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IMPACT OF CONSTRUCTION DELAYS ON THE RELIABILITY OF A HYDRO SYSTEM
A BRAZILIAN PLANNING EXPERIENCE

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Résumé

This case study deals with system planning adjustments to construction delays caused by financial restrictions, discussing the effects of such delays on the reliability versus cost function. It is based on the Southeast/South Brazil expansion plan (45/70 GW capacity in the late eighties/early nineties) and points out some problems peculiar to predominantly hydro systems. From the point of view of reliability, generation and transmission are treated in an integrated manner by a probabilistic approach. Pertinent features of the methodology used are presented.

Keywords

Brazil, Reliability, Hydropower, Power System Planning.

1. Introduction

Brazil has experienced sustained growth rates of the order of 10% per year in electric energy consumption during the last 30 years [1]. The generation output in 1981 was of the order of 140 TWh (95% of which produced in hydroplants) for an installed capacity of some 30 GW (85% hydro).

This predominant use of hydro resources associated with the continental dimensions of the country has led to intensive capital investments to meet such fast increasing market requirements, which are presently at the level of US$ 5 billions a year and represent around 10% of the country's fixed capital formation. Until the late seventies no restrictions of financial, ecological or any other nature represented a systematic barrier to the commissioning of major generation and transmission facilities on schedule.

However, from 1979 on, the electric utilities started to face difficulties in obtaining financial resources to meet an investment program that simultaneously included long maturation facilities such as Itaipu (12 600 MW) and Tucuruí (4 000 MW) hydroplants, Angra dos Reis nuclear units (2 600 MW), long regional interconnections (6 000 km of transmission lines of 500 kV and above) as well as the intended replacement of 1 300 MW of oil-fired thermal plants until 1985. These circumstances resulted in a concentration of financial restrictions in the period 1981-83, yielding a policy that aims at completing the works under way and restraining the beginning of new ones - previously foreseen and intended to assure the market supply in the second half of the eighties. As a consequence there arises the need to identify the impact of re-programming new facilities upon the security levels of supply, establishing a relationship between those and the reduction to be imposed on investments.

Within the above mentioned context, the purely deterministic criteria for system dimensioning become difficult to use, for they ascribe that a certain level of performance has to be obtained under situations that simulate the occurrence of credible events. Such situations could reveal themselves excessively severe either as a whole or under specific circumstances of the stage of system evolution. Through probabilistic techniques, it is possible to simulate a rather ample universe of situations, each one contributing with its own weight to establish the level of system performance, yielding more information for the decision-making process. In addition, this approach allows generation and transmission systems to be dealt with in an integrated manner.

A minimum knowledge of the characteristics of the Brazilian generation/transmission system is important for a discussion centering on the use of probabilistic or deterministic criteria.

The fact that generation is predominantly hydraulic in Brazil implies that:

a) the capital investment is concentrated and basically associated with the needs of energy production; once these energy requirements are met, the complementation of peak requirements is done at low incremental costs;

b) the availability of energy offer is a function of the hydrological conditions;

c) the availability of peak offer is a function of the available head;

Other characteristics that have consequences on the transmission system and influence the reliability of the load supply are:

d) the majority of plants is located far from load centers;

e) a great number of plants present high installed capacity (over 1 000 MW) and in some cases have units of large size;

f) the capacity of peak modulation is low in the main load centers, which have to import from distant hydro plants.

The transmission system thus requires large investments since:

. it is predominantly composed of long lines (over 300 km for voltages above 230 kV);

. it needs frequent reinforcements and resorts to expensive reactive compensation for transient stability and voltage control reasons.

Since the transmission system is responsible for a large part of the peak supply, it becomes of critical importance for the system performance that these peculiarities are taken into due account in its dimensioning. Thus the model for the analysis of the generation/transmission system must necessarily appraise:

a) the risk of not supplying the loads in terms of energy - this depends upon the probability distribution of the amount of water available in each plant of the system;

b) the risk of not supplying the loads in terms of peak - this results of the combination of the following probability distributions:

. available head, which is a function of water availability in each plant;

. available generating units, taking into account planned and forced outages;

. available transmission capacity, taking into account planned and forced outages of its components.

In this paper, 45/70 GW system configurations portraying the evolution of the interconnected Southeastern/Southern grids in the period 1987-92 are focused. Such configurations start from a pre-established reference based on deterministic criteria prevailing in current planning practice in Brazil and are modified taking into account financial restrictions. The presentation of this case study of a predominantly hydro system tries to provide an insight into relevant aspects involved in this subject through the identification of the effects of delays on the reliability versus cost function.

2. The Approach

2.1. Evaluation of Energy Availability in a Predominantly Hydro System

The energy production of a hydro system depends on the amount of water available at each plant of the system. Since it is impossible to have a prior knowledge of future streamflows, it is common practice to assume that the sequence of flows observed in the past will be repeated in the future. With this assumption, the expansion of the system is planned in such a way that the growing energy consumption is always less than the firm energy. The latter is defined as the maximum energy demand which the system can meet if the worst drought recorded in the past (critical period) happens again. This is the basis for the so called deterministic planning criterion. There are several objections that can be raised against this approach, such as:

a) The planner is unable to determine the reliability of the system. If the critical period obtained from the records is particularly severe, it is likely that the unknown probability of deficit is too low. In this case the deterministic planning criterion would lead to overdesign and consequently inadequate allocation of economic resources. On the other hand, if the unknown probability of deficit is too high, the planner is taking higher chances of failure than he should;

b) The firm energy is a quantity which depends on the length of the streamflow record: the longer the record, the smaller the firm energy one can expect. Furthermore, if a long sequence of flows is split into sub-sequences, the associated "firm energies" will be quite different from each other.

An alternative to the deterministic planning criterion is to assume that the streamflow record is just a realization of a stochastic process. The engineer's task is to identify the process and estimate its parameters. Once this is done, he is able to synthetize many streamflow series, each one as likely to occur as the recorded one.

The synthetic series can be used as input data to a model which simulates energy production under different hydrological conditions. A set of results is obtained, rather than the single output one gets when just the recorded series is used as input. In this way, the stochastic model allows to extract more efficiently the information available in the recorded series.

The simulation model can be developed with different levels of representativeness of the system. For the sake of energy studies, it is sufficient to assume that all the hydro plants are represented by a single ideal plant downstream from a reservoir of energy (rather than water), the so called equivalent reservoir. The thermal plants are lumped according to operation cost and their use aims at complementing the available hydraulic energy. The synthetic series of inflow energy to the equivalent reservoir are produced by a stochastic model which has been tested for several case studies of system expansion [2].

The output of most interest in this particular simulation is the probability distribution of the energy content in the equivalent reservoir. Each value of this random variable can be associated to a vector whose components are the hydraulic power available at each plant of the system [3].

Table 1 shows an example of this probability distribution, dividing the range of stored energy into five intervals. The total available power is also shown for each interval.

The simulation model for the equivalent reservoir operation also gives the average energy deficit due to water shortage and the average thermal production, both being relevant indicators for the comparison of generation expansion alternatives.

Storage level of the reservoir (%)	Total hydraulic available power (MW)	Probability (%)
⩾ 80	44 130	49
60 – 80	44 120	30
40 – 60	43 640	10
20 – 40	42 570	6
⩽ 20	40 620	5

Table 1 – Probability distribution of stored energy and total available power in January 1988.

Available thermal power: 2 110 MW (coal), 1 870 MW (nuclear)
Maximum demand: 37 870 MW, maximum stored energy in the equivalent reservoir: 95 TWh

2.2. Evaluation of Availability of Generating Units and Transmission System

In the evaluation of the final reliability of the load supply it is necessary, in addition to what was mentioned in item 2.1 , to consider the availability of the generating units and major transmission system components, such as lines and transformers, taking into account their planned and forced outage rates.

The evaluation of the impact of these availabilities in the reliability indices is done through a model based on the Monte Carlo method, whereby the generation/transmission/load system is simulated hour by hour along the period under study [4].

In the simulation, the unavailability of the generating units is identified on the basis of the actual forced outage probability for each type of machine, whereas the units committed for maintenance according to the planned rates are previously excluded from the possible generation dispatches.

The hydraulic availability in terms of peak is identified plant by plant, and within each plant unit by unit, by the series of values of available power and its associated probability, as mentioned in item 2.1.

The transmission system is identified by means of the configuration foreseen for each period under study, eventually altered by the components under maintenance on the basis of the planned rates; furthermore each component is assigned a forced outage rate. The loading limit of each component is pre-established and at each simulation it is checked that such a limit is not surpassed.

The load is represented by a daily curve conveniently discretized in three steps corresponding to the peak, intermediary and light loads levels. The week is represented by five identical working days plus a week-end with reduced load. Such a load configuration is kept constant during a semester, which is thus the basic period of analysis.

Each simulation starts with the extraction of a configuration of the generation/ transmission/load system on the basis of the availability of each generating unit and component of the transmission system. Then the performance of this configuration is worked out by the model. When a certain amount of generation becomes unavailable, the appropriate load/generation balance is rebuilt through the dispatch of units in reserve. Such a redispatch is carried out respecting the limits of hydraulic availability and giving priority to the use of the reserve of the area affected by the outages. If the load/generation balance is not achieved by means of extra generation, then the load is shed in the amount necessary to restore the desired balance, preserving whatever part is considered priority.

When some component of the transmission system is unavailable or when there is a redispatch among areas, the loading of each network component is checked resorting to a simplified load flow computation. In case a component is overloaded, a new generation dispatch is tried. This redispatch is based upon optimizing relief techniques, taking into account the existing reserve.

In case it is impossible to eliminate the overload, the load is shed in the amount necessary to bring back the affected components to the pre-established limits. This shedding is done using optimizing techniques and preserving the loads defined as prioritary.

At the end of a semester, several indices are produced in order to appraise the performance of the planned system.

The first index is the risk of load shedding, evaluated as the ratio between the expected number of hours along the period considered on which any amount of load is shed and the number of hours in the period.

The second index is the energy not supplied in the period, which can be expressed for instance in MWh or as per unit of the total energy demand in the period.

A third index could be the amount of energy redispatched in the period which reflects to a certain extent the degree of difficulty in operating the system.

Once the ability to measure the reliability of the system is established, the correspondence between reliability level and system cost can be worked out for different configurations.

2.3. Relevant Demand Aspects

In the case of a predominantly hydraulic system the energy state of the system is determined not only by previous states given by the history of streamflows and system operation, particularly with respect to its reservoirs, but also by demand evolution. In fact, when analysing supplying conditions for a certain year it is not enough to have the demand level for that year: it is necessary to know how the demand evolves to reach that level.

Ideally demand forecasts should treat the power market as a stochastic process. In this way, instead of a single forecast, credible demand trajectories and the associated probabilities should be considered. The probabilistic parameters related to the existing demand forecast have not yet been properly evaluated and assumptions for the sole purpose of this paper seem unappropriate. A practical procedure would be to perform a sensitivity analysis of the results with respect to the demand forecast. For this, other forecasts with different growth rates could be considered in addition to the basic one.

In the Brazilian system it is not possible to identify a typical day which would correspond to the annual peak demand. The various regional systems grow at different rates and according to different patterns along the year. However, in global terms it is possible to approximate the evolution of the maximum monthly peak demand by a growing curve between January and June and a constant value between July and December. In order to reduce the computational work required this profile can be simplified by considering only a constant value for each semester. On the other hand, energy comsumption was considered to be continuously growing along the year, the trajectory being composed of average monthly values.

3. Cases Studied and Results Obtained

The formulation of expansion alternatives is done on the basis of long term studies with a 30 year horizon. These studies take into consideration the market forecast of the different electrical regions, their internal power resources along with competitive interconnections, aiming at minimizing the cost of the generation/transmission program. In this way the facilities tend to be developed in an economic sequence, deviations being due to constraints imposed by policy goals that exceed the objectives of the utilities such as technology innovations or support of important sectors of the economy (e.g. nuclear industry, d.c. transmission, coal mining) as well as the human and financial capabilities of the major utilities involved in the generation/bulk transmission expansion. The systematic use of financial restrictions in the formulation of expansion alternatives has not ever been an established planning practice.

The expansion plan for Southeast/South Brazil used here as reference was tailored to suit a market growing at a rate of 10.7% a year in the period 1980-84 and 8.4% a year in the period 1984-92 - an average of 9.1% from 1980 to 1992. Such an alternative assumes an electrical energy market without restrictions to growth and a construction schedule of new plants and transmission trunks without financial restrictions. It includes plants already under construction to be commissioned until 1985 whose investment disbursements cannot be significantly altered. On the other hand, there are 32 new plants to be commissioned until 1992, 9 of which present heavy investments in 1981-85. Financial restrictions during this period will delay the beginning of construction of some of these 9 plants, whose influence on the reliability of the supply will show up from 1986 on.

Based on the reference program, named Alternative I, two additional alternatives are built, assuming the same market forecast and the following financial restrictions in 1981-85;

Alternative II: moderate financial restriction. An inspection of a cost-benefit analysis for the nine plants previously referred has led to the choice of delaying the beginning of construction of one of them for two years, of six of them for

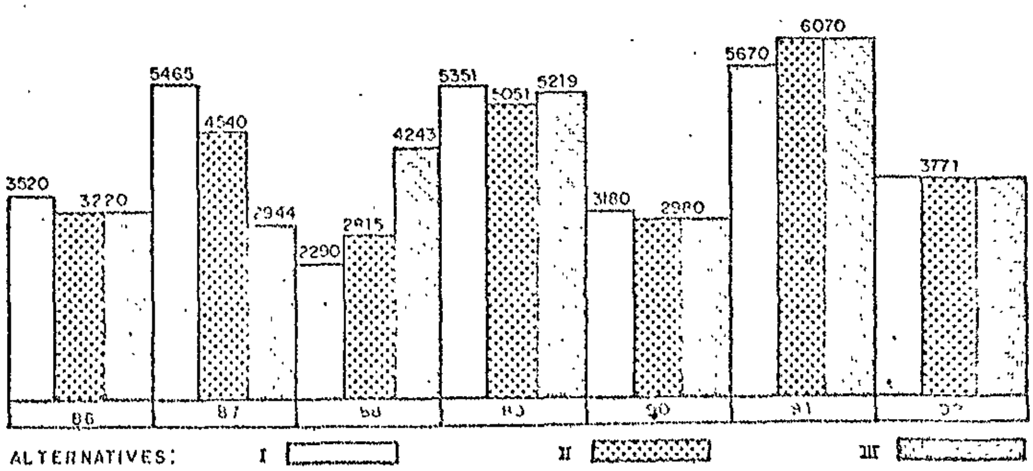

Figure 1 - Installed capacity increments in MW (1985 System: 38 194 MW)

one year and keeping the original schedule of two of them.

Alternative III: strong financial restriction. In addition to Alternative II the beginning of construction of the two remaining plants is postponed for one year.

Figure 1 shows the installed capacity increments for the three alternatives in the period 1986-92. At the end of this period Alternatives II and III still have less 800 MW installed capacity than Alternative I.

Figure 2 shows the evolution of the annual investment differences of Alternatives II and III in relation to the reference Alternative I. Investment reductions up to US$ 500 millions in a year can be observed in the period 1981-85, a figure that represents approximately 10% of the overall annual investment of the electric utilities.

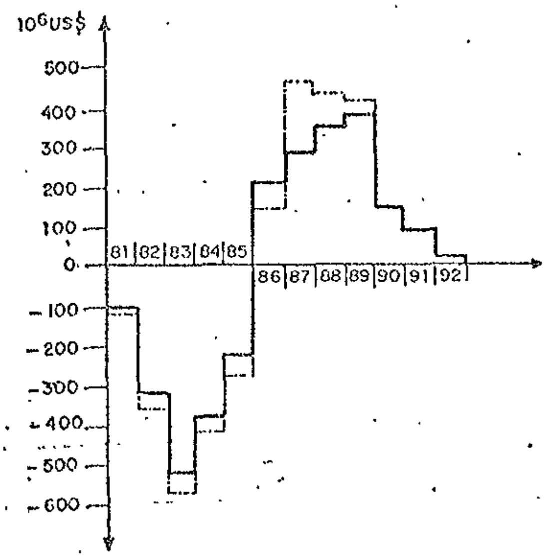

Figure 2 - Annual investment differences
(————): Alternative II - Alternative I
(-------): Alternative III - Alternative I
Note: Differences beyond 1992 are negligible

In establishing Alternatives II and III the possible reductions of investment in the transmission system were disregarded. In fact they are not so important in comparison with those related to power plant delays, because most of the plants delayed do not need a dedicated transmission system, being inserted with minor reinforcements in the grid that will exist at that time. The configuration of such grid was indeed established already taking into consideration future plant additions, some of those being delayed in Alternatives II and III. On the other hand eventual postponement of some major segment of the planned transmission network would be unfeasible, because their role is already essential to the load supply under normal operating conditions.

Table 2 presents the annual evolution of the probability that there is any energy curtailment due to lack of water, as well as the expected average values of energy not supplied and thermal production requirements expressed in percentage of annual energy demand.

It should be noted that the average of the annual probabilities of energy curtailment from 1987 to 1992 is 3.0% for Alternative I, roughly meaning that an energy shortage is expected to happen in average every 33 years. This alternative was planned on the basis of the deterministic criterion of firm energy derived from a 40 year streamflow record. The return periods for Alternatives II and III are significantly lower: 23 and 19 years.

The expected values of energy not supplied shown in Table 2 were calculated taking into account all the synthetic series generated, including those with no deficit. The expected energy not supplied conditioned to the occurrence of deficit can be derived dividing the previous values by the corresponding probability of deficit. For instance, in the year 1987 of Alternative III such a figure would result equal to 10% of the energy demand, which identifies more clearly the amount of energy to be curtailed.

Still from Table 2 it can be seen that Alternative III should require more fuel than Alternative II, which in turn should require more than Alternative I: the delay in the construction of hydro plants will inevitably result in increasing expenses with thermal plants in the future.

The expected thermal production corresponds to capacity factors smaller than the maximum annual value usually considered for thermal plants, which is around 70%. For example, for Alternative III in 1988 the expected capacity factor is only 48%, despite the high expected energy curtailment. In fact, when there is plenty of water in the reservoirs, thermal energy production would be unnecessary. On the other hand, when the available water is insufficient, thermal units are set at their maximum. In other words, increasing the use of the available thermal plants would not result in a reduction of the energy deficit and the only consequence would be to increase the spillage of the reservoirs.

Table 3 presents the indices related to the reliability of load supply as affected by possible lack of power. It shows the percentage of expected hours during which some load shedding will be necessary for this reason and the related energy not supplied.

The percentage is referred both to total annual hours (8760) and to peak hours (780). It is relevant to note that almost all load shedding are concentrated whitin the peak hours, the probability of any lack of power occurring during the off-peak period being minimum.

The probability values referred to the peak hours identify more clearly the difference in quality of load supply between the different alternatives. In particular the reliability of Alternative III seems very poor in 1987 and 1988 when loads are expected to be shed, scattered around the system, in about 60% and 30% of the peak hours respectively.

Comparing Table 3 with Table 2 it is important to note that in the years on which greater energy curtailments are expected, more frequent load sheddings due to lack of power are incurred.

This correlation can be explained by the

Year	Energy not supplied						Expected thermal production (% of energy demand)		
	Probability (%)			Expected average value (10^{-3} x p.u. of energy demand)					
	I	II	III	I	II	III	I	II	III
87	4.5	5.8	5.9	3.8	5.8	6.0	5.2	5.9	6.4
88	3.2	5.1	6.7	3.0	4.6	6.4	5.0	6.2	7.3
89	3.1	4.5	5.9	2.7	3.9	4.9	6.0	7.1	7.4
90	3.1	4.2	5.4	2.7	4.1	4.9	6.4	7.4	7.6
91	2.2	3.3	4.0	1.7	2.7	3.2	9.2	10.1	10.2
92	2.1	3.1	3.4	1.6	2.3	2.5	9.5	10.0	10.1

Table 2 - Energy not supplied due to lack of water and thermal production for Alternatives I, II and III

Year	Expected hours with load shedding (%)						Associated energy not supplied (10^{-4} x p.u. of energy demand)		
	Referred total annual hours			Referred to annual peak hours					
	I	II	III	I	II	III	I	II	III
87	1.1	2.5	5.2	12.4	28.1	58.4	4.9	12.1	22.9
88	0.7	1.7	2.6	7.9	19.1	29.2	2.8	7.4	11.6
89	0.5	1.1	1.2	5.6	12.4	13.5	1.5	4.6	5.7
90	0.5	1.1	1.2	5.6	12.4	13.5	1.3	4.4	5.2
91	0.4	0.9	1.0	4.5	10.1	11.2	1.2	3.1	3.7
92	0.4	1.0	1.1	4.5	11.2	12.4	1.2	3.0	3.5

Table 3 - Risk of load shedding due to lack of power and associated energy not supplied for Alternatives I, II and III

dependence of the peak capacity hydraulically available to the energy stored in the reservoirs as pointed out in 2.1.

It is worth noting that lack of energy and lack of power affect load supply differently. In the first case, the expected energy shortage - predictable well in advance - will give rise to a curtailment plan that dictates, possibly for months, load sheddings conveniently chosen over the daily load curve, peaking hours being the object of the first attempt.

In the second case, a lack of power capacity will result in a forced reduction of the reserve causing high probability of frequent and unpredictable load sheddings, mostly during the peak hours. Normally these sheddings will not last longer than the peak period. In fact the natural reduction of the load, along the daily curve, has the virtual effects of increasing the reserve, allowing the reconnection of the shed load areas.

The comparison between the energy not supplied due to water shortage in the generation system and due to the load shedding because of lack of power shows that the contribution of the latter event to the total amount of energy not supplied is relatively small, one order of magnitude lower than the former. On the other hand when establishing acceptable indices to guide the system planner, the distinct characteristics of the two events must be considered.

In economic terms, the three alternatives differ not only in investment cost (Figure 2) but also in the expected cost of running the thermal plants and the expected cost related to the energy not supplied (deficit). In this study, a fuel cost of US$ 9/MWh was adopted. The cost of deficit depends upon how one appraises the impact of deficit in the economy and in the lives of citizens. No deep investigation has ever been carried out in Brazil on this matter, reason why standard figures for the cost of deficit, existing for some countries, are not available. However the sensitivity of the total cost for each alternative can be evaluated for different assumptions regarding the unit cost of deficit.

In Figure 3 the present worth cost differences of Alternatives II and III in relation to the reference Alternative I are plotted as a function of the unit cost of deficit. It can be observed that Alternative I is economically more attractive than Alternatives II and III for unit costs of deficit exceeding US$ 0.33/kWh and US$ 0.24/kWh respectively.

Figure 4 shows another sensitivity analysis: the discount rate, previously set as 10%, is allowed to vary whereas the unit cost of deficit is fixed at US$ 1.0/kWh. The reference alternative is more attractive than Alternatives II and III for discount rates smaller than 22.5% and 27.5% respectively.

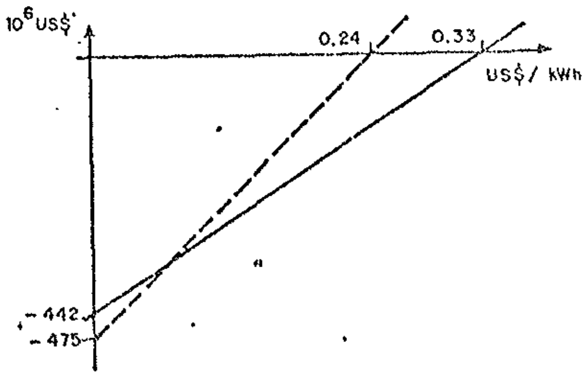

Figure 3 - Present worth cost differences between alternatives versus unit cost of deficit for a fixed discount rate of 10%.
(————): Alternative II - Alternative I
(- - - - - -): Alternative III - Alternative I

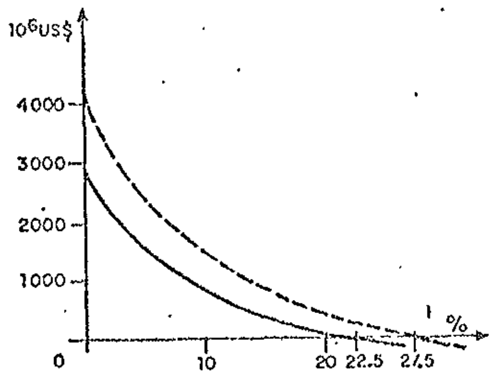

Figure 4 - Present worth cost differences between alternatives versus discount rate "i" for a fixed unit cost of deficit of US$ 1.0/kWh
(———): Alternative II - Alternative I
(------): Alternative III- Alternative I

A quick illustration of the market uncertainty effects was made assuming a constant annual growth rate of 9.1% for the period 1980-92 - lower than the 10.7% rate for the period 1980-84 and higher than the 8.4% rate for the period 1984-92 used wherelse in this paper - that allows to reach the same level previously forecast for 1992. The results of this analysis show that for Alternative III - strong financial restriction - the values of deficits and thermal generation are rather reduced, close to which can be considered a minimum. In this way the financial restriction as applied would result in a net cost saving, that is, Alternative III would be more economical than Alternative I, meaning that the reference expansion program should be reformulated.

Three other sensitivity checks are worth reporting. The first case refers to the influence of reservoir levels on load shedding due to lack of power. Year 1988 of Alternative III was tested assuming that any machine would be able to contribute with its rated power to the peak load supply. The results confirm that the effect of the hydraulic restriction - represented by reduction of the available head due to the drawdown of reservoirs - is very important, almost dramatic. In fact, the percentage of peak hours during which some load shedding occurs would decrease from 29% to 13%. It is interesting to note that in the hypothetical conditions considered the reliability indices of Alternative III would be not far from those of Alternative I.

The second case of sensitivity analysis refers to the influence of a different maintenance policy aiming at improving the poor reliability conditions of the peak load supply in the worst year for Alternative III, namely 1987. Assuming an unforced outage rate of 2% for the generating system, instead of the 4% previously considered, the percentage of peak hours with load shedding decreases from 58% to 19%, thus strongly increasing the reliability of Alternative III. It is worth noting that the value of 2% assumed for the unforced outage rate in this exercise cannot be considered a guaranteed value but only a goal to be reached during the two most critical years for Alternative III. It will probably be necessary to delay some major maintenance beyond 1988, implying a reduction of the reliability indices in those years.

The final case of sensitivity analysis illustrates a specific effect of system generating capacity on the reliability of peak load supply. In 1992, Alternative III differs from Alternative I because eight 100 MW generating units in one plant are still to be installed and because reservoir levels are lower, both facts deriving from construction delays imposed by financial restrictions. The assumption of this exercise was the increase of unit installation rate during the year 1991 so that Alternative III could have the same installed capacity of Alternative I in 1992. However the hydraulic conditions of Alternative III remain unchanged. In fact, the eight additional machines do not contribute to improve the energy state of the system; that is, no modification in the level of the reservoirs would occur. The outcome of these hypotheses is that the percentage of peak hours with load shedding in 1992 for Alternative III decreases from 12.4% to 7.7%. This value is still far from the 4.5% obtained for Alternative I, in spite of the same installed capacity. The result points out that the inertia of hydro systems due to inherent time lags in the refilling of reservoirs dictates the length of time necessary to recover installation delays, not only in terms of energy availability but also in terms of effective peak power capacity.

4. Conclusions

The probabilistic approach proved well adequate to compare different planning alternatives derived from construction delays due to financial restrictions allowing the integrated treatment of generation and transmission systems and the identification of cost x reliability relations.

Apart from the specific results related to the case studies presented in chapter 3, a few general conclusions related to a predominantly hydro system are given:

- The availability of peak power, specially in the presence of reservoirs, is influenced directly by the energy state of the system, since the latter and the available heads are closely related.

- The analysis of the cost x reliability relations for certain configurations of the generation/transmission system should take into account the path of the evolution of energy demand. Risk analysis of a certain year is based on the knowledge of the system's energy state in that year, which in turn is determined by operation previous to the year considered.

- Lack of water in reservoirs has a substantially greater effect on the amount of energy not supplied than the lack of power. One should note that each of these two components has different impacts on the system: lack of water can be predicted and a curtailment program with selective load shedding can be put into effect; lack of power is unpredictable and tends to occur at peak periods. In the latter case, in certain critical years, a special maintenance policy reducing unforced outages might allow a smaller decrease in the reliability incurred by a system affected by construction delays.

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