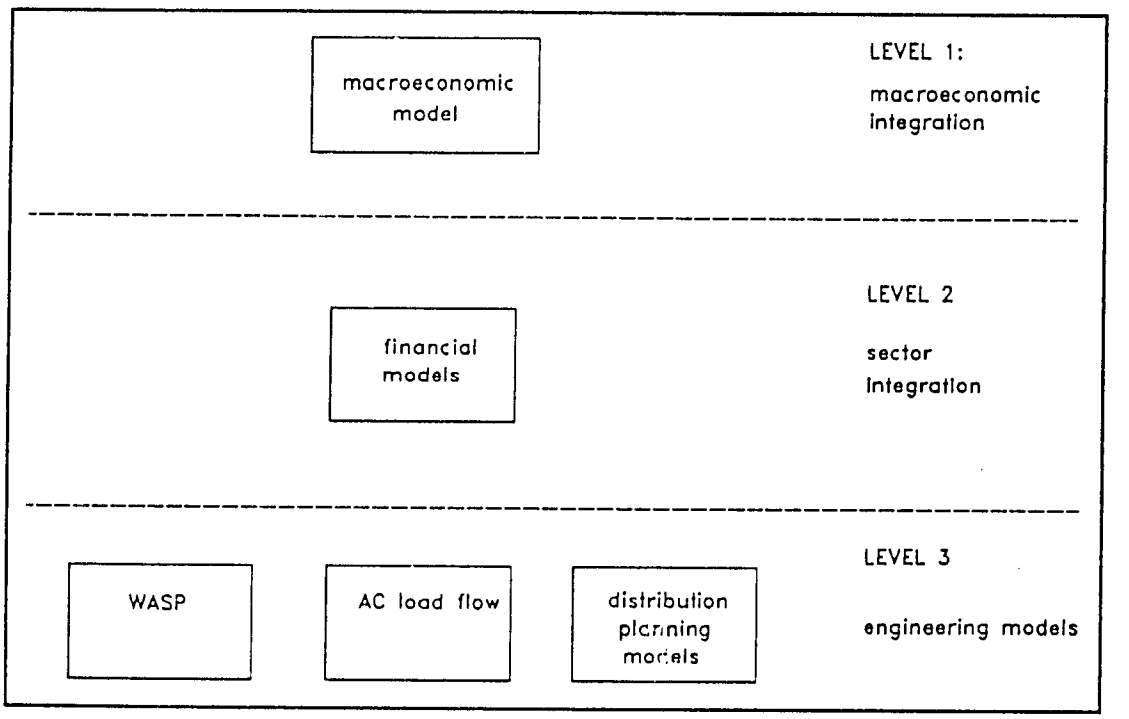

Figure 1: The planning hierarchy

3 Obviously the larger countries have a much more complex structure, both institutionally as well as technically. What follows as a general characterization of developing country electric sector planning is applicable to most countries in Africa, the Caribbean, and the small countries of Asia: it specifically excludes such countries as India, China and Brazil!

The lowest level of the hierarchy corresponds to the technical departments of the typical electric utility (See Figure 1: level 3). The generation department runs WASP[4], the transmission department runs AC load flow models to develop transmission plans, and so on.

The dominant institution at the sectoral level (level 2) is typically the finance department of the utility, whose main modelling tool is the ubiquitous LOTUS financial model. Necessary technical assumptions about demand, fuelcosts and the like are passed up periodically from the technical departments, usually in manually prepared memoranda, only rarely as spreadsheets. This level is the main point of continuing interaction with potential donors. who often have parallel financial models run by their own staff.

Formal Macroeconomic models, if they exist at all, are typically run by Ministries of Planning, again with modelling counterparts in donor agencies (such as the country operations departments of the World Bank). Direct integration of the macroeconomic model with demand projections or with utility financial models is rare, despite the fact that the electric sector often accounts for major shares of public investment. In general the flow of information is from utility to the macroeconomic planning body, and typically takes the form of schedules of investment and financing requirements.

It is not unexpected that such an essentially uncoordinated system of models leads to often inconsistent results, and to plans that cannot be implemented. From a modelling standpoint perhaps the most serious shortcoming is the fact that sensitivity analysis is almost impossible, since so many disparate models are required. This in turn has inhibited the development of a satisfactory approach to the analysis of the uncertainty.

In order to remedy these basic problems, our main objective is to develop a comprehensive model of power sector development at the sectoral and macroeconomic levels of the modelling hierarchy (i.e. at levels 1 and 2 of Figure 1). The other major design criteria for the ELECTROPLAN model include:

1. A balance in the level of detail for the individual submodels. For example, it makes no sense to incorporate extremely sophisticated

4 One of the most interesting questions is why generation expansion optimization models have been so extensively used in developing countries, when they have been so conspicuously absent from United States practice. This is explored further in Annex I.

generation expansion optimization procedures if the representation of the distribution system is captured by a single number for aggregate losses, or if "demand" is represented by an annual growth rate.

2. All of the central components of the model should be contained in a single LOTUS 1-2-3 spreadsheet, an approach made possible by the use of extended memory and the computational power of the current generation of microcomputers based on microprocessors running at 20Mhz and higher. By putting all of the key components into a single spreadsheet sensitivity analysis of the entire system to all of the key uncertainties is made very easy.[5]

3. To the extent possible the model should build on prior work. In fact a number of the building blocks of this system have been adapted from existing models and from related projects. The financial model and its interfaces have been adapted from a model developed by a joint World Bank-USAID study for Morocco[6]. The technical representation of utility generation expansion and dispatch is based on the RESGEN model that has been used in many developing countries.[7] The macroeconomic accounting framework is adapted from a spreadsheet model developed to analyze the impacts of the Sri Lanka National Energy Strategy. And the technical representation of the distribution system is based in part on World Bank studies in Costa Rica and the Punjab, and the recent USAID study of rural electrification in Pakistan.[8]

A rather obvious question at this point is the degree to which one of the electric sector planning models developed in the United States (or indeed others drawn

5 Now that Version 3.0 is available (July 1989), it is no longer necessary to have all of the model components in a single spreadsheet since the new version permits dynamic linkages to multiple memory resident spreadsheets. We are currently in the process of conversion from LOTUS 2.01 to 3.0.

6 See "An Approach to Energy Price and Tax Reform" World Bank Report #7751-MOR, Industry and Energy Operations Division, Mahgreb Department, April 1989.

7 Although RESGEN has been used in a number of countries for general energy planning purposes, the most sophisticated version for the electric sector is that developed for PAKISTAN, which incorporates a monthly load dispatching to calculate fuel consumption and fuelcosts, and a fully dynamic investment planning module that can be linked to WASP runs.

8 Rural Electrification Master Plan Revision, Report by DeLucia and Associates Inc to the Government of Pakistan and USAID, July 1988.

from European practice) might be adapted to developing country use. The most important of these are reviewed in a separate working paper[9]. The main conclusions of that review can be summarized as follows:

1. Many of the important EPRI models are FORTRAN models, and micro-computer versions are not available for all of them. As such the ability to customize the models, in particular their financial modules, is severely limited: in most cases the level of detail provided is quite rudimentary, and is not sufficient to meet the financial modelling requirements of the International Financial Institutions. In any event, such fine detail as is provided is geared toward the specific regulatory and capital market environment of the United States, which has a rather different emphasis to the constraints imposed by lending institutions on developing country utilities.

2. Even though the FORTRAN code in the EPRI models is well documented[10], making modifications not impossible, we view the spreadsheet format as essential given the diversity of developing country situations. A better starting point for the financial representation, therefore, is the sort of LOTUS 1-2-3 model used by the operational divisions of the International Financial Institutions (IFIs).

3. Three models stand out as having potential application to Developing countries: The OVER/UNDER model (because of its strength in analysing the relationship between uncertain demand and investment requirements), the MIDAS model (for its ability to handle multiple objectives), and the EGEAS/COMPASS/STAFF package developed for EPRI by Stone & Webster, (for its sheer comprehensiveness and pwoer). All three models have been used extensively by American Utilities.

4. Whatever the potential for direct application of such models to developing countries, it is worth recalling the lessons of a decade ago, when American and European Energy Planning models were similarly seen as having potential application to developing countries. The cumulative experience of the last decade indicates that with the exception of a few more advanced countries (such

9 "The Potential Application of American Utility Planning Models to Developing Countries", Working Paper #3, November 1989.

10 Indeed, EPRI has made great efforts to develop, and impose upon its contractors, consistently applied and well enforced documentation requirements. See e.g. "Software Development and Maintenance Guidelines", EPRI EL 3089, May 1983.

as Brazil) such models have not proven to be useful. Perhaps the most important reason is the mismatch between staff cabability, model sophistication, and the committment of donors to provide on-going training and model support.

5. Indeed, if one examines more closely the experience of utility planning models, the only example of a broadly successful model transfer is that of WASP. However this was possible only as a result of the strong institutional committment of the International Atomic Energy Agency (IAEA), that for more than a decade has provided very successful training courses at Argonne National Laboratory, and continued financial support to model improvements and documentation. The implication is that a model of the sophistication, say, of the Stone & Webster Package, would require a sustained committment to training if a systematic transfer were to be achieved.

6. Indeed, again with reference to the experience with energy planning models, the reluctance of the donor community to select some particular model (in the manner in which IAEA selected, and then stood behind WASP), resulted in a profusion of models, none of which was adequately supported. Even if the above-mentioned existing American models are superior to WASP, their complexity mandates that one such model be chosen, and a long term committment provided. Whether or not IAEA could (and should) be persuaded to replace WASP with a package that is more suited to Least Cost Planning remains to be seen.

7. The proprietary nature of many of the best models is of some concern, with software fees in some cases in excess of $50,000. Only very few utiltities can pay that kind of fee, even if hard currency from donor grant funds is available. It is clear that USAID will need to negotiate some kind of site licence to permit use of the model by its overeas missions and clients. The issue here is that whatever the shortcomings of the WASP-based package promoted by IAEA, it is supplied to countries on an official basis at no cost.

Existing Spreadsheet Financial Models for LDC Electric Utilities

Most financial models of electric utilities, including those typically used by the World Bank and other development banks, consist of LOTUS 1-2-3 spreadsheets. These are most often based on more detailed spreadsheets prepared by the utilities themselves, and suffer from two main problems: neither the investment plan, nor the revenues and generation requirements, are dynamically linked to the financial model. Thus kwh sales, the tariff, and fuelcosts appear in the financial model as data, rather than as formulae based on the operation of the technical system -- an approach depicted on Figure 2. Similarly, detailed calculations of debt service and depreciation are performed separately based on an assumed set of construction outlays and start-up dates, and passed in summary form to the appropriate sections of the overall financial calculations.

Indeed, many so-called "financial models" are not really models at all, but are better described as static accounting frameworks. In practice such models cannot be easily used for sensitivity analysis because every change in assumptions requires extensive external computations.

To be sure, in some instances, fuel quantities and fuel prices are separately entered, so that the impact of changing fuel prices can be evaluated within the financial model. However the concomitant impact of a fuel price change on the merit order and dispatching is not included within the financial model, and must be provided by new data from the technical department.

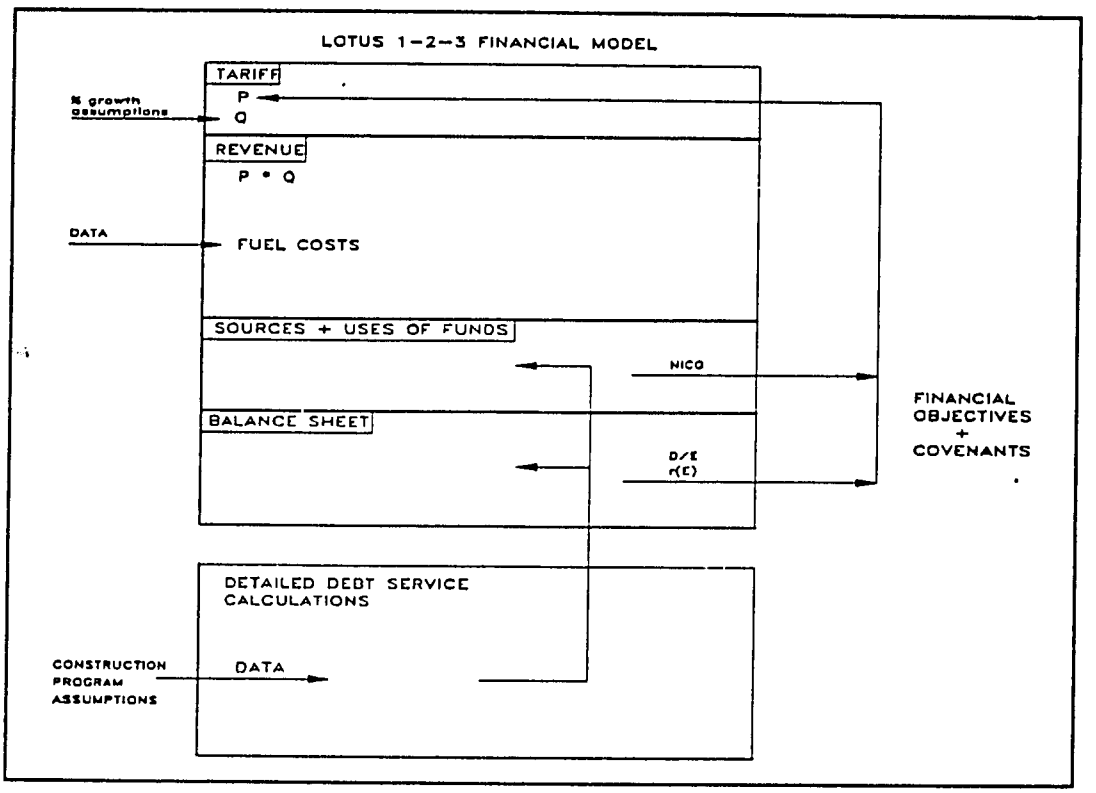

Figure 2: The structure of a typical spreadsheet financial model.

We can thus summarize the most common sequence of analysis as follows:

1. Definition of the investment plan necessary to meet the assumed demand (for which the WASP model is most frequently used). In some cases WASP is run for a series of demand cases (see discussion below, **Capacity Expansion Module**)

2. Debt service and depreciation calculations, with system wide totals passed to the financial model as the "investment plan". Investment requirements for distribution system expansion, rural electrification, etc. are also added.

3. Fuel consumption and kwh sales are determined by the technical departments (usually on the basis of detailed production costing models), passed to the financial department as data. In many cases, financial and technical departments are at different physical locations, and such data are transmitted from one to the other in the form of hand-written memoranda.[11]

4. With these input data, the Financial model is run for conformity to financial objectives and/or covenants imposed by lending institutions. The procedure for finding that set of tariffs that exactly meets the financial objectives is usually ad hoc, rarely under the control of a LOTUS macro.

On Figure 3 we depict the situation in Morocco. Technical and Financial Departments of the Office National d'Electricite are in two different locations: the financial Department is at the ONE Main Office in downtown Casablanca, whereas the technical department that runs the production costing model is located at the Dispatch Center at the Roches Noires Generating Station, some miles to the North of Casablanca.

11 One reason for this separation is that technical departments are often located at the system wide dispatch centers: these are rarely at corporate headquarters that house financial departments.

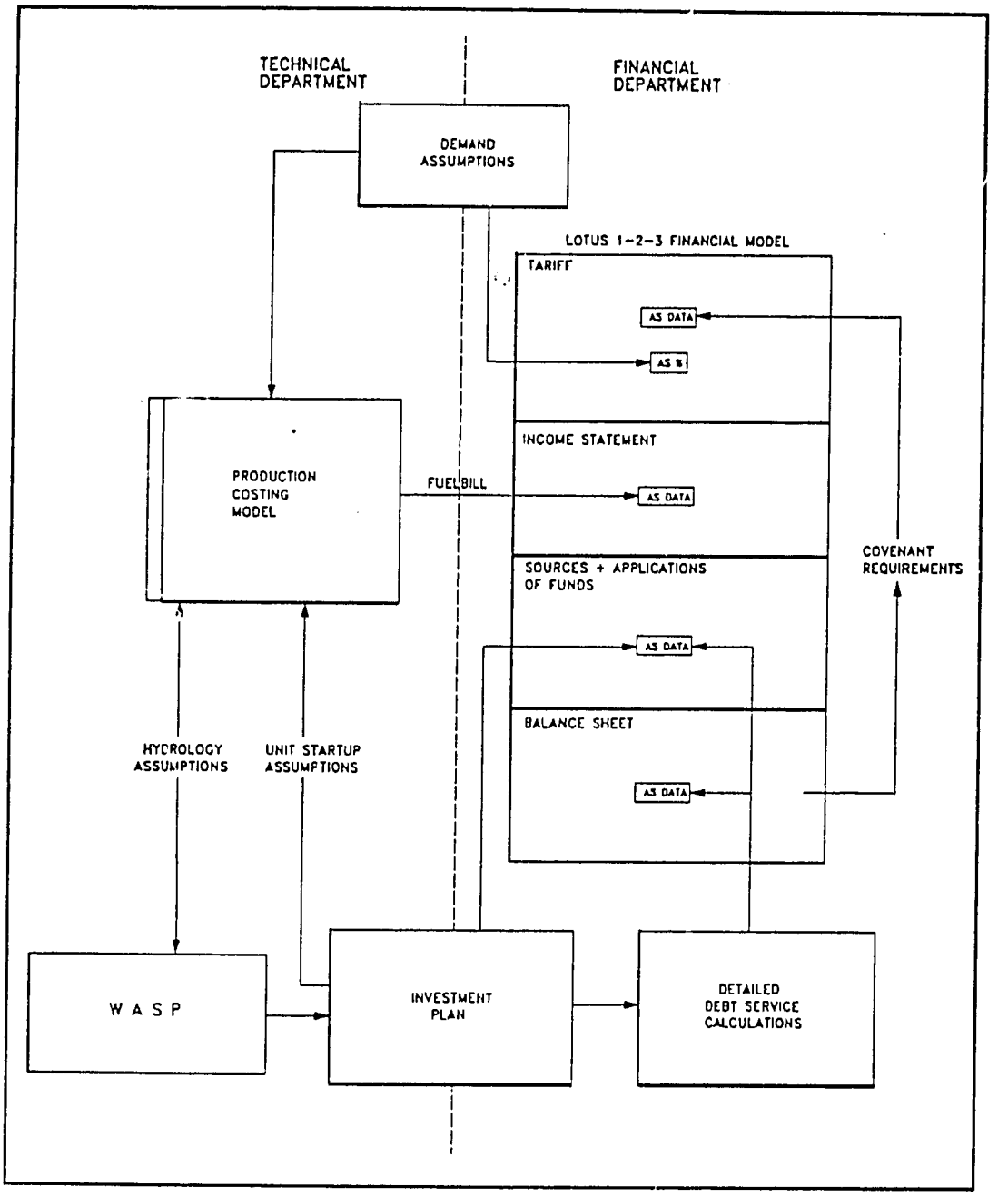

Figure 3: Interaction between technical and financial departments of ONE in Morocco.

For such models to be useful for strategic planning, investment calculations, the financial analysis and the technical configuration must be made dynamic and consistent. For example, a one year delay in the start-up date of a particular generation unit affects not just the construction program outlays, debt service, and depreciation calculations, but also changes the merit order for plant dispatching purposes, and hence the quantity of fuel consumed, and the fuelcost.

As noted, ELECTROPLAN builds on work recently completed as part of a joint World Bank- USAID study of Energy pricing in Morocco. In that work the Bank's financial model of the Office National de l'Electricite, ONE, was extended to incorporate an optimal dispatch and demand model. Since the focus was on the energy sector as a whole, the model also included financial models of the National Coal Company and the two refineries, as well as a representation of the complete flow of energy sector related funds. The general format of the Morocco model is illustrated on Figure 4.

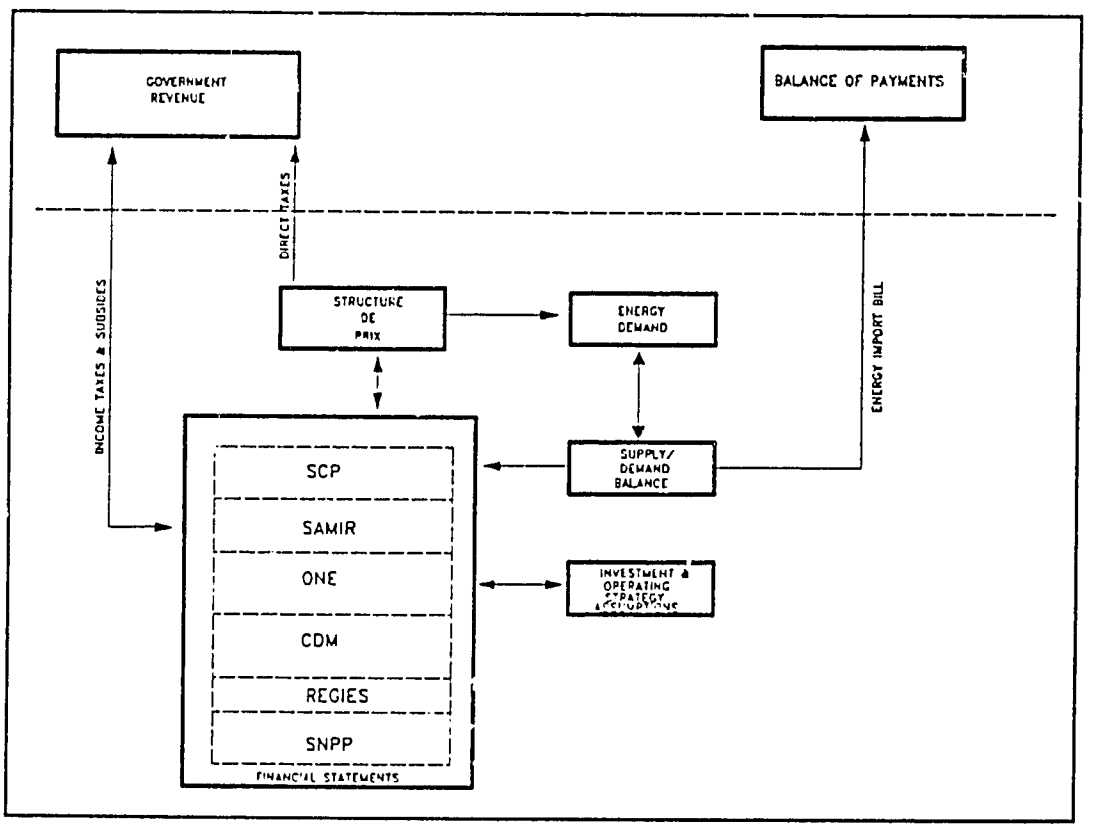

Figure 4: The Morocco Model

3. ELECTROPLAN Overview

ELECTROPLAN consists of four main worksheets and a number of utilities, under the control of the master worksheet ELECTRO.WK! (see Figure 5).[12]

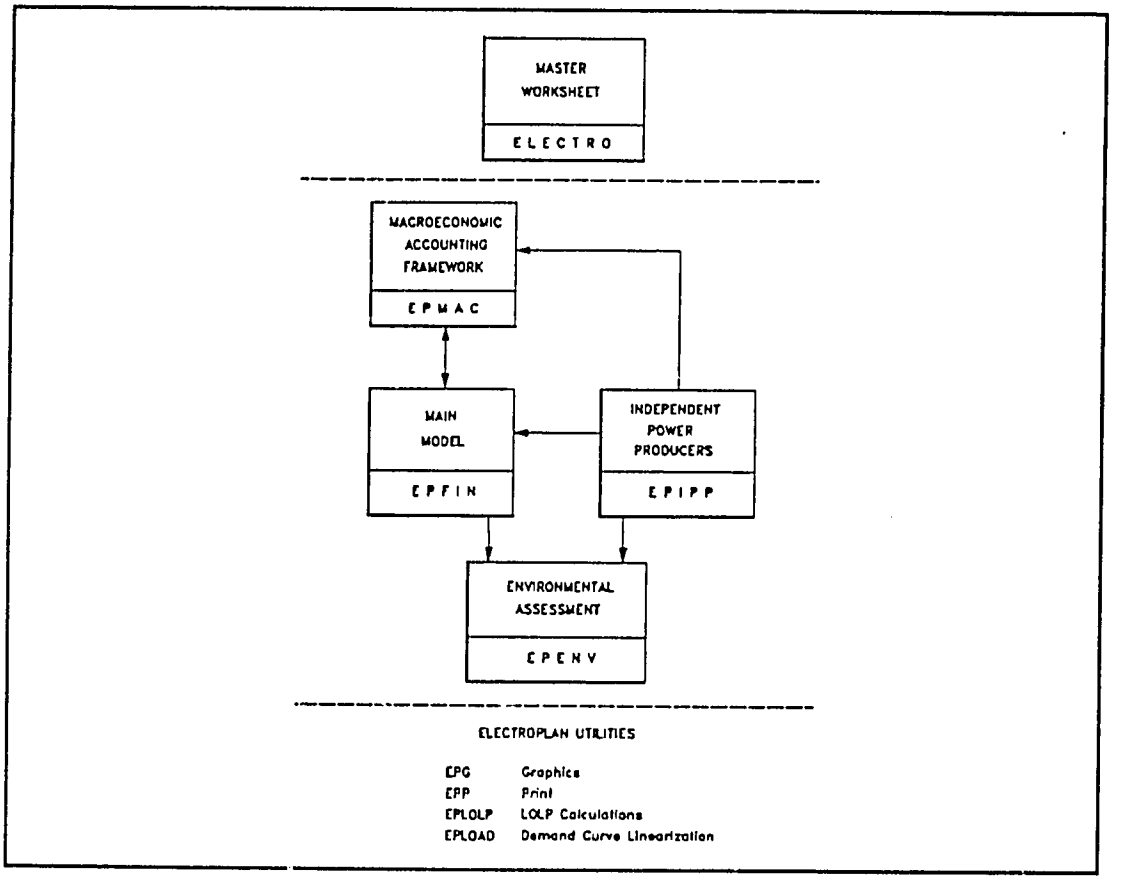

Figure 5: Model Overview.

The EPMAC worksheet contains the overall macroeconomic accounting framework, and all of the assumptions associated with international economic and energy markets (such as assumptions concerning world oil and coal prices, interest and inflation rates etc.). The overall national energy balance, and

12 Version 2 of ELECTROPLAN is based on LOTUS 1-2-3, version 2.01, and runs under the SQUEEZE file compression utility, which gives files the extension .WK! in place of the normal WK1 extension. Unless otherwise, stated all files are so named.

domestic pricing assumptions, are also specified here. Relevant assumptions (such as domestic oil and coal prices), plus constraints such as foreign investment limitations, are passed to the main EPFIN model. Once EPFIN has been run, information on electric sector fuel consumption, investment, debt service and so on are passed back to EPMAC, where it is reaggregated with non-electricity sectors.

The analysis of the economic and financial viability of independent power producers is contained in the EPIPP spreadsheet: this provides for standard IRR and NPV evaluations of proposed schemes. The power and energy produced in each block of the load duration curve are passed to the dispatch module of the EPFIN spreadsheet, where such units are dispatched according to their position in the merit order.[13] The financial arrangements that govern sales to the grid are incorporated by a linkage to the financial module; special considerations such take-or-pay contracts are readily included.

ELECTROPLAN is structured in such a way as to allow multiple IPP's to contribute to the grid: each IPP scheme can be analyzed at whatever level of technical and economic detail as is deemed appropriate: the only restriction of the format of the IPP spreadsheets is that information needed by other spreadsheets in ELECTROPLAN be in the standard format. Existing LOTUS 1-2-3 models can thus easily be modified to meet ELECTROPLAN interface requirements.

At the time of writing, the environmental impacts assessment module is still in the design stage. A complete description will be included in the final version of this report.

13 Depending on the contractual arrangements that govern sales to the grid in specific instances, ELECTROPLAN can also use other rules to simulate the dispatch of IPP units.

ELECTROPLAN is organized in such a way that multiple versions of each spreadsheet can be accommodated. For example, one may wish to create several different macroeconomic scenarios. A two-digit identifier is used for this purpose (thus if two macroeconomic scenarios are present, these would be named EPMAC1.WK!, EPMAC2.WK!). Index files are used to keep track of multiple file versions.[14] Thus, whenever a particular module is invoked from the master menu, the user is presented with the corresponding index that identifies the current files (with a brief one line description, and the file creation date).

14 The index files are named as follows

indexfile name	worksheet
INDEXMAC	Macroeconomic scenarios EPMACj
INDEXFIN	Financial Models EPFINj
INDEXIPP	Independent Power Producers EPIPPj
INDEXENV	Environmental Impact Assessment EPENVj

4. The Main Model: The EPFIN worksheet.

The EPFIN financial spreadsheet represents the core of the model, and is the largest spreadsheet in the ELECTROPLAN system[15]. The overall organization of the EPFIN worksheet is portrayed on Figure 6.

The computational sequence begins with a specification of the investment program, which provides start-up dates and construction outlays for each generation unit. The corresponding investment, depreciation and debt service calculations are passed to the financial statements. The investment plan also encompasses demand side interventions, such as the introduction of more efficient end-use devices: these are entered directly into the demand module. A first calculation of demand is made with a first estimate of the tariff (for which one usually takes present expectations); this provides sales revenue for the financial statements. The unit start-up dates and demand provides the basis for generation dispatch; the resultant fuelcosts are also passed to the utility income statement. The financial statements are then recalculated, and actual financial performance compared to target values. If necessary, adjustments are made to the tariff, and the computational procedure is repeated.

The end result of this sequence is a completely consistent set of demands, prices, and financial statements for a given investment plan, with financial performance meeting specified criteria. The model then allows for a re-adjustment of the utility investment plan: for example, if sharp tariff increases are necessary to meet financial criteria, demand will fall: but this in turn means that not so much installed capacity is necessary to meet a given level of reliability. The same effect follows from demand-side investments, or from the sales of electricity from Independent Power Producers (IPPs). The details of how the investment plan is modified is presented below (in Section 4.3): since one wishes to avoid having to run WASP or some other comparable generation expansion optimization program at each iteration a small expert system is under development to provide for capacity expansion plan adjustments.

15 The test version of EPFIN, which provides for a 8-year simulation (1989-1996), contains about 1700 active rows (plus another 700 rows for macros). It consumes essentially all of the DOS-available memory plus close to 1 Emigrate of expanded memory. Unsqueezed it occupies 780k of disk space, in squeezed form about 250k.

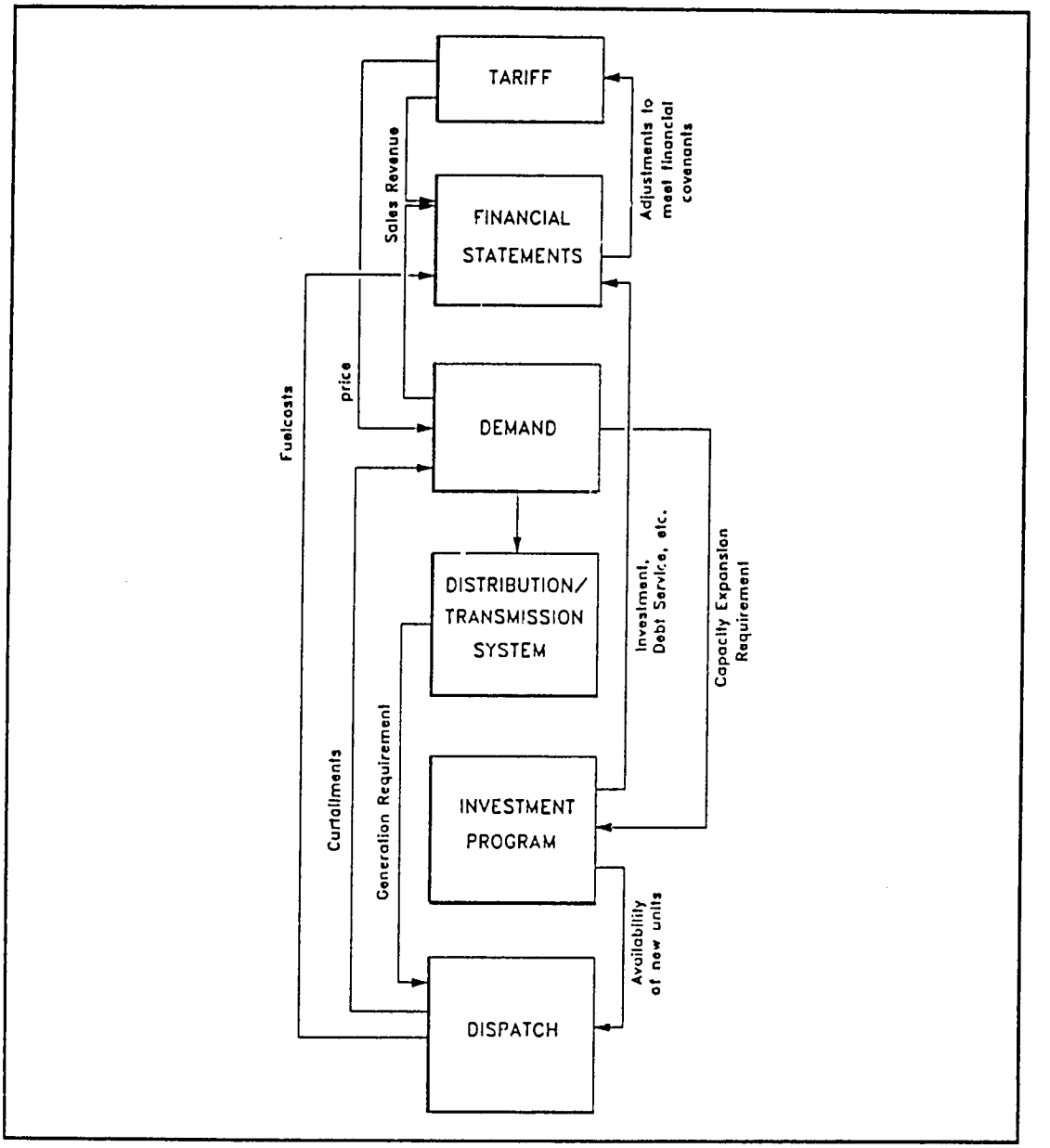

Figure 6: The EPFIN worksheet

4.1 The Financial Module

The Utility Financial Module is depicted on Figure 7. Apart from the various dynamic linkages already discussed, the most important feature is the automated procedure for adjusting the tariff to meet stated financial targets such as return on assets, self financing ratio, debt service coverage, etc. The user is free to define whatever criteria are deemed appropriate to a given situation; these are entered as LOTUS formulae in the section "Actual Ratio Values". The user must also specify a target value for each criterion so specified: it should be noted that the target need not be some fixed value applicable for the duration of the planning period, but can vary from year to year. If desired, the target can itself be defined by formula.

In the first iteration, some initial set of prices P_0 is used, with an adjustment factor A_0 set to unity: typically the initial set of prices is based on the current plan for tariff increases. These prices are then used to calculate the financial statements and a first calculation of actual ratio values.

The actual ratio values are compared to the target values, and a factor is computed that adjusts the tariff level at the next iteration of the calculation. The process is repeated until actual ratio values are equal to targets (to within some specified convergence criterion), or until some prespecified number of iterations have been reached.[16]

The convergence properties of this procedure are illustrated on Figure 8; obviously the number of iterations required is to some extent a function of the difference between starting value and that required to meet the target. However, note that the process converges for a wide range of starting values, and that convergence is extremely rapid.

16 The logic here results in what LOTUS terms "circular reference"; this is an intended condition in this application, not indicative of formula error.

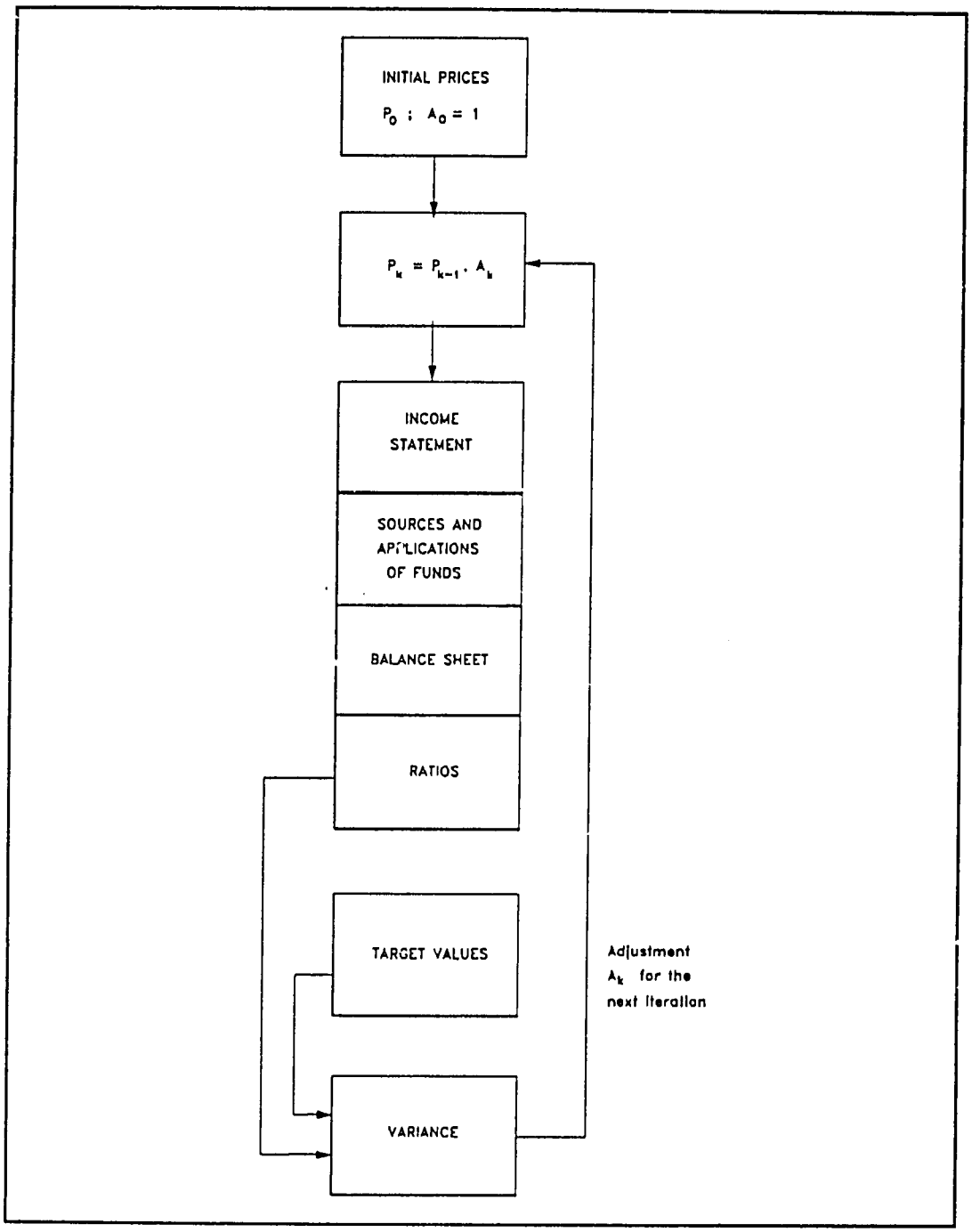

Figure 7: Iterative scheme for Financial Module Computations.

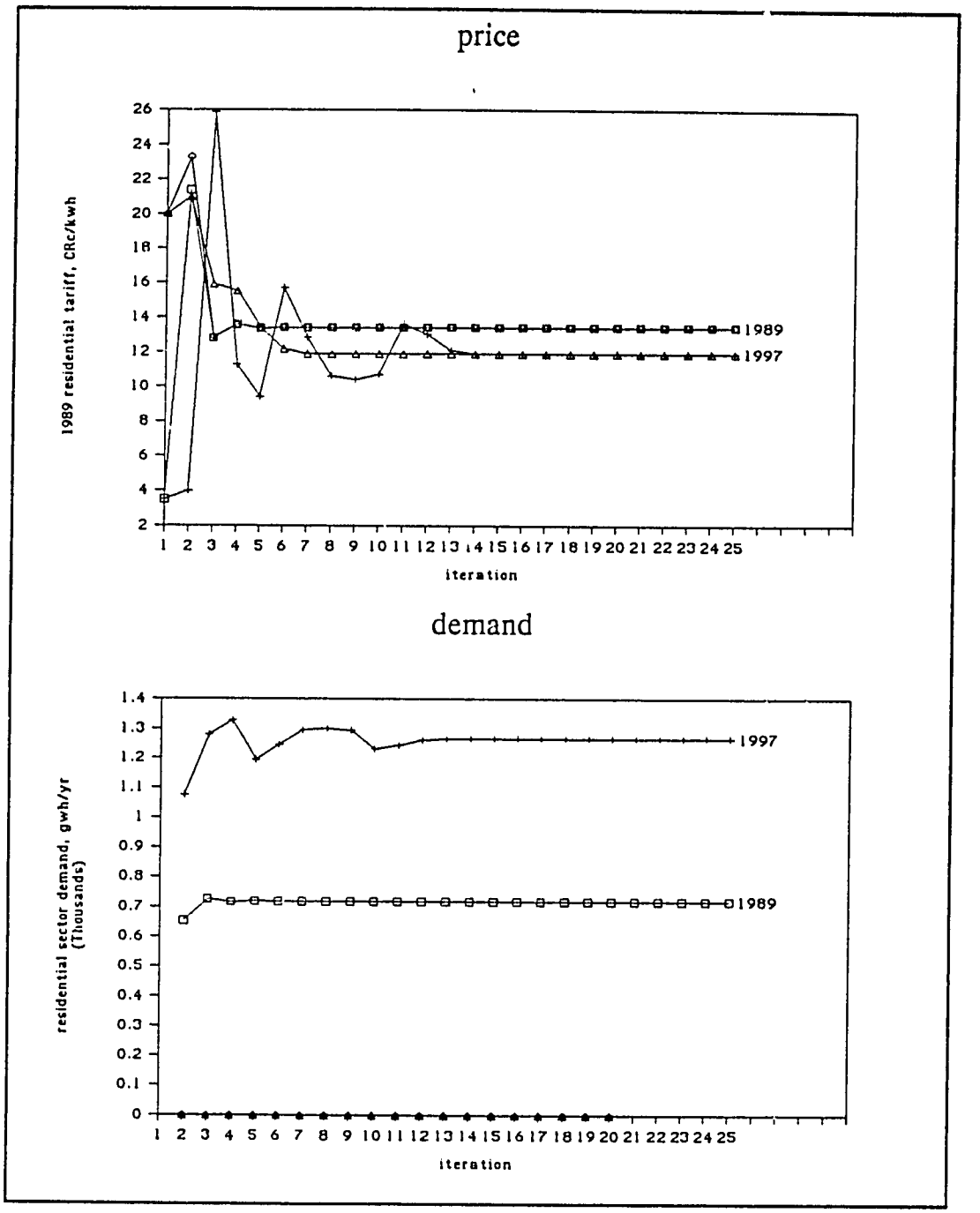

Figure 8: Convergence properties of financial module calculations.

The financial model is provided with an automatic working capital finance facility. The user must specify some minimum level of cash, either as values, or by formula (say related to operating outlays). If the change in working capital (as calculated by the sources and applications of funds table) results in year-end cash that is below this value, then short term finance is made available to make up the difference. This is assumed re-paid the next year. Fundamental financial imbalances will often be reflected in a rapid build-up of such short-term finance: however by specifying reasonable targets for self-financing the automatic adjustment procedure elaborated above will almost always provide a reasonable overall financial projection.

4.2 The Investment Module

The investment module provides a completely dynamic computation of investment outlays, depreciation, accounting for construction work in progress and transfer to fixed assets, and debt service. All calculations are performed on a plant by plant basis in the case of generation facilities, and on a program basis for distribution and transmission. Utility-wide totals are passed to the corresponding line item of the financial statements.

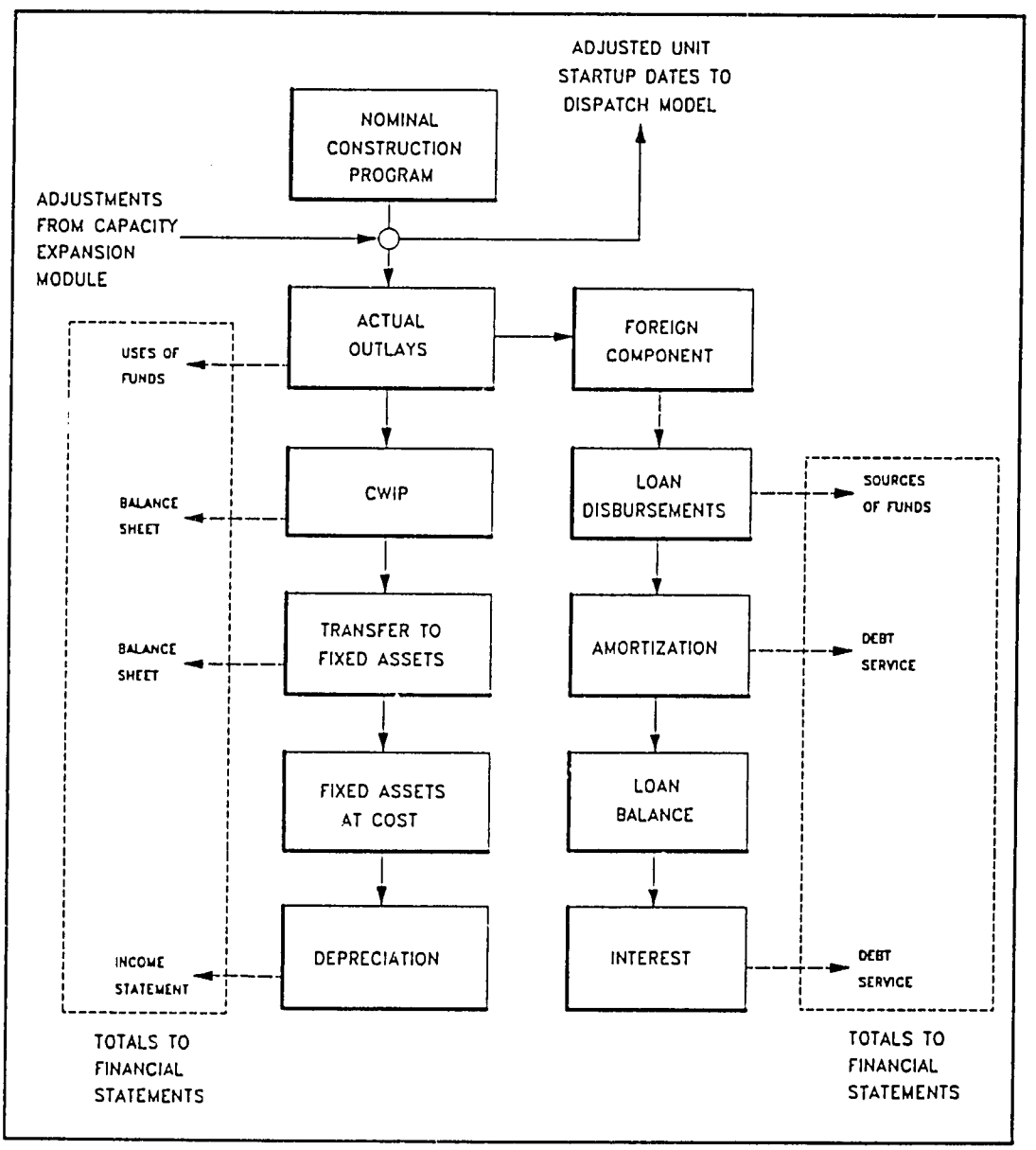

Figure 9: The Investment Module

The starting point for these calculations is the definition of the nominal construction program, typically the presently expected program of the utility. On Table 1, overleaf, we show such a nominal program for the ICE Utility of Costa Rica. The year by year construction outlays for each plant are specified, together with the nominal start-up date for each unit. Distribution and transmission projects are listed separately, below.

Table 1: Nominal Construction Program of ICE, Costa Rica.

	project	status		nominal startup	1989	1990	1991	1992	1993	1994	1995
1	Ampliacio	fixed	hydro	1990	131	0	0	0	0		
2	Gas-I 2x3	fixed	fueloil	1990	19						
3	Gas-II 2x36		fueloil	1991		1920	1129				
4	Geothermal Unit I		geothermal	1992	1372	2890	1981	304	0	0	0
5	Sandillal		hydro	1993	1301	482	579	416	0	0	0
6	Toro		hydro	1994	0	599	955	2034	857	0	0
7	Geothermal Unit II		geothermal	1994	14	312	1042	2214	1756	0	0
8	Gas-III 36		fueloil	1995				166	520	81	81
9	Gas-IV 36		fueloil	1996					166	520	520
10	Low-Speed Diesels		fueloil	1996	0	0	0	0	309	1648	1648
11	Geothermal Unit III		geothermal	1997	0	0	0	14	312	1042	1042
12	Geothermal Unit IV		geothermal	1997	0	0	0	14	312	1042	1042
13	Gas-V 36		fueloil	1998							
14	Angostura		hydro	1999	46	46	46	46	1327	2985	2985
15											
16											
17											
18											
19											
20											
21											
22											
	non-generation										
1	Power Development I		DIST		13	670	851	721			
2	Power Development II		DIST		0	488	452	311	336	0	0
3	Rural Elec. II stage		RE		0	0	0	0	228	422	626
4	Dist.Prog. 1994-1997		DIST		0	0	0	0	0	0	0
5	Power Development I		TRANS		13	266	704	881	0	0	0
6	Power Development II		TRANS		0	107	468	65	54	0	0
7	Trans.Prog. 1994-199		TRANS		0	0	0	0	0	121	1376
8	Ongoing projects		OTHER		2334	1265	1265	1265	1265	1265	1265
9											
10											
11											
12											
	total construction outlays				5243	9045	9472	8451	7442	9126	10585

The outlays actually used by the model are specified in a separate table. In the column "delta", the user enters the variation to the nominal start-up year: a delay of two years would be indicated by +2, an acceleration of one year by -1. The construction outlays indicated in the first table are then shifted by the corresponding number of columns: in the example used here, the Sandillal hydro unit is assumed to be delayed 2 years.

Whilst the user is free to make adjustments of start-up dates by hand, systematic adjustment procedures are also available as model options. For example, a procedure is available to adjust capacity expansion plans in response to lower (or higher) demands that follow from changes in tariff, or from demand-side investments. The automatic adjustment procedures are described below (in Section 4.3).

Table 2: Construction outlays used by the Model

	project	delta	actual start-up	1989	1990	1991	1992	1993	1994	1995
1	Ampliaciones (EBYN)	0	1990	131	0	0	0	0	0	0
2	Gas-I 2x36	0	1990	19	0	0	0	0	0	0
3	Gas-II 2x36	0	1991	0	1920	1129	0	0	0	0
4	Geothermal Unit I	0	1992	1372	2890	1981	304	0	0	0
5	Sandillal	3	1996	0	0	0	1301	482	579	416
6	Toro	2	1996	0	0	0	599	955	2034	857
7	Geothermal Unit II	3	1997	0	0	0	14	312	1042	2214
8	Gas-III 36	2	1997							
9	Gas-IV 36	1	1997							
10	Low-Speed Diesels	1	1997							
11	Geothermal Unit III	0	1997							
12	Geothermal Unit IV	0	1997							
13	Gas-V 36	0	1997							
14	Angostura	0	1997							
15				0	0	0	0	0	0	0
16				0	0	0	0	0	0	0
17				0	0	0	0	0	0	0
18				0	0	0	0	0	0	0
19				0	0	0	0	0	0	0
20				0	0	0	0	0	0	0
21				0	0	0	0	0	0	0
22				0	0	0	0	0	0	0
	non-generation									
1	Power Development I	0	0	13	670	851	721	0	0	0
2	Power Development II	0	0	0	488	452	311	336	0	0
3	Rural Elec. II stage	0	0	0	0	0	0	228	422	626
4	Dist.Prog. 1994-1997	0	0	0	0	0	0	0	0	0
5	Power Development I	0	0	13	266	704	881	0	0	0
6	Power Development II	0	0	0	107	468	65	54	0	0
7	Trans.Prog. 1994-199	0	0	0	0	0	0	0	121	1376
8	Ongoing projects	0	0	2334	1265	1265	1265	1265	1265	1265
9	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0
	total construction outlays			3882	7606	6850	5461	3632	6104	9442

Once the adjusted construction outlays have been determined, the remaining calculations follow in order: while construction is still under way, outlays are carried as Construction Work in Progress (CWIP); in the start-up year the cumulative CWIP is transferred to fixed assets at cost. Depreciation is assumed to commence in the start-up year, with the depreciation period specified by the user.

In the default version of the model, it is assumed that the domestic component of construction is self-financed, whilst the foreign component is financed by a foreign loan[17]. In the event that domestic project financing is also used, an additional set of tables is readily added. The foreign debt component of construction outlays is specified by the user, and shifted in accordance with the adjustment made to the start-up years as noted above. Calculations of loan disbursements, amortization and interest payments follow. Interest rate, grace period and loan repayment period are specified for each plant by the user.

The totals for each set of calculations are passed back to the financial statements by formula. Thus the financial statements are dynamically dependent on the investment program: any changes to start-up years, or to individual unit costs, etc, are immediately reflected in the financial module.

17 However, the financial model is provided with an automatic working capital financing facility in the event that overall cashflows are inadequate (see above, section 4.1).

4.3 The Capacity Expansion Module

As the model makes its adjustments to the demand to be supplied by the central grid, changes to the investment plan must also be made. For example, if demand side investments are made to reduce peak demands, then to meet the same level of generation reliability as before less generation capacity is required. However, because of the lumpiness of investment outlays, adjusting the generation capacity expansion plan is not a simple matter. In the ideal case, at each iteration of the overall scheme one would re-run a complete generation expansion optimization model. However, this is obviously not a practical solution in an analytical environment that stresses the ability to run extensive sensitivity analyses with minimal recalculation time. Moreover, even if it were computationally feasible[18], it is unclear that it would be desirable to run a highly detailed, complex model as part of the computational scheme at the first and second levels of the modelling hierarchy.

As a first order approximation, the model is equipped with an adjustment algorithm that adjusts the expansion path by accelerating or decelerating the start-up years of units in the initial investment plan, in such a way that the average reserve margin in the original optimal plan is maintained. Because of the lumpiness of investments, this adjustment cannot provide exactly equivalent reserve margins in all years. However, ELECTROPLAN is equipped with a utility that makes a rigorous calculation of Loss of Load Probability (LOLP) for a given slate of generating units.

The procedure is illustrated on Figure 10.[19] Whenever the reserve margin would otherwise fall below the "reserve margin basis", the next expansion is assumed to occur, with the actual (or "outcome") reserve margin as calculated by the model fluctuating around the planning reserve margin (PRM): the larger the average size of plants, the greater will be the magnitude of these fluctuations[20].

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18 With advanced operating systems now becoming available that permit a single microcomputer to be configured as several virtual machines, it may be possible to run each level of the modelling system in its own virtual machine, interfaced by an additional virtual machine configured as a file server. However, such an approach would still be very much in the research domain.

19 This is the same specification as used in the EPRI OVER/UNDER model.

20 Of course a rigorous calculation of LOLP would show similar fluctuations through time around the specified average LOLP target.

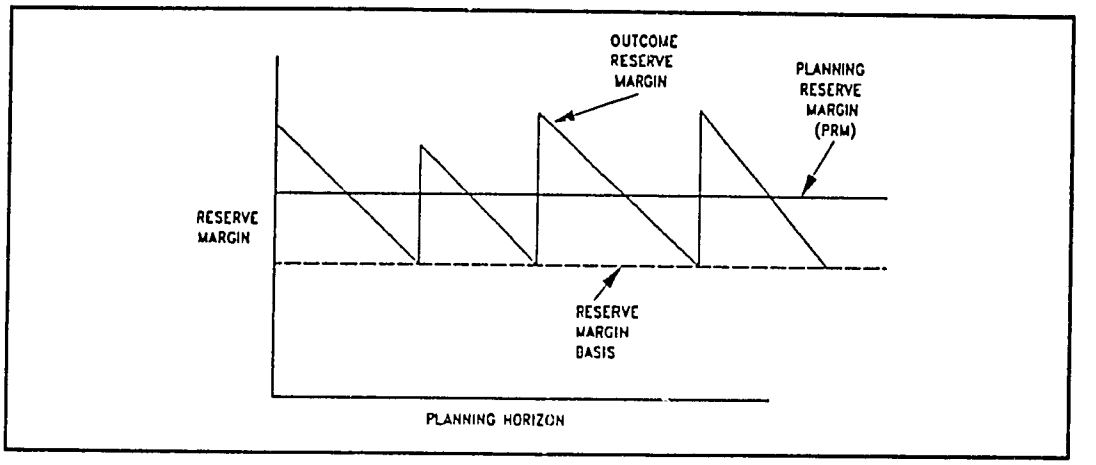


Figure 10: The Planning Reserve Margin

The results of the ELECTROPLAN adjustment procedure are illustrated on Figure 11, which shows the original demand and capacity path, and those associated with an ELECTROPLAN equilibrium solution (whose demands are sharply reduced by tariff increases and a hypothetical demand-side investment program).

The most important issue in such an adjustment procedure is the degree to which the so-adjusted expansion plan differs from the optimum solution provided by a re-optimization of the detailed expansion planning model. In fact there is sufficient evidence to suggest that the error involved in such a procedure is relatively small. On Table 3 we show the results of a series of WASP runs for Costa Rica for a sequence of scenarios starting with a high case (alto), which has a year-2000 peak demand of 1470 Mw, with successive reductions in demand to the case Bajo II, with a 2000 peak demand of 980 Mw. We show here the start-up dates for all of the units that are part of the optimal plan in the high demand case: inspection of this table shows that indeed WASP responds to diminished demands by postponing thermal units. For example, the second 32Mw gas turbine unit which comes on-line in 1990 in the high case, is postponed 6 years in the base case, 7 years in the Bajo I case, and more than 10years in the Bajo II case.

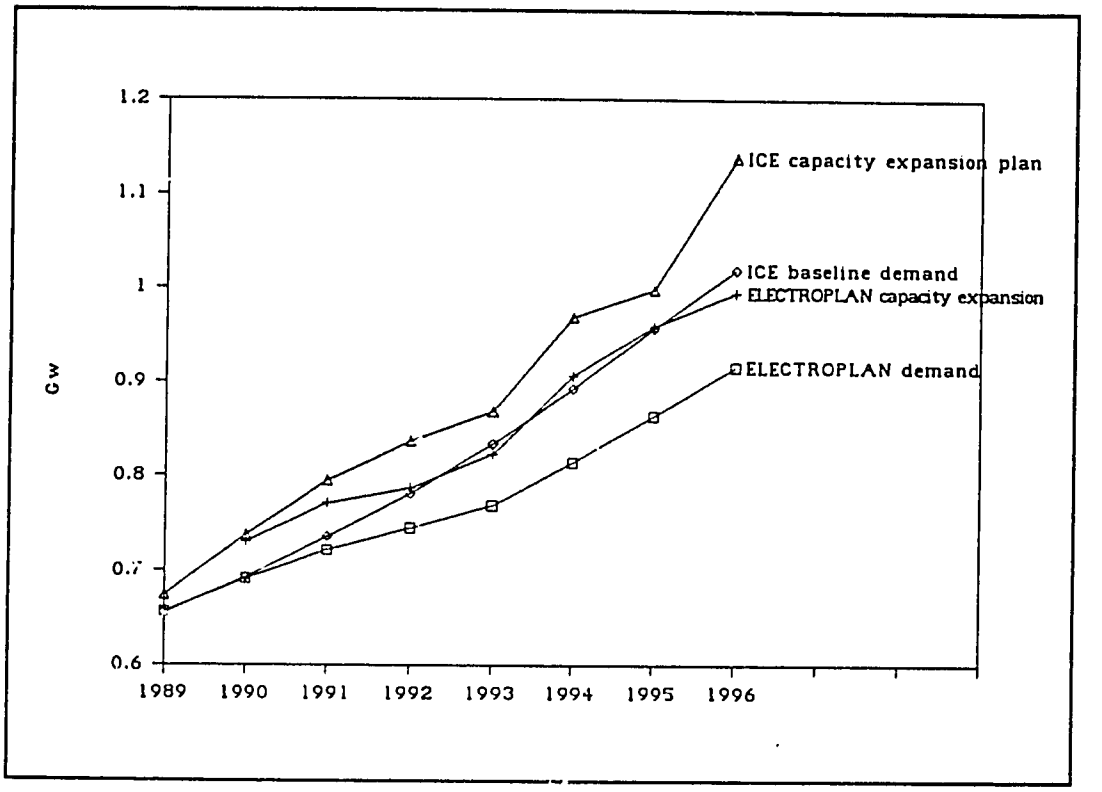


Figure 10: Automatic adjustment of the capacity expansion plan.

More importantly, however, Table 3 points to a major shortcoming of WASP: the model provides an optimal configuration of thermal plants to meet a given LOLP only for some given, exogenously specified sequence of hydro plants. Thus the fact that start-up dates for the four hydro units scheduled for the mid 1990's (Sandillal, Mirvalles II, Toro I and II) remain unchanged from Alto to Bajo II is likely to be a result of exogenous specification rather than of global optimality. One advantage of ELECTROPLAN is that it is extremely easy to run a sensitivity analysis on such assumptions.

Table 3 : Startup dates as a function of Demand Scenario

	Alto	Base	Bajo I	Bajo II
2000 demand, Mw	1470	1154	1094	980
PT Gas I (32 Mw)	1989	1993(+4)	1997(+8)	1999(+10)
PT Gas II (32 Mw)	1990	1996(+6)	1997(+7)	-
PT Gas III (32 Mw)	1990	2000(+10)	-	-
Mirvalles I (55 Mw)	1991	1991(0)	1992(+1)	1992(+1)
PT Gas IV (32 Mw)	1991	-	-	-
PT Gas V (32 Mw)	1992	-	-	-
Sandillal (32 Mw)	1993	1993(0)	1993(0)	1994(+1)
Mirvalles II (55 Mw)	1993	1993(0)	1996(0)	1997(+7)
Toro I (24 Mw)	1994	1994(0)	1994(0)	1995(+1)
Toro II (66 Mw)	1994	1994(0)	1994(0)	1995(+1)
PT Gas VI (32 Mw)	1995	-	-	-
PT Gas VII (32 Mw)	1995	-	-	-
Angostura (177 Mw)	1996	1998(+2)	1998(+2)	-
Mirvalles III (55 Mw)	1997	1997(0)	2000(+3)	1998(+1)
Siquirres (154 Mw)	1998	-	-	-
Mirvalles IV (55 Mw)	1999	2000(+1)	-	2000(+1)
Carbon (125 Mw)	2000	-	-	-

Although in the sample case presented above the adjustment procedure seems quite reasonable, clearly the validity of this approach needs to be confirmed on a more general basis. In consequence we are presently reviewing a number of countries for which WASP runs have been run for a series of demand cases (similar to the example of Costa Rica shown above). We are also developing a "screening curve" utility (similar to that used in WASP model runs) to provide guidance on the response to changing relative fuel prices, demands and construction costs. The objective is to build a "mini expert system", whose rules can be used to provide guidance on adjusting a base case investment program derived from a WASP run. A full presentation of these results will be included in the next version of this report.

The preoccupation with least cost "optimality" is not one shared by most EPRI strategic planning models. For example, in the EPRI OVER/UNDER model, the capacity mix is entered exogenously in the form of "target mixes", as shown on Figure 12.

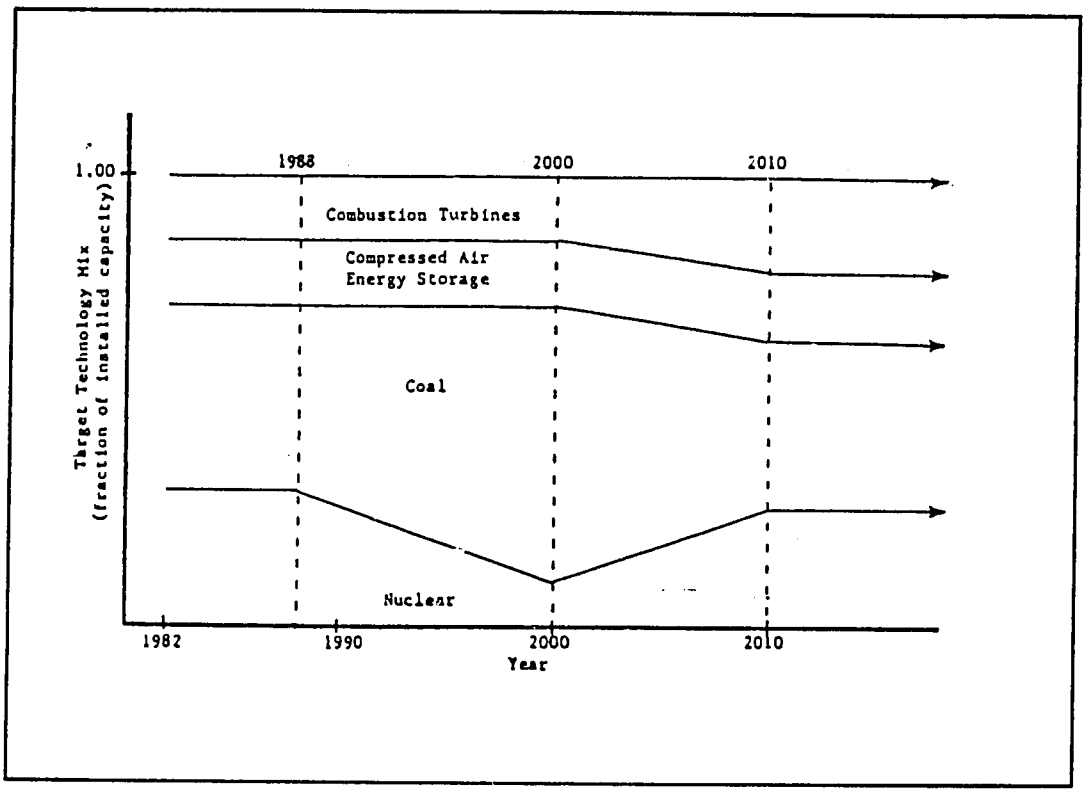
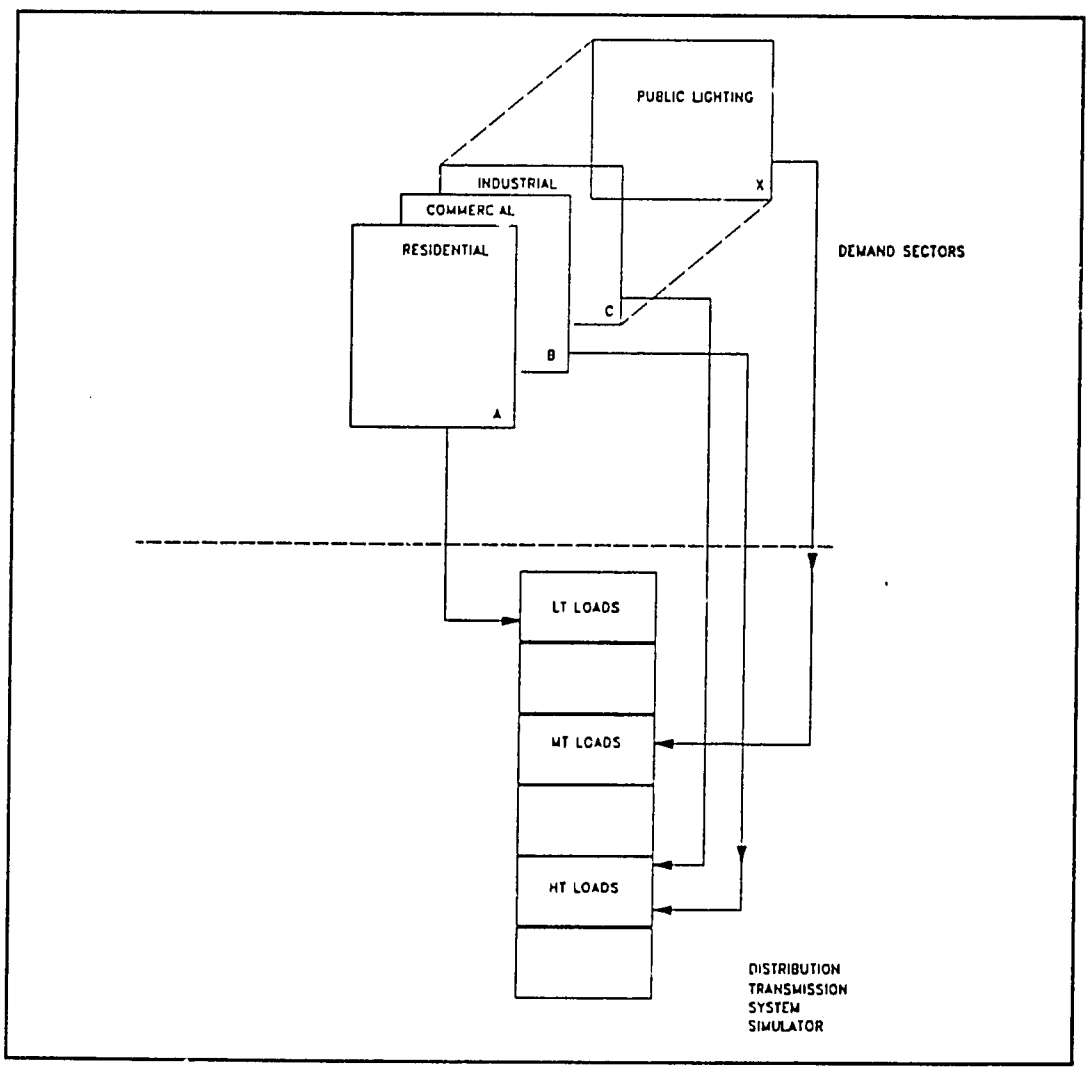


Figure 12: Target Capacity Mix Specification of the EPRI OVER/UNDER Model

4.4 The Demand Module

The overall structure of the demand module is shown on Figure 13. The default version of the model provides for four individual demand sectors, each tied to a separate tariff. A simple command permits the user to insert additional sectors; rows are inserted at the proper place and a complete demand template is imported. The user need only make a linkage to the appropriate LT, MT or HT busbar (by modifying a formula to ensure that the corresponding load is added), and make a linkage to the tariff block[21].



21 The details of the procedure are elaborated in the Software User Manual; in the new version of ELECTROPLAN based on LOTUS version 3.0, each demand sector is modelled in its own spreadsheet, and insertion into an existing spreadsheet is no longer required.

Figure 13: Demand Module Structure

The computational procedure for each demand subsector is as follows. First an estimate is made of the unconstrained demand, D. From this is subtracted the demand reduction from demand-side efficiency investments, E: in the sample data table included in the following pages, we hypothesize a program that replaces conventional incandescent light fixtures in the residential sector by high efficiency fluorescent lights. We also adjust this demand for tariff induced load shifting, T, and for direct load control, L.

Some part of this adjusted demand is met by the grid, say G. If there are grid outages and curtailments, however, some part of this demand cannot be met by the grid: let this be denoted C. Thus

Eq.[1] $D - E - T - L = G + C$

Consumers respond to outages and curtailments by self-generation, S; the balance is unserved demand, say U. Thus what is actually supplied by the grid, G, is given by

Eq.[2] $G = D - E - S - U - T - L$

This analysis is repeated for each block of the load curve. Curtailments and generation outages are passed to the demand module from the dispatch module, and represent the difference between unconstrained demand and the ability of the grid to supply that demand (which in turn is governed in the model by the availability of units as specified in the investment plan). Transmission and distribution system outages are calculated in the distribution system module, discussed below (in Section 4.5).

Figure 14 depicts the results of such an analysis (for the residential sector of Costa Rica). Associated with each term on the right-hand side of equation 2 is a corresponding cost, also shown on Figure 14. The spreadsheet layout is illustrated on Table 4, overleaf.

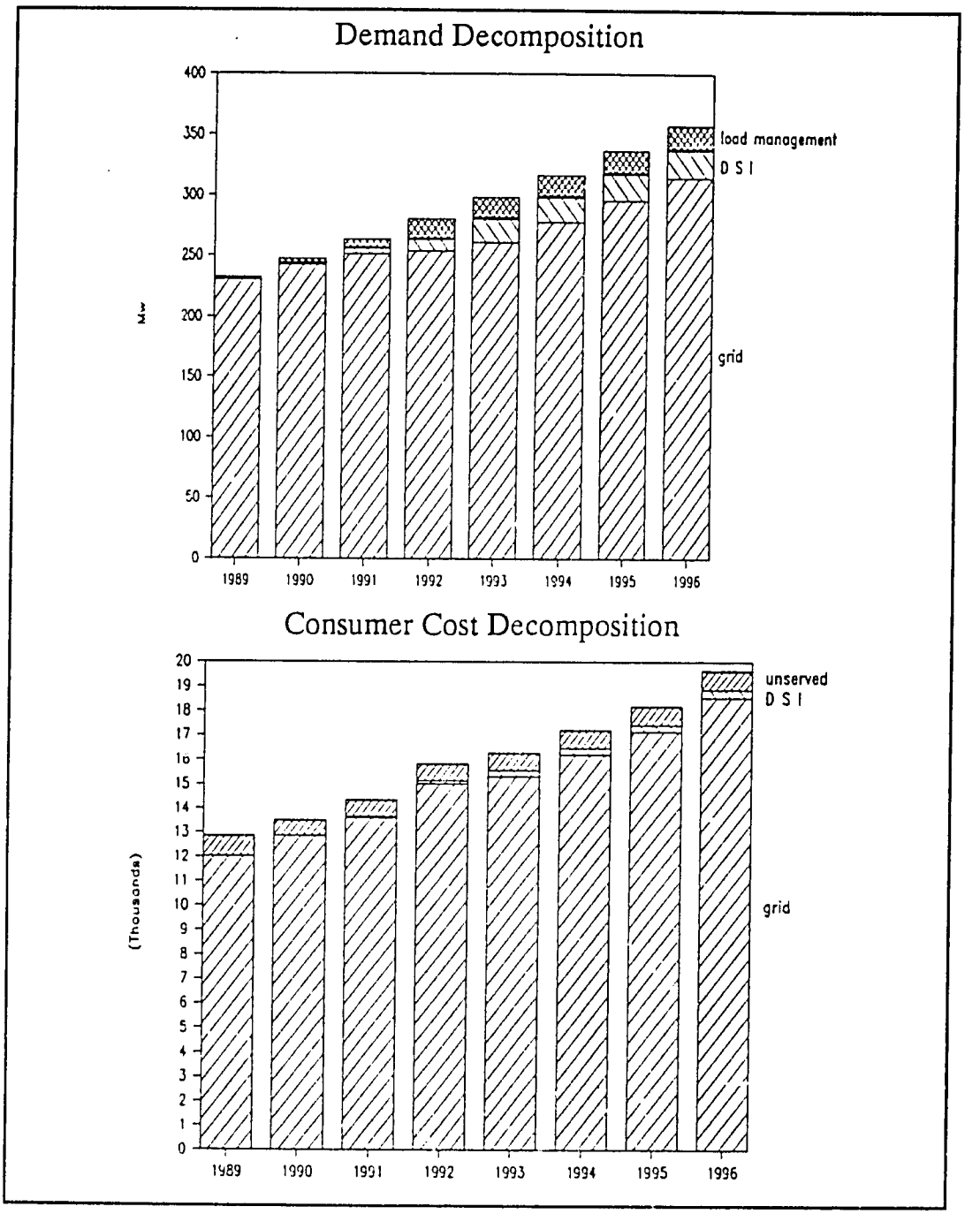


Figure 14: Demand Decomposition

Table 4: Demand Sector Calculations: Costa Rica Residential Sector

Table F1: Residential Demand

				baseyear	1989	1990	1991	1992	1993
1. residential									
growth rate					6.00%	6.00%	6.00%	6.00%	6.00%
additional connections					28.9	30.6	32.4	34.4	36.4
number of connections (1000)				481	510	540	573	607	644
kwh/connection				2820	2820	2820	2820	2820	2820
gwh demand				1356	1438	1524	1616	1712	1815
load profile		0.66	hrs/yr	f					
	needle-1		279	1	249	264	279	296	314
	peak-1		813	0.6	149.2	158.2	167.7	177.7	188.4
	int-1		3354	0.45	111.9	118.6	125.7	133.3	141.3
	base-1		2130	0.4	99.5	105.4	111.8	118.5	125.6
	needle-2		91	0.95	236.3	250.4	265.5	281.4	298.3
	peak-2		273	0.6	149.2	158.2	167.7	177.7	188.4
	int-2		1118	0.4	99.5	105.4	111.8	118.5	125.6
	base-2		702	0.35	87.0	92.3	97.8	103.7	109.9
	net energy demand				1012	1073	1138	1206	1278
2. Tariff induced changes to load curve shape									
	needle>int			0.08	0.000	0.004	0.008	0.021	0.021
	needle>base			0.08	0.000	0.004	0.008	0.021	0.021
	peak>int			0.08	0.000	0.004	0.008	0.021	0.021
	peak>base			0.08	0.000	0.004	0.008	0.021	0.021
	needle>int			0.08	0.000	0.004	0.008	0.021	0.021
	needle>base			0.08	0.000	0.004	0.008	0.021	0.021
	peak>int			0.08	0.000	0.004	0.008	0.021	0.021
	peak>base			0.08	0.000	0.004	0.008	0.021	0.021
3. Load management: Direct interventions, in Mw									
	noncoincident peak reduction>				-1.50	-1.50	-3.00	-4.79	-4.79
			f(p)	f(s)					
	needle-1		0.7		-1.05	-1.05	-2.10	-3.35	-3.35
	peak-1		0.7		-1.05	-1.05	-2.10	-3.35	-3.35
	int-1			0.5	0.24	0.24	0.49	0.78	0.78
	base-1			0					
	needle-2		0.7		-1.05	-1.05	-2.10	-3.35	-3.35
	peak-2		0.7		-1.05	-1.05	-2.10	-3.35	-3.35
	int-2			0.5	0.24	0.24	0.49	0.78	0.78
	base-2			0					
plant costs for direct load control					1.60	1.60	3.20	4.85	4.85
4. load curve after load management adjustments									
	needle-1				247.64	260.50	273.08	280.53	297.57
	peak-1				148.16	155.88	163.01	166.98	177.20
	int-1				112.15	119.10	126.71	135.47	143.55
	base-1				99.47	105.81	112.53	120.69	127.93
	needle-2				235.20	247.43	259.32	266.34	282.52
	peak-2				148.16	155.88	163.01	166.98	177.20
	int-2				99.72	105.92	112.73	120.63	127.82
	base-2				87.04	92.63	98.56	105.86	112.21
	net energy				1012	1073	1137	1204	1277

Table F1: Residential Demand

				baseyear	1989	1990	1991	1992	1993
5. Demand Side Investments									
high efficiency lighting	penetration, %HH				0.00%	1.00%	5.00%	10.00%	20.00%
households with device		(1000s)			0	5	29	61	129
peak Kw saved per HH					0.15	0.15	0.15	0.15	0.15
installed Savings, Mw					0.00	0.81	4.30	9.11	19.31
device life			2	years					
investment		1980.00		/HH	0.00	10.70	56.71	120.24	254.90
load curve impact	needle-1			1.0	0.0	0.8	4.3	9.1	19.3
(in Mw)	peak-1			1.0	0.0	0.8	4.3	9.1	19.3
	int-1			0.3	0.0	0.2	1.3	2.7	5.8
	base-1			0.0	0.0	0.0	0.0	0.0	0.0
	needle-2			1.0	0.0	0.8	4.3	9.1	19.3
	peak-2			1.0	0.0	0.8	4.3	9.1	19.3
	int-2			0.3	0.0	0.2	1.3	2.7	5.8
	base-2			0.0	0.0	0.0	0.0	0.0	0.0
	net energy saved				0	2	12	25	54
6. outages and curtailments			f						
	needle-1		1		17.6	17.6	17.6	17.6	17.6
	peak-1		1		0.0	0.0	0.0	0.0	0.0
	int-1		1		0.0	0.0	0.0	0.0	0.0
	base-1		1		0.0	0.0	0.0	0.0	0.0
	needle-2		1		15.6	15.6	15.6	15.6	15.6
	peak-2		1		0.0	0.0	0.0	0.0	0.0
	int-2		1		0.0	0.0	0.0	0.0	0.0
	base-2		1		0.0	0.0	0.0	0.0	0.0
	net energy unserved				6	6	6	6	6
7. Self generation									
%HH with standby generator				1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
# Households	(1000s)			4.810	5.099	5.405	5.729	6.073	6.437
average size		0.25	Kva		0.25	0.25	0.25	0.25	0.25
cost per unit		66000	/kva		16500	16500	16500	16500	16500
fixed O&M costs		2%	of cap costs						
variable O&M costs		2.64	/kwh						
installed capacity			Mva		1.275	1.351	1.432	1.518	1.609
			Mw		1.020	1.081	1.146	1.215	1.287
capacity additions			Mva		0.072	0.076	0.081	0.086	0.091
output, in Mw	needle-1			100%	1.020	1.081	1.146	1.215	1.287
	peak-1			50%	0.000	0.000	0.000	0.000	0.000
	int-1			20%	0.000	0.000	0.000	0.000	0.000
	base-1			5%	0.000	0.000	0.000	0.000	0.000
	needle-2			100%	1.020	1.081	1.146	1.215	1.287
	peak-2			50%	0.000	0.000	0.000	0.000	0.000
	int-2			20%	0.000	0.000	0.000	0.000	0.000
	base-2			5%	0.000	0.000	0.000	0.000	0.000
	net energy				0.377	0.400	0.424	0.449	0.476

Table F1: Residential Demand

			baseyear	1989	1990	1991	1992	1993
costs of self generation								
capital				4.76	5.05	5.35	5.67	6.01
operating				1.00	1.06	1.12	1.19	1.26
8. unserved energy, Mw	needle-1			17	17	16	16	16
	peak-1			0	0	0	0	0
	int-1			0	0	0	0	0
	base-1			0	0	0	0	0
	needle-2			15	15	14	14	14
	peak-2			0	0	0	0	0
	int-2			0	0	0	0	0
	base-2			0	0	0	0	0
	net energy unserved			6	6	6	6	6
9. unserved energy costs		w(u)						
	needle-1		1	193.9	199.5	205.2	211.0	216.9
	peak-1		0	0.0	0.0	0.0	0.0	0.0
	int-1		0	0.0	0.0	0.0	0.0	0.0
	base-1		0	0.0	0.0	0.0	0.0	0.0
	needle-2		1	58.7	60.3	62.0	63.7	65.5
	peak-2		0	0.0	0.0	0.0	0.0	0.0
	int-2		0	0.0	0.0	0.0	0.0	0.0
	base-2		0	0.0	0.0	0.0	0.0	0.0
	total unserved energy cost			252.6	259.9	267.2	274.7	282.3
10. voltage variation cost								
	needle-1							
	peak-1							
	int-1							
	base-1							
	needle-2							
	peak-2							
	int-2							
	base-2							
	voltage variation cost							
11. effective demand curve (in Mw)	needle-1			230	242	251	254	261
	peak-1			148	155	159	158	158
	int-1			112	119	125	133	138
	base-1			99	106	113	121	128
	needle-2			220	231	239	242	248
	peak-2			148	155	159	158	158
	int-2			100	106	111	118	122
	base-2			87	93	99	106	112
net gwh demand				1006	1064	1118	1173	1216
non-technical loss rate				10.00%	10.00%	10.00%	10.00%	10.00%
gwh sales				905	958	1007	1055	1095

Load Management

Two types of load management can be accommodated: indirect, tariff induced changes to the shape of the demand curve, and direct load control. To illustrate how direct load control options are incorporated, consider the data of Table 5, taken from a recent report on Load Management options in Costa Rica[22]. Assume that all of the targets are implemented over a three-year period, reaching 4.7Mw of peak reduction in the third year.[23]

The coincident peak reduction will in general be less, adjusted by the factor f(p) (see section 3 of Table 4). Moreover, some part of the load eliminated during the peak will be shifted to off-peak: for example, electric water heaters switched off during the peak hours will switch on immediately after the cut-off period to maintain thermostat settings: we assume some part f(s) of the peak load reduction is shifted[24]. It should be noted that the benefits to the target facilities is reflected by lower tariffs, as calculated in section 14 of the demand module.

22 "Costa Rica: Load Management Project: Phase I; Planning" Report by Haglar-Bailly to USAID, April 1988.

23 These are of course industrial and commercial sector facilities: we include them in the residential sector module solely for the illustrative purposes of this report.

24 However, a 1kw reduction in peak load does not result in a 1 kw increase in off-peak: rather, the increase in the off-peak period will be adjusted by the ratio of the widths of each block. This ensures that the *energy* reduction in the peak is offset by an equivalent increase in energy in the off-peak.

Table 5: Direct Load Control in Costa Rica

plant name	peak demand,Kw	reduction Kw	cost to plant,$
Ticatex	2462	164	8000
Conducen	606	146	6000
Hotel Cariari	399	50	3000
Campoania Numar	960	100	6000
Cerveceria Costa Rica	1500	50	8000
Fab.Nac. Liquores	576	60	2500
Fertica	5493	1700	20000
Fab. Heilo Gutierrez	182	15	2000
Empacadora de Carnes	1316	375	10000
Hotel Tamarindo	300	25	2500
Productos Gerber	318	23	
El Gallito	806	150	2000
Befecicio Victoria	704	50	3000
Rigalit	1025	324	3000
Scott Paper	6000	1500	
Total	22647	4789	73500

Source: Haglar-Bailly, op.cit.

Tariff induced changes to the load curve are treated in a somewhat different fashion. The time-of-day tariff is specified in section 13 of the demand module for peak periods: the model has the ability to calculate what reduction in off-peak tariff is necessary to maintain overall revenue neutrality. Thus, in the example shown, revenue neutrality requires that if the peak tariff increases by 30%, off-peak tariff must decrease to 91.5% of the base value[25]

The impact of the differential tariff rate is specified in section 2 of the demand module: for the above changes in tariff, 2.8% of the peak load is shifted to the off-peak periods. The resulting impact on the evolution of peak demand is shown on Figure 15.

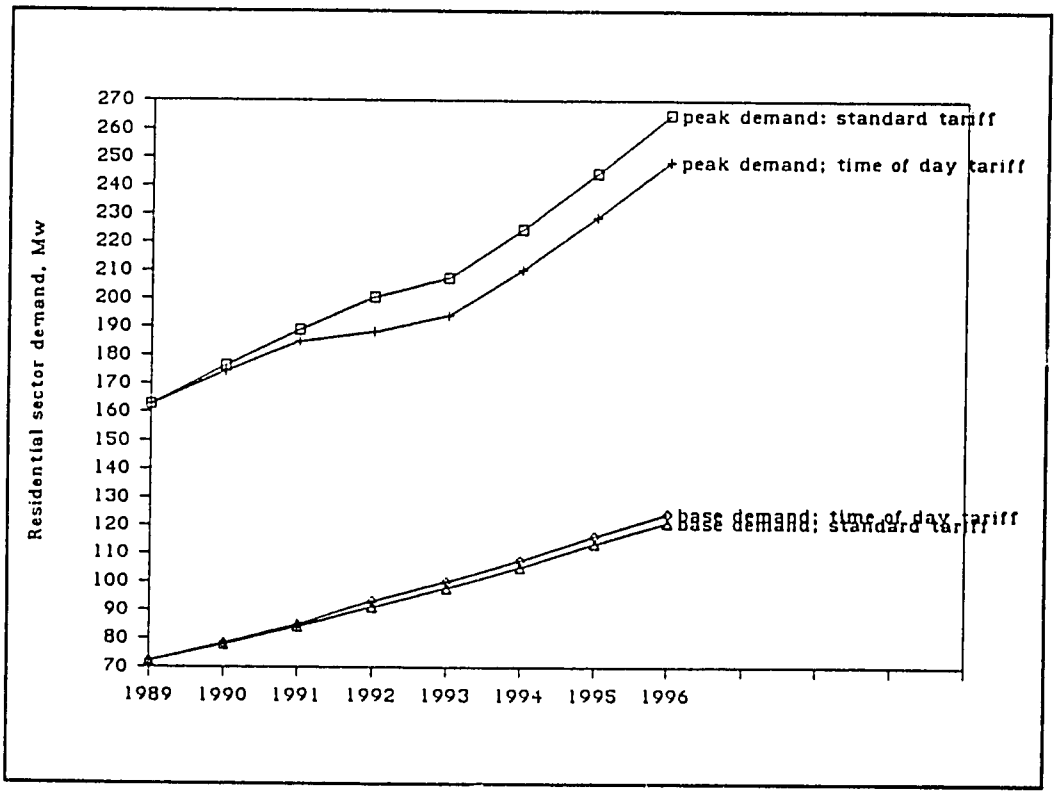


Figure 15: Load shifts resulting from time-of-day tariffs

25 If revenue neutrality is *not* required, then the corresponding formulae are simply erased.

Power Factor Correction

The simulation of the distribution/transmission system is done in terms of KVA rather than KW, since line and transformer losses and rated capacities are a function of the former rather than the latter. For each demand sector we therefore specify a power factor $\cos\theta$, from which the KVAR demand follows for given real power KW as

$$KVAR = KW \cdot \tan\theta$$

and hence KVA follows as (see Figure 16)

$$KVA = \sqrt{KW^2 + KVAR^2}$$

We next permit each demand sector to install power factor correction equipment, whose capacity is specified in terms of the KVARs it provides, say $KVAR_C$. The adjusted KVA demand, after the installation of power factor correction equipment, follows as

$$KVA_A = \sqrt{KW^2 + (KW \tan\theta - KVAR_C)^2}$$

In the default version of the model, demand charges (and hence utility revenues and consumer costs) are linked to KW demands. However it is of course a relatively simple procedure to introduce a demand charge based directly on KVA or KVAR loads[26].

26 For a discussion of some tariffs that directly penalize KVA, see e.g. S. Berg "Power Factors and Efficient Pricing and Production of reactive Power", Energy Journal,4,1983,p93-102

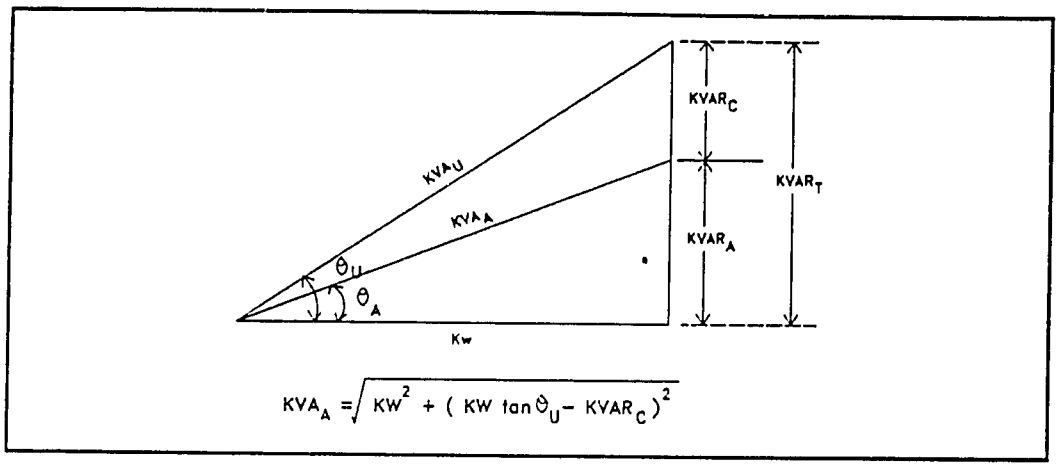


Figure 16: Power Factor Correction

Unserved Energy

The most common way of incorporating the cost of unserved energy in planning studies is to use the cost of generation from a small standby diesel generator. For example in the 1987 Pakistan Power System planning study, the cost of unserved energy used in the WASP-III model was calculated at 13.5 c/KWh. As noted in the report this cost is considerably higher than the average (or even the marginal) cost of generation in the grid, which means that the WASP optimization places a very high penalty on system availability.[27]

In the absence of more detailed information this is perhaps a not unreasonable assumption. However, in many countries much more is now known about the incidence, nature and costs of unserved energy. First, even if the cost of self generation is used as an upper bound, there are often very sharp differences in self generation costs as a function of industry and unit size, as illustrated on Table 6 which shows survey data from India. Second, it is recognized that the cost of outages is strongly dependant on the time of day, and whether the outage is planned or unplanned.

27 UNDP/World Bank "Power System Planning Study", 1987; see p. 32

Table 6 : Survey Findings on Captive Diesel Generators

		<100 kVA Establishments	100-999kVA Establishments	>=1000kVA Establishments
a.	Capital cost (Rs/kW)	3193	2763	2807
a1	Annualized capital cost	469	406	412
b.	Fixed Annual Operating Costs	1143	947	704
b1	(Rs/kW)	670	227	69
b2	Salary	82	85	47
b3	Routine maintenance	391	635	588
	Overhaul maintenance			
c.	Operating Parameters			
c1	Diesel gen. load ratio (fraction)	0.605	0.451	0.519
c2	Ave. Diesel cons. (lit/kWh)	0.2388	0.2386	0.2368
c3	Utilization (hrs/year)	1338.36	1782.7	2885.29
c4	Lube cons. (lit/hr)	0.2047	0.4078	0.5487
c5	Ave. Diesel gen. capacity (kVA)	64.7	214.3	960.2
d.	Variable Operating Costs (Rs/kWh	0.8277	0.8141	0.7673
d1	net)	0.7590	0.7585	0.7528
d2	Diesel use	0.0687	0.0556	0.0145
	Lube oil use			
e.	Installed Capacity (MW)	527.4	578.3	470.4
e1	Haryana	115.7	147.1	99.8
e2	HP	1.0	19.3	-
e3	JK	8.9	15.4	-
e4	Punjab	106.8	115.8	97.0
e5	Rajasthan	71.5	105.4	-
e6	UP	173.5	120.6	228.7
e7	Chandigarh	0.5	1.0	-
e8	Delhi	49.5	53.7	44.9
f.	Net Generation (GWh)	404.0	440.7	658.9

a1 : Economic life time = 15 years; annual discount rate of 12%.

c. : Weighted average obtained from field survey data.

d1 : Assuming c.i.f. price of HSD is Rs. 2/litre, to which a premium of 25% is added to reflect the scarcity of foreign exchange. Further, assuming that HSD is transported over a distance of about 1000 km. at a cost of Rs. 0.599/t-km; and density of 0.87 kg/litre.

d2 : Assuming the cost of lube oil is Rs. 10/litre (including c.i.f. price, shadow price of foreign exchange and transport cost).

Source : TERI (1987), op cit, Ref. 4.

Indeed, there is a growing literature on the subject of the costs of unserved energy of which ELECTROPLAN can benefit. For example, a study for Costa Rica shows that the cost of unserved energy to households is a function of wage rate and the time of day[28]:

Eq.[3] $OC = -1.8 + 0.781\, w\, d$

where OC is the outage cost for residential consumers for an outage of d hours, occurring between 8 and 9 p.m, and w=wage rate of residential consumers in colones per hour. Outage costs outside the peak hours were estimated at zero, with the residential outage cost function as shown on Figure 17.

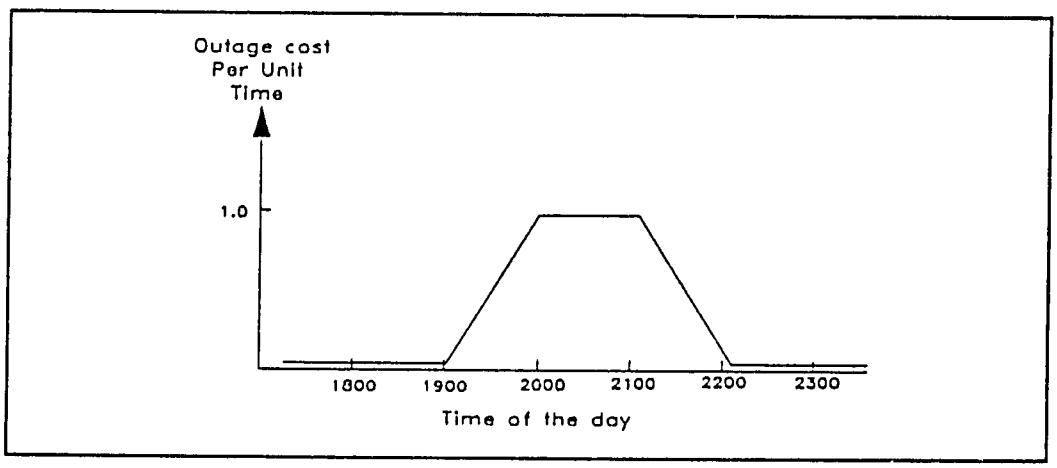


Figure 17: Costs of unserved energy, Household Sector of Costa Rica

(Source: Munasinghe op.cit.p.65)

Such an outage cost function is readily incorporated into ELECTROPLAN, since the linearisation of the load duration curve into four blocks permits definition of a "needle peak" representing one hour per day. Blocks of Table 4 illustrate the implementation of this scheme.

28 M. Munasinghe "Optimal Planning, Supply Quality and Shortage Costs in Power Systems: Case of Costa Rica", The Energy Journal, 9,Special Issue on Electricity Reliability, p.43.

4.5 The Distribution System Module

Most planning models have an extremely primitive representation of the distribution system, for which an aggregate quantity "losses" is generally presumed to suffice. At the other extreme are detailed distribution system models used by distribution planning engineers, that essentially model each and every distribution feeder. Clearly what is required is some compromise between the two, that is of sufficient detail to be able to capture the essential relationships between distribution system investment and technical performance without modelling each and every line and substation.

The integration of the distribution/transmission system into the demand and generation modules is shown on Figure 18. We show here three customer groups -- at low medium and high voltage-- and three voltage levels in the distribution system -- secondary and primary distribution, and transmission. While both can be extended as desired, the default version of the model makes a further distinction between urban and rural consumers in order to incorporate explicitly rural electrification programs.

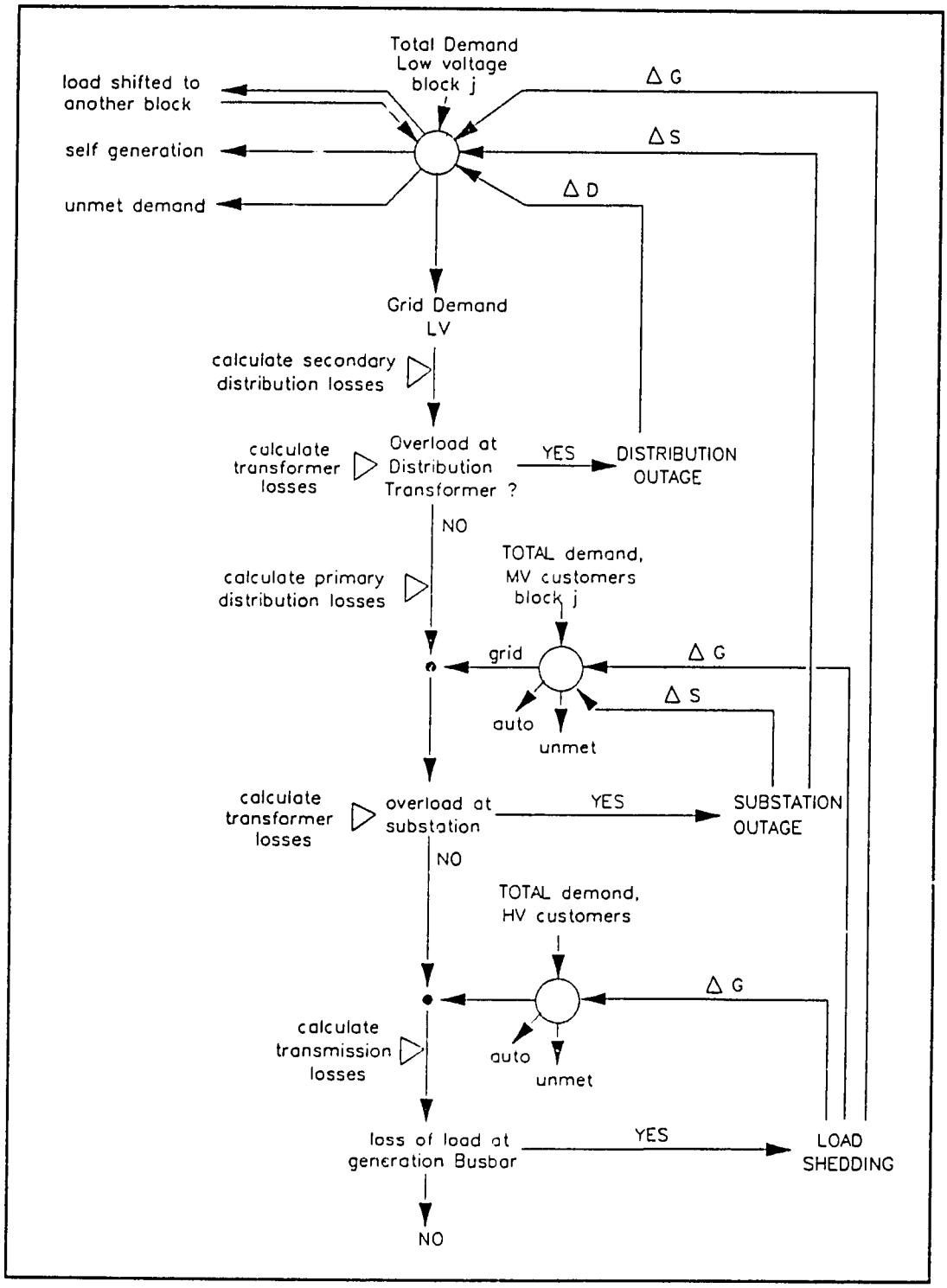


Figure 18: The distribution system model

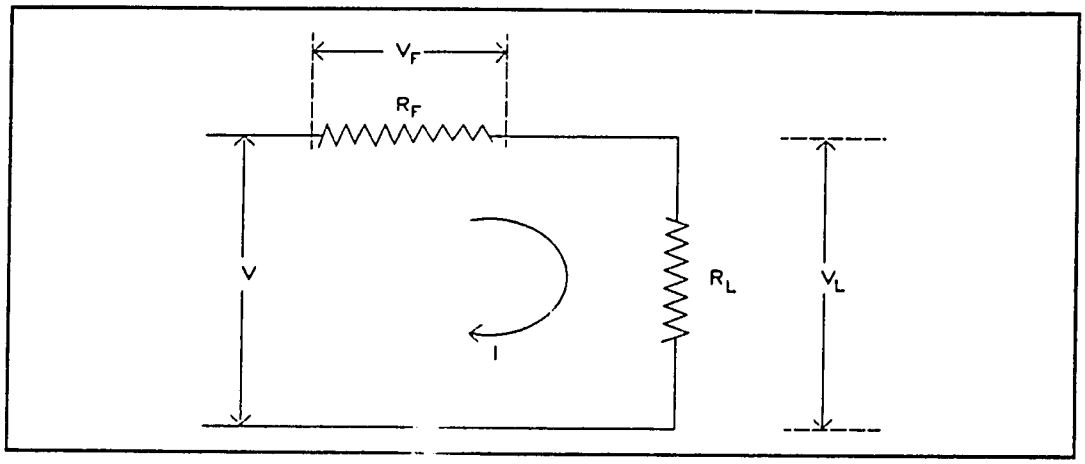


Figure 19: Distribution Feed · Calculations.

The calculations begin with calculation of losses for a typical secondary feeder (see Figure 19); the p: 'eeder calculations are then multiplied by the number of feeders in the sys :. The voltage drop across the (per feeder) load, V_L, is given by

$$V_L = V - V_F$$

where V is the voltage across · output of the distribution transformer, and V_F is the voltage drop across . feeder. In turn, V_F is given by

$$V_R = I R_F$$

where I is the current, and R_F :he resistance of the feeder. But the current, in turn, is given by

$$I = L/V_L$$

where L is the customer load. : se three equations have 3 unknowns: I, V_F and V_L: some algebra will sl: ıe solution for V_F to be

$$V_F = \frac{V}{2} \pm \sqrt{\left(\frac{V}{2}\right)^2 - LR}$$

Experience indicates that on · ın safely reject the solution obtained by subtraction of the second term : ıd enter the LOTUS formula equivalent of

$$V_F = \frac{V}{2} + \sqrt{\left(\frac{V}{2}\right)^2 - LR}$$

into the appropriate spreadsheet cell.[29] Figure 20 shows the results of such calculations for LT lines in our sample problem.

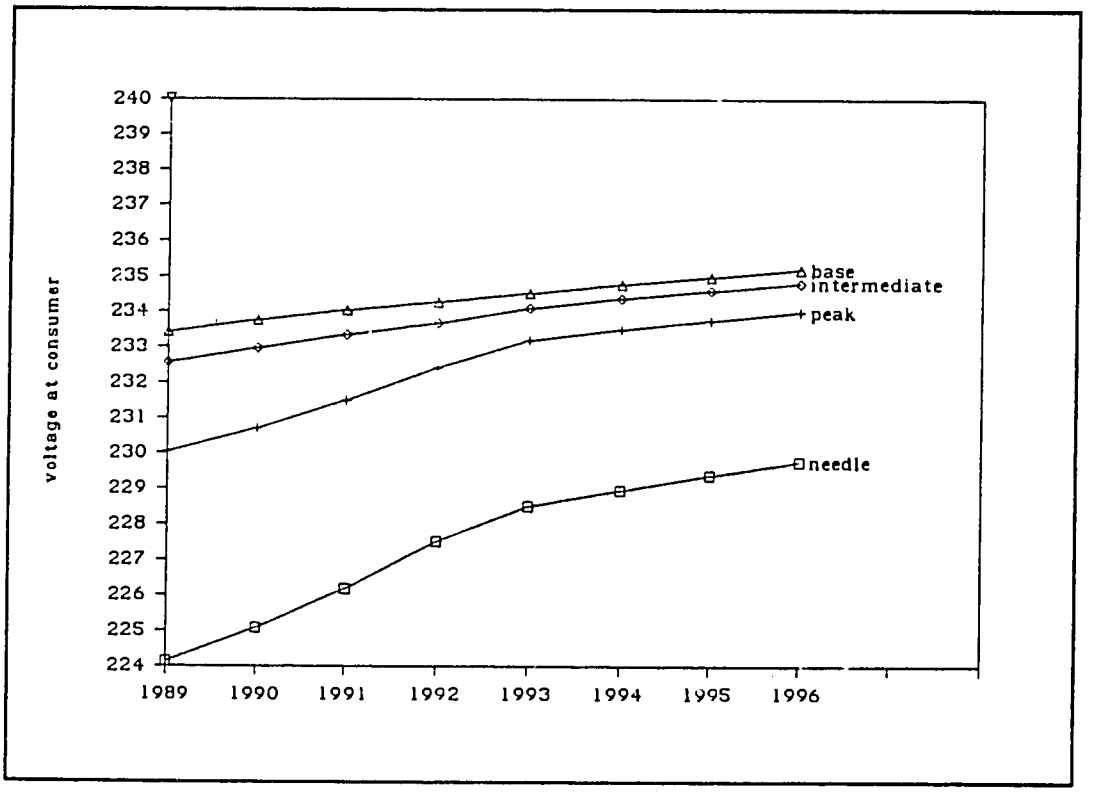


Figure 20: Calculated LT Voltages at the consumer

Given this calculation of line losses, and given the number of feeders per distribution transformer, the total load on the typical distribution transformer can be calculated. The distribution transformer can be assumed to suffer a failure if the load exceeds some stated percentage of the rated capacity. If such an outage occurs, some part of the demand cannot be met, which means

29 Under this assumption, note that as R -->0, V_F --> V, which is the desired result. Of course the second term can, in theory, be negative, with a complex root; but this case does not occur in practice even where line losses are as much as 20%.

that in the next iteration some part of the original demand cannot be satisfied by the grid: the process is repeated until such time as the outage condition no longer occurs. Suppose that the unconstrained system demand in the i-th block, of width t_i hours/day, is D_{Ui}, and that the demand that no longer causes the outage condition at the distribution transformer is D_{Ei}. Then the unserved energy is

$$E_N = \sum_i (D_{Ui} - D_{Ei}) t_i$$

Such calculations are repeated for other consumers -- medium voltage consumers are assumed connected at the primary distribution voltage, high voltage consumers at the transmission voltage. Finally, if the load at the generation busbar exceeds the generation capability, load shedding is assumed to occur, and the deficit is passed back to the consumer groups.

This raises the question of how the generation deficit is allocated among consumer groups. The most obvious is to allocate the load to be shed in such a way that the total costs to the system are minimized, which means passing the shortage to the group with the lowest incremental outage cost. Since we keep track of the total cost to each consumer at each stage of the calculation, this is readily done. Other approaches, such as allocation of curtailments in proportion to load, are readily incorporated.

The end result is a set of grid demands, outages, generation and load shedding requirements that is complete and consistent. Fortunately, convergence is in fact attained fairly rapidly, requiring typically some 20 iterations. Note that all sources of losses are explicitly calculated -- including iron and copper losses in distribution transformers, line losses at each voltage level, as well as auxiliary and step-up losses in generation.

In this calculational scheme we are thus in a position to estimate the impact of all of the components of a rehabilitation and/or expansion of the distribution and transmission system, including power Factor Correction, reconductoring of distribution lines, transformer change-out, and changing the configuration of the distribution system (e.g. moving from extensive secondary systems based on large distribution transformers to a decentralized system with many small distribution transformers)

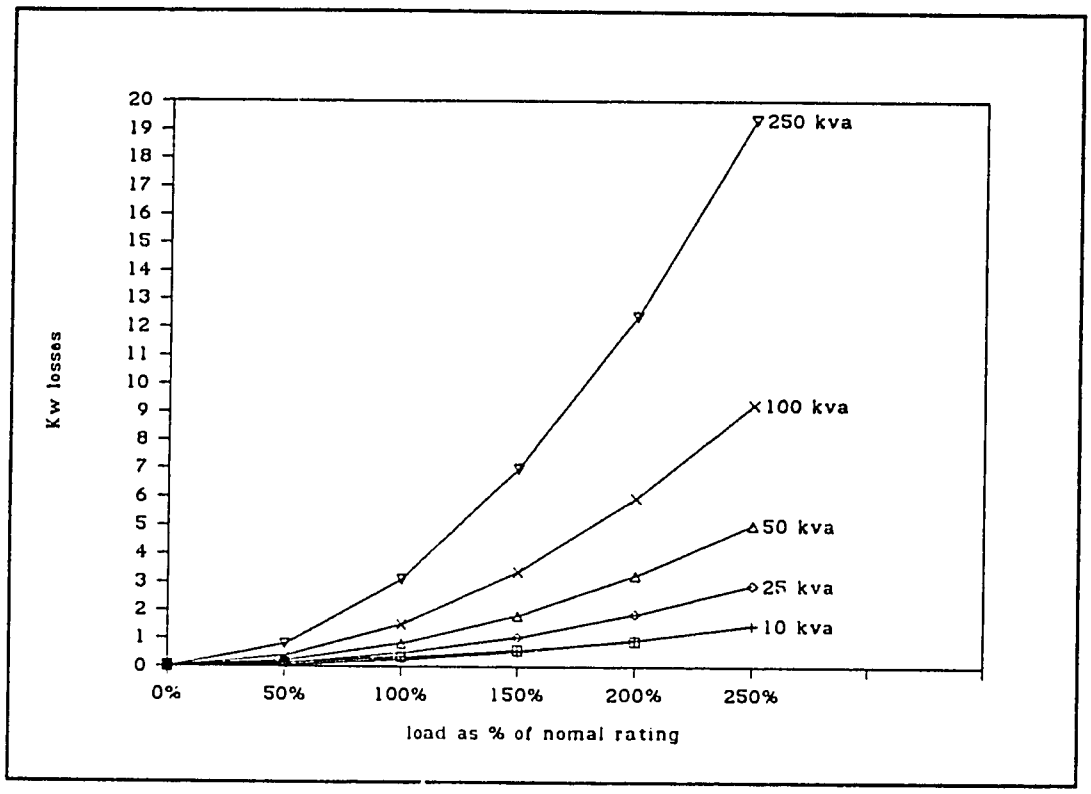


Figure 21: Copper losses in distribution transformers

In order for this approach to be practical, valid cost and loss functions must be available for each of these components. Fortunately there is sufficient available engineering information available for such functions to be estimated relatively easily. For example, on Figure 21 we show the basis for the calculation of copper losses in distribution transformers, extracted from World Bank data.[30] To these curves we have fitted a non-linear regression function that can be used directly in the appropriate spreadsheet cells to calculate losses as a function of the kva rating of the transformer and actual load imposed.

30 M. Munasinghe and W. Scott "Energy Efficiency: Optimization of Electric Power Distribution Losses", World Bank Energy department Paper #6, July 1982. To these copper (load dependant) losses must be added the so-called no load "iron" losses