ASSESSMENT OF ELECTRICITY DISTRIBUTION COMPANIES RISKS IN THE BRAZILIAN ENERGY MARKET FRAMEWORK

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ABSTRACT

The aim of this paper is to assess the financial risks that the Distribution System Operators (DSOs) incur in the energy commercialization process in Brazil. We present a brief description of the Brazilian Energy Sector (BES), the decision process and the risks involving purchasing decisions in order to understand the Brazilian framework from a DSO point of view. In this paper we propose a methodology to calculate and evaluate the financial impact that the decisions may have in the budget of the DSO. This methodology includes the stochastic simulation of the decision on several scenarios of demand and energy prices. We apply it to two case studies that allow a better comprehension of the risks involved and their impact in terms of profits or losses. The results indicate that the risks can be as high as hundreds of millions of Brazilian Reais.

INTRODUCTION

The Brazilian Energy Market has been through a deregulation process in which transmission and distribution are considered natural monopolies whereas generation and energy commercialization are part of a competitive market. One of the main consequences of this model is the fact that Distribution System Operators (DSOs) must handle the risks of all regular consumers (residential, commercial and some industrial) regarding the energy requirements. However, as they can only charge a tariff approved by the Brazilian regulatory agency, they incur in risks of buying an excessive amount of energy or paying penalties in case of insufficient energy to meet the consumption of its customers.

In this context, this paper aims at describing the Brazilian Energy Market framework and the financial impact that purchasing decisions may have in the budget of a distribution company. Although in this paper a mathematical modelling considering the energy trade decisions is not addressed, a forehand financial analysis is extremely important to understand the issues that should be taken into account in the decision process.

It is important to mention that even though the energy trade should not be the main focus of the DSO, the decisions related to energy may have a significant impact in the final revenue, especially due to the Brazilian regulatory framework, which has a lot of trick rules concerning the distribution company obligations.

In order to evaluate the financial impact of the decisions in the DSO's revenue, we analyse two cases with several scenarios for demand and spot prices over a 30-year horizon in which the decisions were taken based on the expected load. We show that the financial setback depends on the scenarios, so we make use of the Expectation, Value-at-Risk and Conditional Value-at-Risk [1] to assess the results.

This paper is organized as follows; we start by discussing the Brazilian Energy Sector very briefly. In the sequence, we describe the decision and risks involved in the energy commercialization problem of a DSO and we show the methodology used to make the financial assessment. Afterwards we present our case studies and, finally, we make our final remarks.

BRAZILIAN ENERGY SECTOR

Since 1995, the BES has experienced deregulation and restructuring [2]. A primary objective of the new market structure was to stimulate the private sector to invest in the electricity market. In this new regulatory framework, the energy companies were separated into different companies in the segments of generation, transmission and distribution. The market was designed to have competition in generation and commercialization, whereas the transmission and distribution segments maintained their natural monopoly.

The BES has two commercialization environments [3]: the Regulated Market Environment (RME) and the Free Market Environment (FME). The RME includes all residential and some commercial/industrial consumers, where they pay a tariff to the distribution company that is regulated by ANEEL (Brazilian National System Regulator). The FME includes all eligible consumers (demand greater than 3.0 MW) that opt to directly negotiate their energy supply with generation companies and commercialization companies via bilateral contracts.

The DSOs are the main part of the RME, as they are responsible for buying the energy to meet all regular consumers (residential, commercial and some industrial). The DSOs are supplied by the following form:

i. They can buy energy through auctions [4] organized by ANEEL;
ii. They can make a call for distributed generation under their concession area, but limited to a maximum of 10% of DSOs load;
iii. Fixed supply from specific plants that are shared over all DSOs proportionally to their market share, these sources include but are not limited to: binational Itaipu plant, plants from the Incentive Program for Alternative Sources of Electric Energy (PROINFA), Angra I and Angra II nuclear plants.

As aforementioned, item ii is limited to 10% of DSOs load and item iii can be around 30% of DSOs load in 2014. As a result, most energy supply to the consumers must be bought through auctions. The auctions were created during the deregulation process in Brazil as a strategy to provide long term contracts to new power plants and attract new investments to the BES.

Therefore, there are four types of auctions which are nominated as A-5, A-3, A-1 and adjustments. The A-*y* auctions indicate that the energy will be delivered *y* years after the auction. Hence, the 5 and 3 years auctions are designed for new power plant that will take up to 5 or 3 years to be constructed, respectively, while the A-1 and adjustments auctions are designed to buy energy from existing power plants.

The Brazilian electricity market was designed in such a way that all consumption must be backed up by contracts and all contracts must be backed up by real generation, which if there is an imbalance in one of these cases, some penalties are applied to the agent that have not met their requirements. In addition to that, the Short-Term Market (STM) is a market for differences, where the difference between the contracts and the consumption, in the distributions company case, is valued by the spot price which is computed by means of hydrothermal generation scheduling models [5].

ENERGY DECISIONS AND ITS RISKS

In this section we describe the decisions that must be taken by the DSOs and some of its risks, considering the framework presented in the previous section.

Contracts arising from auctions have specific regulations regarding energy prices, registration submarket of the contract and duration of supply, which are not subject to bilateral negotiations by the agents. The distribution agent only indicates its energy needs in future years and may not choose source, price or supplier. As a result, we have that at any given year the DSO has to make the following decisions:

a. The amount of energy in auctions A-5;
b. The amount of energy in auctions A-3;
c. The amount of energy in auctions A-1;
d. The amount of energy in auctions of adjustments;
e. Energy reallocation among other DSOs;
f. Call for distributed generation within its concession area.

In the fifth item, the energy reallocation can be done through the so called MCSDs (Portuguese initials for “Deficits or Surplus Compensation Mechanisms”). The purpose of the creation of the MCSD was to adjust the differences in the Energy Trading Agreements in the Regulated Environment – CCEARs. These compensation mechanisms are contractual transfers of CCEARs from a distributor that has sparing energy to another distributor that has deficit. However, in these cases the possibility of power purchase is not ensured, being restricted to the offer made by the generators and/or traders.

The limits for each of these decisions are defined below in the same sequence as the previous list:

a. No limits;
b. Limited to a maximum 2% of total verified load two years before the auction;
c. Limited to a minimum of 96% the amount of energy from previous contracts that will expire in that year;
d. Limited to a maximum of 1% of the total contracted load.
e. No limit, but depends on availability of other DSOs.
f. The total contracts cannot sum more than 10% of the total consumption in that year.

It is important to mention that, although the DSO may in some cases buy energy out of those limits, they are not allowed to charge their customers through the tariff for the energy bought outside the limits. Therefore, they need to plan their decisions to meet those limits.

The distribution company would be willing to not meet the limits above if its total energy bought through contracts and from specific plants (as described in the previous section) is greater than 105% or lower than 100% of the total load in that year, as in those case the DSOs are charged with high cost penalties. If the energy portfolio is within all limits described so far, all cost will be refunded through the tariff from its consumers.

As the DSO do not know the total consumption throughout the year when making decisions, it becomes clear that there are risks involved in making those decisions. So, we are facing two main risks:

- Buying energy outside the limits defined in *a-f*, which will be charged by the difference between the contract price and some reference value.
- Buying more energy than 105% or less energy than 100% of total load. When the distribution company buy energy in excess, the additional energy needs to be sold in the STM at the spot price. When there is an energy deficit, the DSO needs to buy energy from the STM and it pays a penalty.

An example of situation that can occur and that the power purchase planning has no conditions to foresee is an extreme heat situation, as in the first quarter of 2014. In this period, heat waves hit successively the region of Santa Catarina state (Southern of Brazil). In January of 2014 we had the hottest month in the afternoon in the last 88 years in the region of Florianópolis. In February of 2014 we had 18 days of intense heat, the hottest period for this month since the year of 1911, meaning that in 103 years there was no record of a similar event.

As the load plan for the year of 2014 had been made five years ago and revised with three years of antecedence (auctions A-5 and A-3), there would be no possibility of purchasing the required energy for the extreme situation that occurred in that period. In Table 1 we can compare the historical average growth of the TRC (total required consumption) with the growth occurred in the first three months of 2014. From a historical level of around 3%,

there was a growth to 16% in the first two months and from 2.5% to almost 10% in March. This shows that an real situation can seriously increase the risks for the DSO.

Table 1 - Total Required Consumption analysis.

	Jan/14	Feb/14	Mar/14
TRC 2014 (MWm)	2573.33	2743.64	2404.68
Contract (MWm)	2217.52	2313.99	2273.94
Exposure (MWm)	-355.81	-429.66	-130.75
TRC 2014/2013 (%)	17.16	16.38	9.87
Average Growth TRC 2009-2013 (%)	3.08	3.53	2.41

Tools to adjust this imbalance are the adjustment mechanisms described above. But as we have already mentioned, there is no energy supply security in these mechanisms, since they are based on existing energy and dependent on the supply of this source of energy.

Given the facts, it is possible to notice the difficulty of planning the power supply for a distributor in the Brazilian electricity sector and also the inherent fragility of the adjustment mechanisms available.

METHODOLOGY

In this paper we intend to assess the financial risks of a distribution company in the Brazilian Energy Market. So in this section we present the methodology proposed to evaluate the consequences of the decision process. It is important to point out that we do not intend to propose a complete methodology to support decisions, but assess their potential financial risks.

In order to compute the total revenue for a given set of decisions, we will assume that all energy that can be charged through the tariff has a fixed impact in the revenue of the DSO. As a consequence, we compute the revenue based only on the difference of the risks described in the previous section, which can be negative or positive depending on the spot price, contracts prices and which limits were not satisfied.

Therefore, assuming the L_t is the total load for a given year t, we have that the revenue for a given year t can be calculate as follows :

$$\begin{aligned} R_t = &-\left[\sum_{\tau=t-14}^{t} \left(PC3_\tau - \min(PC3_\tau, PC5_{\tau-2})\right) \max\left(0, (C3_\tau - 0.02L_{\tau-2})\right)\right] \\ &- \sum_{\tau=t-2}^{t} (MPC_\tau - RVE_\tau) \max\left(0, (0.96CE_\tau - C1_\tau)\right) \\ &- (APC_t - SP_t) \max\left(0, (TC_t - 1.05L_t)\right) \\ &- \left[(SP_t - \min(SP_t, RV_t)) + \max(SP_t, RV_t)\right] \max\left(0, (1L_t - TC_t)\right) \\ &- \left(PCA_t - \min(SP_t, RV_t)\right) \max\left(0, (CA_t - 0{,}01L_t)\right) \end{aligned}$$

Where,

R_t Revenue in year t ($);
$PC3_t$ Price for contracts in auction A-3 in year t ($/MWh);
$PC5_t$ Price for contracts in auction A-5 in year t ($/MWh);
$C3_t$ Contracts in auction A-3 in year t (MWh);
RVE_t Reference Value for Existing Energy in year t ($/MWh);
$MPCt$ Maximum Price of Contracts A-5 and A-3 in year t ($/MWh);
CE_t Contracts expiring in year t (MWh);
$C1_t$ Contracts in auction A-1 in year t (MWh);
APC Average Price Contract considering only contracts to sum the energy excess in year t ($/MWh);
SP_t Average Spot Price;
TC_t Total contracts active in year t (MWh);
RV_t Reference Value in year t ($/MWh);
PCA_t Price for contracts in the Adjusment Auction in year t ($/MWh);
CA_t Contracts in the Adjusment Auction in year t (MWh).

The financial assessment is made by assuming a period of 30 years, in which will assume a known load growth (G_t) in year t for which will take the best decision. We will then simulate the decisions considering a stochastic demand growth which will be modelled by a very simple uniform distribution over the deterministic growth varying 1%. As a result, we have a uniform distribution [G_t-1%, G_t+1%].

Given that there many more uncertainties in the long run, such as political ones, we assume that the load grows for the first five years and remains stable for the next 25 years.

The average spot prices will be computed using the official long term hydrothermal scheduling model [5]. The model provides 2000 scenarios of prices for the next five years. As the spot price uncertainty can be assumed to be independent to the demand growth, we will make use of Monte Carlo sampling strategies to meet both random variables for the first five years. In the next 25 years, we consider the same strategy, but we only use spot prices from the last year.

Finally, it is possible to compute the total revenue for each scenario s as the net present value of the revenues throughout the 30-year horizon, which is shown in the equation below:

$$RT^s = \sum_{t=1}^{30} \frac{1}{(1+\beta)^{t-1}} R_t^s$$

Where,

RT^s Total revenue in scenario s ($);
β Discount factor.

Given that we have N scenarios, we could use 2000 scenarios for instance, it is possible to compute the expected net revenue and its Conditional Value-at-Risk [1], allowing us to understand the risks involved in the trading.

CASE STUDY

In order to evaluate the consequences of the decision process, the idea of this study is to use some simulation to assess the financial risks. As aforementioned, we consider a case with 2000 scenarios of spot prices and demand to simulate decisions that are made taking into account the average value of both random variables. We will consider the energy prices obtained through the long term hydrothermal scheduling model using information from 2011 and 2014.

In the examples analysed in this paper, we assume the following conditions for all stages $t = 1,\ldots, T$:

- RV_t = 80.69 R$/MWh;
- $PC3_t$ = 196.11 R$/MWh;
- RVE_t = 149.00 R$/MWh;
- MPC_t = 215.12 R$/MWh;
- APC_t = 196.11 R$/MWh.

We assume that Adjustment Contracts are only signed within its limits and the initial conditions are as follows:

- Load = 5,461,674.00MWh;
- Growth of the Load in the first five years is 4% and 0% from the sixth year onward with an oscillation of ± 1%;
- Initial set of contracts meet 101% of the Load;
- Existing contracts end in the next 20 years at a fixed 5% a year.

It is important to mention that all contracts decisions were made considering that we cannot face any financial setback if we have the average load over the 2000 scenarios.

Case 01

In our first case, we consider that in the previous years and in the first five years the decisions taken provide the following profile of new contracts:

Table 2 – Contracts in (10^3 MWh)

	Year					
	1	2	3	4	5	6
A-5	120	350	0	350	40	120
A-3	109.2	54.6	54.6	56.8	59.0	0

In addition to those contracts, we assume that we will re-sign 98% of the contracts that are expiring that year and there is an addition A-5 contract of 200,000 MWh to start in year 10.

Case 02

In our second case, we consider that in the previous years and in the first five years the decisions taken provide the following profile of new contracts:

Table 3 – Contracts in (10^3 MWh)

	Year					
	1	2	3	4	5	6
A-5	50	100	130	200	40	120
A-3	109.2	109.2	109.2	113.6	118.1	0

Furthermore, we assume that we will re-sign 99% of the contracts that are expiring that year and there is an addition A-5 contract of 50,000 MWh to start in year 10.

Comparison of Cases 01 and 02

We compare the two decision profiles by calculating the financial impact that those decisions may have in the fixed revenue, which is shown in Figure 1. As one can notice from the figure, even though both profiles meet the requirement of no financial losses for the average load, they may have a very different financial impact.

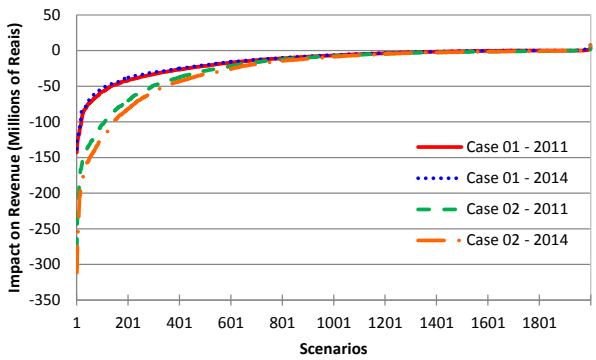

Figure 1 - Impact in the Revenue (Millions of Brazilian Reais)

The values shown in Figure 1 are computed as the net present value over the 30-year horizon using a 10% discount factor. As we are considering 2000 scenarios with the same probability, we have that the Value-at-Risk and Conditional Value-at-Risk for a 5% of the scenarios and the expected impact as show in Table 4.

Table 4 - VaR, CVaR and Expected impact in Millions of Brazilian Reais.

	VaR	CVaR	Expected
Case 01-2011	-57.671	-80.353	-15.021
Case 01-2014	-52.554	-74.892	-13.949
Case 02-2011	-104.055	-141.211	-23.179
Case 02-2014	-121.910	-163.945	-26.920

From the table above, it is possible to observe that Case 01 is a much better decision than Case 02, even though

both cases were computed avoiding the financial risks for the average load. These results indicate that it is important to build a stochastic programming model [6] that takes into account the random variables and benefits/risks of each auction in the long run.

Although the previous results provide an interesting point of view, it is important to understand the impact related to the energy commercialization fixed revenue of the DSO (we are not considering other forms of revenues for distributing energy). In order to do that, we will assume that the fixed revenue is the total of contracts every year multiplied by the average pricing of contracts, which in this paper was assumed to be 130 R$/MWh.

In Figure 2, the average impact that the decisions may have on the fixed revenue is shown. These results indicate that, on average, the DSOs would be facing much higher risks at the end of the horizon.

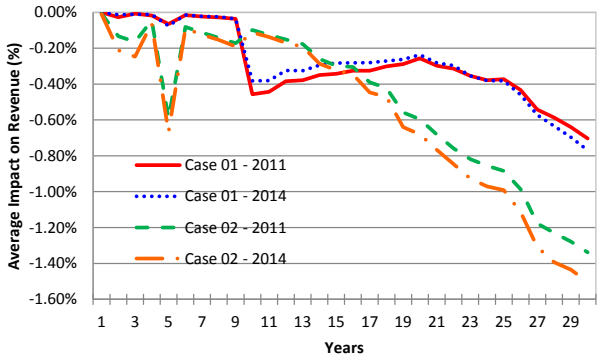

Figure 2 - Average Impact on Revenue.

When observing the maximum impact in any given scenario (Figure 3), we notice that the DSO may be facing a much higher risk even in the first five years of the horizon.

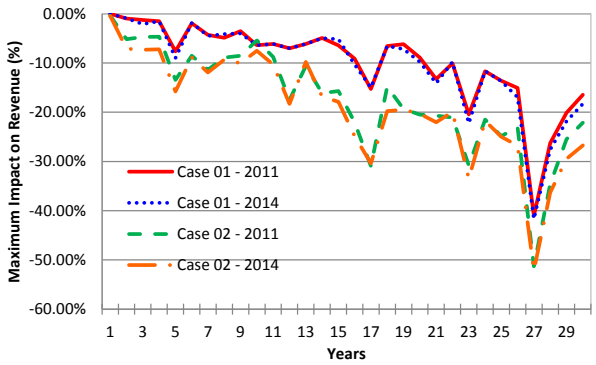

Figure 3 - Maximum Impact on Revenue.

Even though one might think that the risks may not be substantial on average, it is important to remember that the DSO is not allowed to profit from the energy commercialization process. As a result, their tariffs are regulated aiming at reimburse them for the payment of the long run contracts. Therefore, all values computed in this section are not taken into account in the tariff and, as a result, they are financial setback (losses) to the DSO.

CONCLUSIONS

In this paper we discussed the main aspects that the DSOs must face in the Brazilian Energy Market, in which they are responsible for managing the contracts need to provide energy to all regular consumers in their region.

We have shown that these financial risks may be quite substantial with average losses around 15-20 million Brazilian Reais (BRL) in our examples and they can get as high as hundreds of millions of BRL. One can observe that these values depend directly on the decisions taken, which indicates that it makes sense to invest in a decision model that takes into account all variables and requirements.

In short, the results indicate that although distribution companies in Brazil do not profit from the trading energy, the risks involved in the decision process may affect significantly the budget of the company.

Finally, it is important to mention that we consider the most important aspects of the Brazilian framework, some simplifications were made in order to be able to make the calculations.

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