THE EFECTIVENESS OF DEMAND ELASTICITY IN COMPETITIVE HYDROTHERMAL SYSTEMS

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Abstract – In competitive hydro-based systems there is a strong incentive for Distribution Companies to contract 100% of their needs to avoid the well known price volatility of the spot market. Because the bilateral contracts are financial instruments, the load may automatically sells to the spot market any difference between contract and actual consumption. This means that, if spot prices are high, there will be an incentive for load reduction. This mechanism will allow the potential for load elasticity to be realized. The objective of this work is to analyze this issue, by comparing the tradeoff between giving incentives to customers to reduce their consumption when the spot prices are high and the actual benefit of this reduction to the Distribution Company in terms of revenues. Case studies with data taken from the Brazilian system are presented and discussed.

Keywords: Hydrothermal power generation, Price Volatility, demand elasticity, Risk Management

1 INTRODUCTION

Electric utilities all over the world have been undergoing changes in their market and regulatory structure. A basic trend in this restructuring process has been the replacement of traditional expansion planning and operation procedures, based on centralized optimization, by market-oriented approaches:

a) Generators bid prices for their energy production in a Wholesale Energy Market – WEM. Units are then loaded by increasing price until demand is met. Dispatched generators are remunerated on the basis of the system spot price, which corresponds to the bid of the most expensive loaded unit.
b) Instead of following an expansion schedule produced by a central planning agency, private agents are free to decide on the construction of generating units and to compete for energy sales contracts with utilities and individual customers. One of the key components in the private investment decision is the forecast of WEM spot revenues for each plant, which are then compared with the plant construction cost.

An important obstacle observed in the practical implementation of those market-oriented schemes in predominantly hydrothermal systems (such as Brazil) is the extremely high spot price volatility [3,5,7]. Given this volatility of spot prices, bilateral contracts play an essential role in the market design. Bilateral contracts in Wholesale Energy Markets (WEM) are purely financial hedges, which protect generators from low prices and, conversely, loads from high prices. In other words, the production schedule of each plant determined in the dispatch as well as actual consumption of each load is completely independent of the contracts that their owners may have registered with the WEM.

The fact that bilateral contracts are financial instruments allows the load to sell to the spot market any difference between its contracts and actual consumption. This means that if spot prices are high, there will be an incentive for load reduction, which would result in surplus generation that could be sold directly at the spot market. This may encourage the distribution companies to negotiate with their clients a reduction in their consumption in the peak hours to enable the load reduction in the high spot prices season. In exchange, the Distribution Company could offer progressive discounts in the consumer’s electricity bills according to the amount of reduction or other incentives.

However, the main question for a distribution company when attempting to adopt this strategy is to evaluate the tradeoff between the losses of a fixed reduction of revenues (due to discounts to consumers) coupled with loss of revenue on the interruption times and high revenues at the spot markets associated to the high spot prices scenarios, which have an stochastic behavior (influenced by hydrological conditions).

The objective of this work is to evaluate this issue in a hydro based system (where the spot price can reach high values but with a stochastic behavior) by means of risk management tools and utility functions, taking into account a risk-averse profile of the utilities. This work is organized as follows: section 2 discusses the price volatility of wholesale energy markets and hydro-based systems. Section 3 discusses bilateral contracts and its effect on revenue uncertainty. Section 4 presents how load may benefit from selling at the spot market the differences between its contracts and consumption. Section 5 evaluates alternatives for modeling the risk versus gain tradeoffs. Section 6 presents a case study for a Brazilian utility and section 7 concludes.

2 PRICE VOLATILITY IN WHOLESALE ENERGY MARKETS

2.1 The Problem of Revenue Uncertainty

An important obstacle observed in the practical implementation of market-oriented schemes in the energy industry is the uncertainty of revenues from WEM sales. Given that most of the investor's financial obligations are fixed (e.g. personnel, loan payment etc), this revenue volatility affects its financial balance and rate of return.

2.2 Price Volatility in Hydrothermal Systems

Spot price volatility in thermal-based countries is usually driven by load fluctuations, which are in turn temperature-dependent, equipment outages and fuel price variation. As a consequence, the volatility tends to be high in the short-term (daily or weekly basis) but lower in the mid-term.

In contrast, predominantly hydro systems such as Brazil's present a fairly small short-term volatility but extremely high mid-term volatility. The reason for the reduced short-term volatility is that system reservoirs can easily transfer hydro energy from off-peak to peak hours, thus modulating load supply and equalizing prices. The reason for mid-term volatility is that predominantly hydro systems are designed to ensure load supply under adverse hydrological conditions, which occur very infrequently. As a consequence, most of the time there are temporary energy surpluses, which imply in very low spot prices. However, if a very dry period occurs, spot prices may increase sharply, and even reach the system rationing cost. Due to reservoir storage capacity, these low-cost periods not only occur frequently but can last for a long time, separated by higher-cost periods, caused by droughts. This pattern is illustrated in Figure 1, which shows the observed short run marginal costs (US$/MWh) in the Brazilian South-Southeast system from January 1993 until August 1997.

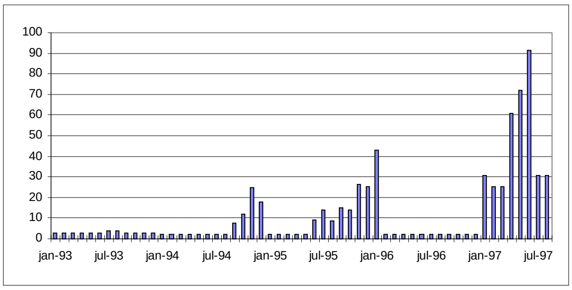

Figure 1: Brazilian System -Historical Monthly SRMC

We see in the Figure that the system SRMC was close to zero in 36 out the 56 months. We also see that the longest low-price period lasted for almost two years (21 months). This punctuated price evolution results in a very skewed price distribution in each stage. For example, Figure 2 shows the forecasted spot price frequency distribution for the Southern Brazilian system in January 2003. Fifty-one out of the 64 simulated hydro scenarios have prices lower than the average. Out of those, 26 scenarios have zero spot price. In contrast, there are a few scenarios where spot price exceeds $300/MWh.

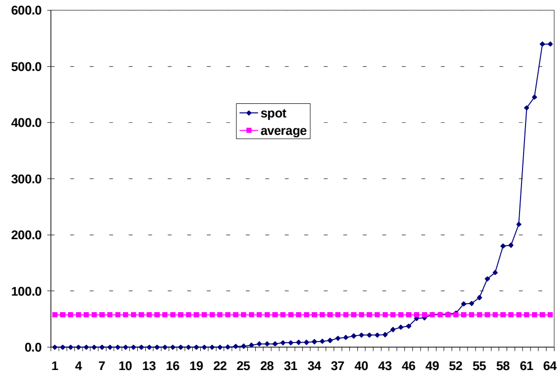

Figure 2: Spot Price Distribution – January 2003

3 BILATERAL FINANCIAL CONTRACTS

In order to hedge against the very high price volatility, generators and loads must sign bilateral contracts. The reason is that no generator or load can work directly on the spot market with such. Furthermore, in many countries there are rules establishing mandatory minimum level of contracts between generators and loads to assure supply reliability. In Brazil, for example, one of the basic rules is that at least 85% of the "captive demand" (load supplied by a distribution utility) should be covered by long-term contracts. The objective is to contribute to the financial feasibility of new generation and, thus, to an adequate reliability level. In other words, the demand for new contracts to cover load growth is the main "driver" for generation expansion, instead of economic signals from the spot market.

These contracts are financial instruments. For example, suppose that a generator/load pair has a 100 MWh bilateral contract priced at $35/MWh for hour t. When this hour arrives, the generator net revenue (R_g) and load payment (P_d) are given by:

$$R_g = \pi_d \times E_g + (35 - \pi_d) \times E_c \qquad (3.1a)$$

$$P_d = \pi_d \times E_d + (35 - \pi_d) \times E_c \qquad (3.1b)$$

The first term of expressions (3.1a-b) represents the generator revenue (load expense) resulting from the sale (purchase) of its production E_g (consumption E_d) in the spot market. The second term represents the contract settlement, where the load pays (generator receives) for the contracted energy amount E_c, valued at the difference between spot and contract prices.

Suppose that the actual generator production is 95 MWh, the actual consumption is 105 MWh and the system spot price, π_d, is low, for example, 10 $/MWh. In this case, the generator revenue resulting from the first term of expression (3.1a) – spot energy sale – is reduced. On the other hand, the second term is positive, that is, the generator receives an amount in addition to the spot revenue. In other words, the contract protects the generator against low spot prices. In turn, if the spot price is high (e.g. $50/MWh), load will spend a large amount of money purchasing energy in the "spot" market (first term of 3.1b). These expenses are partially compensated in the second term, which has a negative value. We thus conclude that the contract protects load from high spot prices.

4 THE ROLE OF LOAD MANAGEMENT

If one observe the expression (3.1b) from previous section, it can be stated that besides protecting the loads from high prices, the bilateral contracts may provide high revenues for these loads in these high prices scenarios.

The reason is that once the spot price is higher than the contract price, the lower this distribution company can set up its actual consumption, higher will be the difference between the actual energy contracted and consumption and this difference can be sold directly to the spot market at the spot price. In this case, the load will spend a few amount of money purchasing energy in the spot market (first term of 3.1b), which will be as low as the amount of actual consumption, and receive high revenue in the second term, which will have a negative value as high as the spot price value and load contracted. We thus conclude that, as bilateral contracts are financial instruments, the load can automatically sell at the spot market any difference between contract and consumption. If spot prices are high, there will be an incentive for load reduction. As the spot prices are usually high on peak times, the incentive will mainly occur on peak-demand hours.

However, in order to materialize the reduction of its actual consumption, the Distribution Company must establish any sort of a "deal" with its clients to reduce their consumption. Among many others [3,7,9], the most famous deal (which will be analyzed in this work) is a discount in their electricity bills increasing according to the frequency and amount of consumption to be curtailed. This would allow the consumers to value the reliability they would like to have in their energy supply, as done by many utilities [8,9].

The possibility of load flexibility for strategic usage of the saved energy is not an innovation. Through a modern system of consumers' monitoring (called *On Call Program*), Florida Power & Light (USA), promotes an imperceptible rationing, that makes the consumers save MUS$ 161 on average a year. Through a device of load control, programmed in agreement with the utility and consumer's interests, the electric network of the residences can be turned off partially or integrally, on the peak hours period or in previously scheduled hours [8]. Also, the possibility of load flexibility is very important to guarantee overall market efficiency [2].

5 FINANCIAL INSTRUMENTS

5.1 Risk Versus Gain Tradeoffs

The real world is a world of uncertainty. As observed in Section 2, in a hydro-based system the spot prices vary stochastically according to the system inflows and this results in very volatile incomes, thus representing a price risk: with variations in the price, there is a risk that the losses with incentives to consumers and load reduction will be higher than incomes from the spot market. Due to a "standard" risk-averse profile of the distribution companies, a risk-management approach to analyze the potential benefits of losses from the load management is recommended. An overview of the theoretical background for such analysis will be done next.

5.2 Representing Risk Versus Gain Tradeoffs

There is no universally agreed way to represent the gain versus risk tradeoff [3,5,6]. The usual risk-measures, such as regret or VaR, concentrate most of its analysis on the "bad" scenarios (e.g. 5%), for example, they do not take into account the revenues of the remaining 95% scenarios. In this work we will discuss the popular modeling approach through utility functions [5]. Utility functions take into account the whole range of scenarios by "translating" monetary revenues into risk-averse, risk-neutral or risk-taker "utility units".

5.3 Modeling Risk Through Utility Functions

The selection of the most adequate risk versus gain level depends on the individual agent's *risk aversion* profile. There are three usual classes to rank the risk profile of an agent: risk averse, risk taker and risk-neutral. Utility functions thus "translate" monetary revenues into "utility units", which in turn represent the agent's risk profile. For example, a risk-neutral investor would have a linear UF such as in Figure 3a. This means that a revenue increase has the same impact as a reduction; as a consequence, the expected utility is equal to the expected income. A risk-averse investor would have a concave UF, as shown in Figure 3b. In this case, the loss from a "bad" result is not "compensated" by the gain from a "good" result. Finally, a risk-taker would have a convex utility function, as shown in Figure 3c.

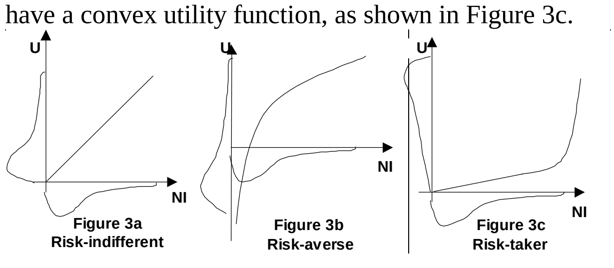

Figure 3: – Types of Utility Function

The objective is then to maximize the expected utility.

5.4 The Certainty Equivalent

Let R be the random variable that represents the revenue (in $); let U(R) be the associated utility function (in utility units). Next, let EU denote the expected value of U(R) over the possible values of R (in utility units). Finally, calculate the inverse of EU, $U^{-1}(EU)$ (in \$). This last value, known as "certainty equivalent", can be interpreted as the asset's "cash value". In other words, the asset owner would be indifferent (i.e. would have the same utility) between the options of receiving a *fixed* payment of $\$U^{-1}(EU)$ or receiving the stochastic revenues from power sales. Figure 4 presents the certainty equivalent for a concave utility function considering two random results x_1 and x_2.

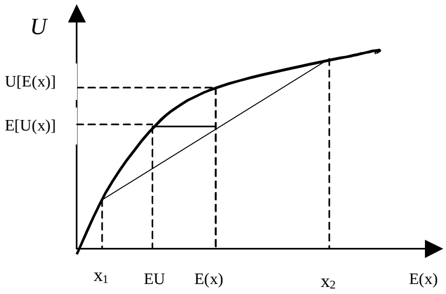

Figure 4: Certainty Equivalent

Observe that in this case the EU is smaller that the expected value of the random variable (E(x)).

6 CASE STUDY

To evaluate a real impact of the load management and associated risks, we have simulated the load retraction for LIGHT Distribution Company, located in Rio de Janeiro area (Brazil).

The objectives are twofold: first to determine a share of the utility's local market that would accept a load reduction and then compare, for this market share, the tradeoff between a fixed discount given to consumers to reduce consumption and the benefits of selling to the spot market the difference between contract and actual consumption. It is supposed that, due to the price volatility in Brazil this utility is 100% contracted with a generator and thus may use it to act as load reduction.

For an accurate analysis, it is required spot price and generation scenarios that accurately reflect the volatility and time dependence of the system being modeled. For carrying out this task, we have applied a probabilistic modeling to the main sources of uncertainty such as load fluctuations, equipment outages, hydrological conditions, etc. and spot prices were calculated from the solution of a hydrothermal generation dispatch model [1]. We have used the computational model SDDP that can provide the utility with generation and spot price scenarios. SDDP is a constrained probabilistic production-costing model. It determines the optimal stochastic operation policy of a multi-reservoir hydrothermal system without aggregating hydro reservoirs through Stochastic Dual Dynamic Programming [1].

We have considered the Brazilian Interconnected system (as of September 2000) with a rationing cost of US\$1000/MWh. This value is particularly important because, besides to indicate the "cost of unserved energy", it corresponds a cap on the spot price. We have carried out a probabilistic simulation of the Brazilian system (with SDDP model) for the years 2001-2004. In this simulation, 60 synthetic inflow scenarios were produced with a streamflow model [1].

6.1 Definition of the Load Retraction Strategy

LIGHT is a Brazilian Utility with a global market of 24059 GWh, a peak load of 4400 MW and a residential consumers's market of 8421 GWh (2000 data).We have concentrated our analysis of load reduction on the residential consumers of this utility, which represent 35% of the overall utility's market. A detailed poll recently realized among these consumers [3] observed that around 4% of the peak load (176 MW for Rio de Janeiro area) would be considered as a potential for load reduction. Therefore, for simplicity, we have assumed that all 4% of the residential load is the amount to be reduced on peak times by means of negotiation (discounts in electricity bill) by the utility with its residential clients.

Observe that the utility must offer its amount of energy to be reduced on the spot market with an associated price. In turn, this price must be around its tariff (residential tariff in this work). The reason in straightforward: if the price for load reduction is very lower than its tariff, the utility will be damaged whenever has to reduce its consumption, as it will sell its energy to the spot market by a spot price which can be lower than its tariff. In this case, it would have done better receiving the usual payment from its clients. Hence, we have considered in this work a price for load reduction higher than the residential tariff of LIGHT which is of US\$ 77.3/MWh. The objective for the utility is to reduce its consumption whenever the spot price on peak hours exceeds this value. In Brazil, taxes play a important role on tariffs. Thus, for sensitivity, the possibility of prices lower than the tariff due to reduction on taxes (a tax revision is being considered by the country) was also considered.

6.2 Load Retraction in LIGHT area

We have simulated the Brazilian Interconnected System with 4% of LIGHT residential's load acting as load reduction with an associated price in peak hours. We selected [3] US\$85.9/MWh as a base load reduction price to start our analysis. Table 1 presents the average annual spot prices and the mean annual load reduction of LIGHT associated to this price of reduction. It can be observed that in the year 2001 the plant is dispatched most. This is coherent with the current Brazilian rationing situation with results in high market prices in the short-term.

Year	2001	2002	2003	2004
Spot Price (US\$/MWh)	221.8	149.6	69.8	41.5
Reduction (GWh)	59.9	30.7	16.4	10.8

Table 1: Yearly Spot Price and Load Reduction

The gross revenue of the utility due to the spot sales from the amount reduced is presented in Table 2. The expected value of the spot sales over the 4 years is MUS$[1] 70.8.

Year	2001	2002	2003	2004
MUS$	34.0	22.1	9.6	5.1

Table 2: Yearly Gross Revenue

In order to obtain this load reduction it is recommended to the utility to establish a deal with its clients to curtail their consumption (on peak times) with a certain frequency. In this work we have analyzed discounts (from 6 to 10%) in the consumer's energy bill as an incentive from the utility.

A tariff with a discount associated to load interruptions represents a new product to be offered by the utilities to their clients that agree to reduce their consumption in the peak load or even to be curtailed according to a utility's criteria. Observe that this reduction may be total or partial, as it depends intrinsically on the spot price behavior, which in turn is stochastic. Clients desiring a high degree of reliability would accept to participate in such scheme only with a high discount, whereas there may be clients accepting smaller discounts in change of load reduction.

In Table 3 the annual losses to the utility due to the interruptions moments, for a discount of 10% on the tariffs, are shown.

Year	10%	9%	8%	7%	6%
2001	4.2	4.2	4.3	4.3	4.4
2002	2.1	2.2	2.2	2.2	2.2
2003	1.1	1.1	1.1	1.2	0.1
2004	0.8	0.8	0.8	0.8	0.8
Total	8.2	8.3	8.4	8.5	8.6

Table 3: Annual Losses due to Interruptions (US$ 10^6)

Considering a load factor of 50% [3] it was established that the annual load to be reduced would be of 771 GWh (176MW × 8,760 h × 0.5). Therefore, a fixed 10% discount in the residential tariff would represent a yearly loss of billing of 5.96 MUS$ (7.73 US$/MWh × 0.771 TWh).

Hence, the expected total net revenue (NR) of the utility (over the 4 years simulated) considering the losses due to billing (Table 3) and a 10% discount due to the load reduction would be of: NR (MUS$) = 70.8 – 8.2 – 4 × 5.96 = 38.8

The previous analysis was carried out to 4 different values of price associated to the load reduction: 107.4, 85.9, 64.4 and 55.8 US$/MWh. Table 4 presents the expected revenue of the utility (over 4 years) as a function of the discount given to its clients and according to the price submitted for load reduction.

[1] MUS$ = Millions of US Dollars (US$) in this work

Discount	**Price for Load Reduction (US$/MWh)**			
	55.8	**64.4**	**85.9**	**107.4**
10%	38.7	38.8	38.8	38.5
9%	41.0	41.0	41.0	40.8
8%	43.2	43.3	43.3	4.3
7%	45.5	45.6	45.6	45.4
6%	47.8	47.9	47.9	47.7

Table 4: Total Income – Discount x Price for Reduction (Millions of US$)

We can observe the increase of the revenue as the discount decreases. Even though the net revenue presents smooth variations with the price submitted for the load reduction, the higher benefits were observed when this price ranges between US$64.4/MWh and US$85.9MWh. Just for comparison purposes, the yearly net revenue (spot revenue of the reduced load minus loss of billing due to the interruption times) is almost 3 times higher than the value of the incentive (discount of 10%). This can be observed on Table 5 for all cases considered.

Price (US$/MWh)	Net Revenue[(1)] (US$ 10^6)	Incentive (US$ 10^6)
107.4	62.3	23.8
85.9	62.6	23.8
64.4	62.6	23.8
55.8	62.5	23.8
[(1)] (Spot Revenue – losses from load interruption on peak hours)		

Table 5: Revenues x Incentive for load reduction

In fact, the difference of the Net Revenue and Incentive presented in Table 5 gives the results of Table 4.

6.3 Risk Analysis of Load Retraction

Figure 5 presents the probability distribution of the incomes from the load retraction obtained by LIGHT considering the case described in section 6.1 (reduction price of US$85.9/MWh, residential tariff of 77.3US$$/MWh and incentive of 10%). Even though the expected value of the net income is 62.6 MUS$ (with higher upsides in some scenarios) we can observe that, over the 4 years analyzed, the income obtained is lower than the loss due to discounts (23.8 MUS$) in 68% of the scenarios simulated.

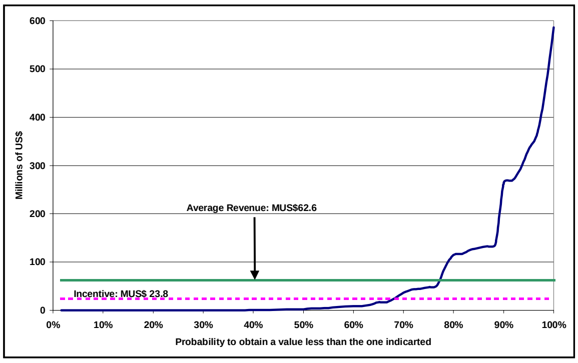

Figure 5: Probability Distribution of Incomes

This occur because the incomes are associated to the spot price which, as depicted in Section 2, has a skewed probability distribution in the Brazilian system. This is a very uncertain cash flow and the decision making in this case is not trivial to individual with a risk-averse profile (as most of utilities). Therefore, in the next sections the load management analyzed in this section will be analyzed again now by means of utility functions, as explained in section 5, attempting to capture the risk-averse profile of the utilities.

6.4 Evaluation Through Utility Functions

In order to manage the risk previously described, we decided to apply a utility function on the incomes earned by the utility to analyze the effect of its volatility on overall performance. We have established a risk-averse utility function with a breakpoint at the value corresponding to 80% of the losses due to the incentive to clients. The idea is, thorough a concave utility function, to penalize the incomes that do not remunerate at least 80% of the "investment" (losses) made with discounts rather than compensate "good" results. The utility function used to evaluate the revenues, when the reduction price of US$ 85.9/MWh, is presented in Figure 6, where the expected utility of the incomes is 94.3 utility units with a certainty equivalent of 18.8 MUS$.

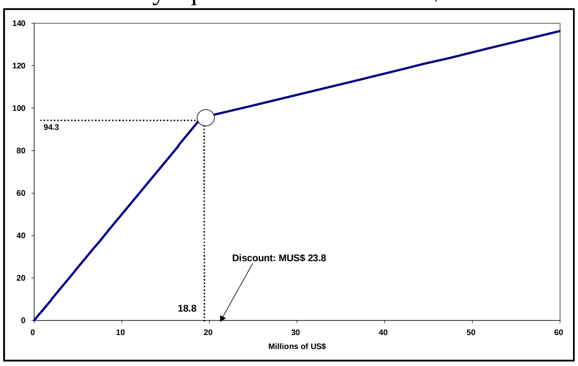

Figure 6: Utility Function – Incentive of 10%

Given the skewness and volatility of the revenues, the certainty equivalent is 21% lower than the investment in incentives (discounts), which thus turns out the concept to be undesirable (in this case).

Figure 7 presents the utility curve to the incentive of 6% and we can observe the attractiveness of this alternative. For an incentive of 14.3 MUS$, the certainty equivalent of the revenues over the 60 scenarios simulated is 37.2 MUS$.

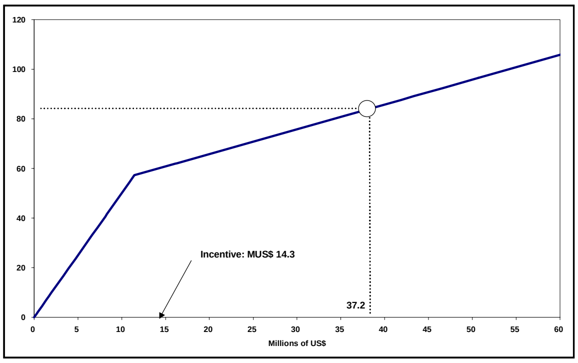

Figure 7: Utility Function – Incentive of 6%

Hence, we have fixed the price-bid for load reduction in US$85.9/MWh and extended the previous analysis to different levels of discount to consumers. For each discount level we calculated the certainty equivalent of incomes (according to the previously defined utility function) and compared it to the loss due to the discounts. The results (in MUS$) are shown in Figure 8. It can be observed that discounts lower or equal to 9% are attractive to the utility, as they present a certainty equivalent higher than the incentive. However, lower incentives may not be of interest to consumers.

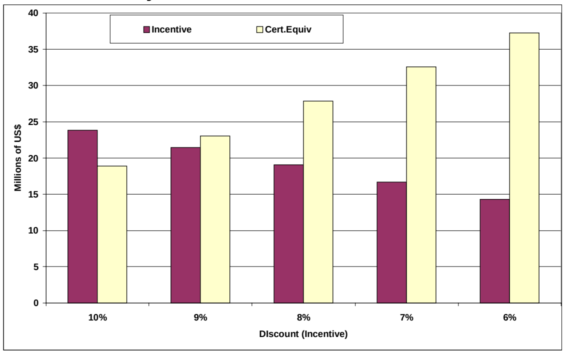

Figure 8: Incentive and Certainty Equivalent - 85.9US$/MWh

Figure 9 shows that the aforementioned results are maintained if the price-bid for load reduction is 64.4 US$/MWh: in terms of a risk averse utility function, the negotiation with clients is profitable for a discount of 9% and disadvantageous for a discount of 10%.

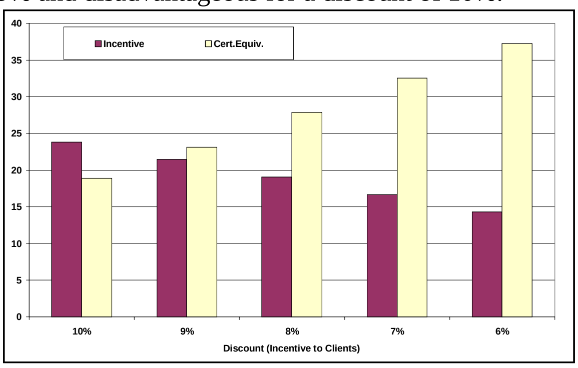

Figure 9: Incentive and Certainty Equivalent (64.4 US$/MWh)

Finally, we have analyzed the impact of a rate increase if the price for load reduction is kept constant. It was observed that a notable increase on the residential tariff might reduce the attractiveness of the business in function of the discount (incentive) to clients. For price for load reduction of US$85.9/MWh, Figure 10 shows that if the residential tariff raises around 10% (from 77.3 US$/MWh to 85.9 US$/MWh), the maximum profitable discount falls from 9% to 8% (point where the certainty equivalent starts to grow again).

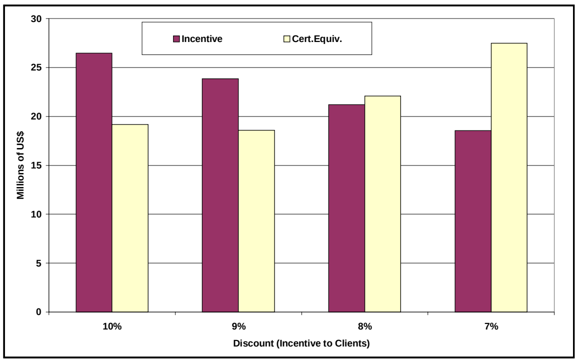

Figure 10: Certainty Equivalent – Price bid and Tariff equal to 85.9 US$/MWh

A similar analysis was carried out considering a tariff increase to 107.4 US$/MWh with a price bid of US$85.9/MWh, the maximum profitable discount falls even more to 6%. For this last case, the best solution would probably be to set the price bid for load reduction in the range of this tariff value as well.

7 CONCLUSIONS

The low price-demand elasticity of the electric power has lowered actions of demand flexibility, reason throughout several programs of energy conservation implanted in the last years didn't have the expected success. Customers of all segments are always sensitive to energy interruptions [4], some due to the financial damage (industrial and commercial), others due to the dissatisfaction that those events provide. In practice what exists is a disposition to pay for the use of the electric power, that doesn't simply decrease with the increase of the tariffs.

The analysis carried out in this work tried to capture the benefits for a distribution company of a load reduction and selling of the amount reduced in the spot market when spot prices are high in a hydro-based system. The analysis were based on the comparison between the expected value of an uncertain cash flow (associated with the spot prices scenarios) and a fixed loss related to incentives given to consumers to guarantee the load reduction in the peak hours plus losses from billing at the interrupting times. It was shown that even though the benefits may be high (in terms of expected value), its volatility may make it not so attractive when the analysis is carried out by means of a risk-averse profile using utility functions. A policy of incentives to the residential consumers can be feasible, once it does not bring financial damages to the Distribution Company. In the analyzed cases it was observed that the utility would have profits only for discounts lower to 10%. On the other hand, very low discounts may not be attractive for the consumers. A more detailed analysis should be carried and this should be specifically for each market being analyzed.

Finally, in case generators and loads are 100% contracted there is a financial risk for the generators in a load reduction action: as bilateral contracts are financial hedges, if load is reduced, all generators will be short and all loads will be long on their contracts by the amount reduced. This entails a very large monetary transfer from generators to loads. The distribution companies are supposed to receive a substantial amount of money from generators because they are now long on their contracts. This implies in a risk to the generators that ought to look for hedging strategies through the financial instruments available on the market [5].

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