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

Vitor L. DE MATOS
Plan4 Engenharia - Brazil
vitor@plan4.com.br

Rodrigo L. ANTUNES
CELESC - Brazil
rlantunes@celesc.com.br

Marcos T. COELHO
CELESC - Brazil
marcostc@celesc.com.br

Guilherme MATIUSSI
Plan4 Engenharia - Brazil
gmatiussi@plan4.com.br

Rodolfo C. Machado
Plan4 Engenharia - Brazil
rcmachado@plan4.com.br

## *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 focus of the DSO, the decisions related to energy may have a significant impact in their final revenue, especially due to the Brazilian regulatory framework, which involves manifold rules concerning the distribution company obligations.

In order to evaluate the financial impact of the decisions in the DSO's revenue, we analyse four 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 validity of 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 negotiate directly 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 compulsory supply from specific plants that are shared over the DSOs proportionally to their loads, 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 and hydro energy quotes.

As aforementioned, item ii is limited to 10% of DSOs load and item iii is increasing its importance due to the fact that most contracts renewals are becoming hydro energy quotes agreements. As a result, there is an amount of energy supply that is bought through auctions, mainly the ones related to new power plants to be constructed and the renewal of contracts of thermoelectric plants. 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, despite the fact that the regulation allows several auction products, in recent years, only four products have been made available to DSOs: 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 plants that will take up to 5 or 3 years to be built, 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 amount contracted and the consumed, 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 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 MCSD goal is 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. In all other cases the amount of energy purchased depends on the offers made by generators and/or traders, consequently it might not be enough to meet the DSO’s energy requirements. In this situation, the regulator allows this energy to be bought in the STM.

The main limits for each of these decisions are summarized 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 5% of the total contracted load;
e. No limit depending on the mechanism, 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 in some cases may 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.

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

- Buying energy outside the limits defined in *a*- 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.

## RECENT REGULATION CHANGES

In the previous section we described the main regulations aspects, however along 2016 several changes in the regulations were sanctioned and we will discuss briefly the most relevant ones in the context of this paper. Nowadays, most DSO’s in Brazil have a surplus of energy, so the main changes were regarding strategies to reduce this excess of energy and make it available to the market.

The first aspect worth mentioning is the additional flexibility to the 96% compulsory purchase of expiring

contracting. If the DSO has a surplus there is no minimum limits for re-contracting from expiring contracts.

Furthermore, if the DSO has still an excess of energy, they will be allowed to sell that energy to the FME. And, finally, the compensation mechanism (MSCD) that used to be only for energy bought from existing power plants, can also be used in the case of energy from new power plants (contracts from A-5 and A-3 auctions).

## 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. Therefore, we compute the revenue based only on the difference of the risks described in the previous sections, which can be negative or positive depending on the spot price, contracts prices and which limits were not satisfied.

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

$$\begin{aligned} R_t = -\Bigg[ \sum_{\tau=t-14}^{t} \big(PC3_\tau \\ - \min(PC3_\tau, PC5_{\tau-2})\big) \max\big(0, (C3_\tau - 0.02L_{\tau-2})\big)\Bigg] \\ - \sum_{\tau=t-2}^{t} (MPC_\tau - RVE_\tau) \max\big(0, (0.96CE_\tau - C1_\tau)\big) \\ - (APC_t - SP_t) \max\big(0, (TC_t - 1.05L_t)\big) \\ - \big[\big(SP_t - \min(SP_t, RV_t)\big) \\ + \max(SP_t, RV_t)\big] \max\big(0, (1L_t - TC_t)\big) \\ - \big(PCA_t - \max(SP_t, RV_t)\big) \max\big(0, (CA_t - 0.05L_t)\big) \\ + (PS_t - SP_t)SA_t \end{aligned}$$

Where,

$R_t$ Revenue in Risk 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).
$SA_t$ Sold Amount in year $t$ (MWh).
$PS_t$ Selling Price 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 contracting strategy.

## 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, except in two case. We will consider the energy prices obtained through the long-term hydrothermal scheduling model simulation.

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

**Table 1 – Conditions**

| | $RV_t$ | $PC3_t$ | $RVE_t$ | $MPC_t$ | $APC_t$ |
|---|---|---|---|---|---|
| R$/MWh | 80.69 | 196.11 | 149.00 | 215.12 | 196.11 |

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

- Load = 5,461,674.00MWh;
- The initial contracting position is 101% of the Load;
- Growth of the Load in the first five years is 4% and 0% from the sixth year onward with an oscillation of ± 1%;
- Existing contracts end in the next 20 years at a fixed amount reduction of 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, except in Cases 3 and 4.

The study is composed by four contracting strategies. The first two correspond to two different auction contracting strategies, the third corresponds to contract an amount of 10% more by auctions A-5 in relation to the first strategy without selling energy and the fourth strategy corresponds to the third one but selling energy to the FME.

The contracting amount in each auction is given by the following table, the number in parenthesis besides the auction indication corresponds to the strategy itself.

**Table 2 – Contracting Strategy in ($10^3$ MWh)**

| | Year | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 |
| A-5 (1) | 120 | 350 | 0 | 350 | 40 | 120 |
| A-3 (1) | 109.2 | 54.6 | 54.6 | 56.8 | 59.0 | 0 |
| A-5 (2) | 50 | 100 | 130 | 200 | 40 | 120 |
| A-3 (2) | 109.2 | 109.2 | 109.2 | 113.6 | 118.1 | 0 |
| A-5 (3-4) | 132 | 385 | 0 | 385 | 44 | 132 |
| A-3 (3-4) | 109.2 | 54.6 | 54.6 | 56.8 | 59.0 | 0 |

In addition to those contracts, to the case 1, 3 and 4 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. In case 2 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

We compare the decision profiles by calculating the financial impact that those decisions may have in the fixed revenue, which is shown in **Erro! Fonte de referência não encontrada.**. As one can notice from the figure, it is possible to verify that the impact is related to the contracting strategy, as can be verified in cases 1 and 2. In Case 3 there is an energy surplus that is sold monthly by the spot price and it is affected by its volatility. This situation is mitigated in Case 4, given that the DSO sells 100,000 MWh every year at 199 R$/MWh, reducing the risk caused by the spot price volatility.

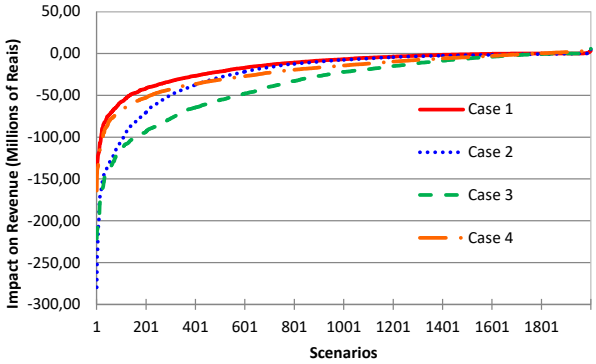


**Figure 1 - Impact in the Revenue (Millions of Brazilian Reais)**

The values shown in **Erro! Fonte de referência não encontrada.** 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 5% of the scenarios and the expected impact are shown in Table 3.

**Table 3 - VaR, CVaR and Expected impact in Millions of Brazilian Reais.**

| | VaR | CVaR | Expected |
|---|---|---|---|
| Case 1 | -57.021 | -80.353 | -15.021 |
| Case 2 | -104.055 | -141.211 | -23.179 |
| Case 3 | -114.990 | -145.847 | -36.333 |
| Case 4 | -67.145 | -89.382 | -21.248 |

From the table above, it is possible to observe that the contracting strategy followed by Case 1 offers less risk than Case 2. 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. Analyzing cases 3 and 4, one can notice by allowing the DSO to sell their energy surplus may mitigate their financial impact. Naturally, the selling strategy depends on the market price and the volume sold, as illustrated in Figure 2.

It is interesting to verify that the possibility of selling energy to the FME may change the DSOs approach in terms of portfolio management, as it needs to follow the energy market price and the FME demand given their potential importance to their expected revenue. Considering that, there is an extra flexibility in case the

DSO buys energy in excess; such decision models should take into account this new regulation.

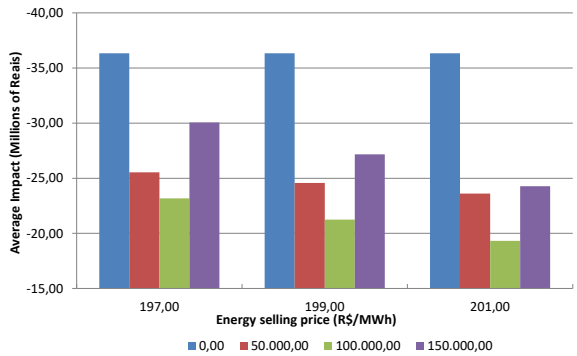


**Figure 2 - Average impact depending on the selling amount (MWh/year) and price (R$/MWh)**

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 over the years. 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 196.11 R$/MWh.

In Figure 3, 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, and there are some years which the agent can suffer spikes of losses. It is also interesting to verify at Case 3, that the exposure caused by over contracting can penalize strongly the cash flow of the company when it is not offered the possibility to sell energy in order to reduce the surplus.

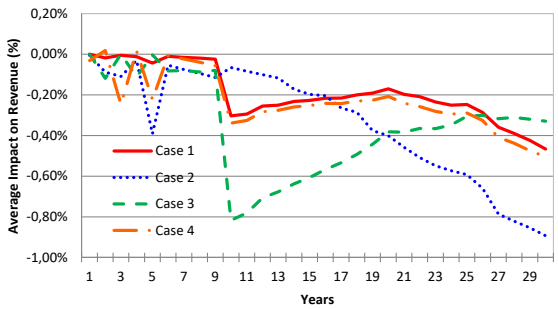


**Figure 3 - Average Impact on Revenue.**

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, no values computed in this section are 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 – R$) in our examples and they can get as high as hundreds of millions of BRL. It could also be observed that the recent changes on regulation, as the possibility of sell of energy in case of surplus, can modify the cash flow of DSOs, revising substantially the financial exposure depending on the market price and demand for energy. 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 energy trading, the risks involved in the decision process may affect significantly the budget of the company. Finally, it is important to mention that in this paper we consider the most important aspects of the Brazilian framework, some simplifications were made in order to be able to make the calculations.

## ACKNOWLEDGMENTS

This work was financed by Celesc through a P&D ANEEL project.

## REFERENCES

[1] R. T. Rockafellar and S. Uryasev, 2002, “Conditional value-at-risk for general loss distributions,” *J. Bank. & Financ.*, vol. 26, no. 7, pp. 1443–1471.

[2] L. Pinguelli Rosa, N. Fidelis da Silva, M. Giannini Pereira, and L. Dias Losekann, 2013, *Evolution of Global Electricity Markets*. Elsevier, pp. 435–459.

[3] E. Melo, E. M. de Almeida Neves, and L. H. A. Pazzini, 2011, “The Brazilian electricity model: An overview of the current structure and market design,” in *Energy Market (EEM), 2011 8th International Conference on the European*, pp. 592–597.

[4] E. E. Rego and V. Parente, Apr. 2013, “Brazilian experience in electricity auctions: Comparing outcomes from new and old energy auctions as well as the application of the hybrid Anglo-Dutch design,” *Energy Policy*, vol. 55, pp. 511–520.

[5] M. E. P. Maceira, L. A. Terry, F. S. Costa, J. M. Damázio, and A. C. G. Melo, 2002, “Chain of Optimization Models for Setting the Energy Dispatch and Spot Price in the Brazilian System,” in *14th Power Systems Computation Conference (PSCC)*, no. June.

[6] J. R. Birge and F. Louveaux, 1997, *Introduction to stochastic programming*. New York, N.Y.: Springer, p. xix, 421 p.