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EUI Working Paper **RSCAS** 2019/12

ISSN 1028-3625

Printed in Italy, February 2019
European University Institute
Badia Fiesolana
I – 50014 San Domenico di Fiesole (FI)
Italy
www.eui.eu/RSCAS/Publications/
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For further information
Florence School of Regulation
Robert Schuman Centre for Advanced Studies
European University Institute
Casale, Via Boccaccio, 121
I-50133 Florence, Italy
Tel: +39 055 4685 878
E-mail: FSR.Secretariat@eui.eu
Web: http://fsr.eui.eu/

Abstract

The performance of two ongoing regulatory frameworks for hydropower remuneration in Brazil is analysed. The former is the status quo design, where the individual operational risks are mitigated by a risk-sharing principle within a hydro pool structure. The latter is an insurance approach, where a security framework enables the hydro generators to transfer their risks to the consumers. Three different long-term scenario settings are assessed by using stochastic optimisation techniques. The results suggest that the level of risk in the status quo design strongly relies on the generation mix evolution, notably thermal, rather than wind or solar generation. The current insurance approach is likely to drive a transfer of wealth from consumers to generators. This condition can be overcome by adapting the insurance premium setting criteria.

Keywords

Hydropower; Risk Assessment; Call Options Obligations; Energy Allocation Mechanism; SDDP modelling.

1. Introduction[*]

Hydropower is the largest source of renewable electricity in the world with more than 1.2 TW of installed capacity, accounting for nearly 16% of the world's total electricity production (IEA, 2018). In Brazil, hydropower accounts for the majority of the 148GW of installed capacity. Therefore, this technology is crucial for meeting Brazil's current estimated annual consumption of 566 TWh/year, which is estimated to grow at 3.5% annually (EPE, 2017a). Due to the significant growth in non-hydro renewable energy source (RES) penetration, the market share of hydropower is projected to decline, reaching about 50% by 2026 (EPE, 2017a). Nevertheless, this source will continue to provide a significant part of Brazil's electricity generation in the long-run (EPE, 2017b).

According to IEA, (2012), since the early 1990s, one of the critical challenges for the development of hydropower projects is their financing. Hydropower development is capital intensive while the return on investment is climate dependent and may vary considerably from year to year, depending on the rain pattern. Thus, the power purchase design implemented for hydropower is a crucial element.

Batlle (2013) states that the particularity of the *"underlying commodity and the large diversity of typologies in electricity systems worldwide have led to the implementation of an enormous variety of alternative wholesale market designs."* Thus, the mode for remunerating hydropower varies from country to country, depending upon the level of market-based structures and the degree of unbundling[1]. Broadly, the approaches can range from centrally managed to wholesale markets.

In Brazil, market design for hydropower is organised around long-term contracts for electricity generation. Under the current regulatory design for the electricity sector in Brazil, the responsibility coordinating and monitoring the generation and transmission facilities within the National Interconnected Grid (NIG) is executed by an Independent System Operator (ONS)[2] (Francisco, 2012). ONS establishes and manages generation levels for each power plant, which is based on a mathematical program aimed at representing in detail the operation of hydro reservoirs. This mathematical program is solved using Stochastic Dual Dynamic Programming (SDDP) (Pereira and Pinto, 1991, 1985).

The *status quo* (until 2015) hydro generation remuneration framework is called Energy Allocation Mechanism (EAM). This consists of coupling the hydro players in a pool whose synergy would then reduce individual hydrological natural volatility within Brazil's river basins (RCBPS, 2002). This assumption strongly relies on the energy storage provided by the hydroelectric reservoirs and on complementary hydrologic regimes between some river basins.

However, there has been concern regarding the robustness of this current market design, mainly due to recent climatic conditions in Brazil (extended drought), increasing renewable penetration and the current economic crisis (MME, 2017). Once the hydro generators are engaged with long-term contracts and ONS regulates the dispatch of the system-contracted capacity, generators run the risk of EAM not

[*] Bruno Goulart has been awarded the first fellowship within FSR and ANEEL Research Exchange Program, and thus the authors would like to thank both institutions for the remarkable experience in Florence. They would also like to express their gratitude to Vinicius Grossi and Alex Alves, who provided crucial support regarding Newave's remote simulations. The authors would also like to thank Miguel Vazquez, Tim Schittekatte, Swetha Bhagwat, Tiago de Barros Correia, Luiz Augusto Barroso, Fernando Colli Munhoz and members of the FSR team for providing their valuable inputs as well as facilitating these results.

[1] Glachant et al., (2015)examine regimes for granting rights to use hydropower in fourteen European countries. Moreover Amundsen and Bergman, (2006) compare market structures in Nordpool with California, both having significant hydro resources and different experiences regarding power industry deregulation schemes.

[2] The responsibility of supervising and regulating ONS lies with the Brazilian Electricity Regulatory Agency (ANEEL) (Gomes and Poltronieri, 2018).

having sufficient energy production during adverse conditions to honour the sum of the correspondent market obligations.

Climatic conditions are identified to play a vital role in the inability of hydro-generators to reach their required generation levels (Coelho et al., 2016). The hydrological natural inflow regime in Brazil has a cyclic pattern lasting 10-15 years (Hunt. et al., 2018). The cycles consist of large periods of drought with low hydropower production (Almeida Prado et al., 2016). The recent drought in Brazil, which started in 2013, has caused severe financial distress to hydropower generators (Hunt. et al., 2018). According to recent bulletins released by the market operator (CCEE, 2018a), roughly 82% of the financial obligations within the market (around 1.7 billion of euros) were not cleared. Most of the non-clearances are attributed to judicial injunctions that have been issued to market players since the impasse regarding the hydropower pool's shortfall (ANEEL, 2015a; MME, 2017).

Thus, the hydro remuneration framework was diversified in 2015 by the introduction of a hedging mechanism as an alternative means of managing risk to the hydropower business model due to generation shortages. This mechanism is called the Insurance Call Option Obligation - ICO (ANEEL, 2015b) However, it is also important to highlight that EAM and FEC continue to co-exist and generators may choose the mechanism to which they wish to subscribe[3].

In this paper, we analyse and compare the performance of EAM and the ICO in three different long-term scenario settings, using an SDDP modelling methodology combined with a Monte Carlo approach. Performance is here addressed as the capability of the mechanism itself to provide positive economic outputs in the long-run. The key indicators used to assess the performance are thus the consumer utility and the hydro-generator utility in different scenario settings. An efficient allocation-design for the ICO is also addressed.

This paper is structured as follows: In Section 2 the hydropower market design of Brazil is presented. This is followed by the description of the modelling approach used for this research in Section 3. The scenarios and key indicators used are discussed in Section 4. The result from the modelling is analysed in Section 5. Finally, conclusions and policy implications are provided in Section 6.

2. Hydropower Market Design in Brazil and Policy Options

The hydropower market design in Brazil consists of three phases. Before the procurement auction (first step), the energy policy authority (MME) issues a firm energy certificate (FEC) for each power plant. According to Mastropietro et al., (2016), these certificates aim to ensure supply-adequacy within the regulated procurement environment (captive consumers) or within the wholesale market, where stakeholders trade energy.

As discussed by Maurer and Barroso, (2011)the calculation of FEC is a critical issue but at the same time, a complicated process, since it relies on the concept of firm energy. Georgakakos et al., (1997) define firm energy as "the energy ensured under adverse hydrologic and demand conditions". Thus, it is determined based on the critical hydrologic known period (i.e. the lowest long-term estimated production) of each generator when interconnected to the grid (Georgakakos et al., 1997), considering the synergy among them. Since the FEC is obtained via a probabilistic calculation, there is a risk of a mismatch between the actual and the *ex-ante* estimated production from hydropower (Barroso et al., 2003)

Furthermore, it is important to underline that the regulatory framework establishes that the FEC defines the cap each generator can trade in the market. Hence a straightforward hedge for each generator

[3] It is interesting to note that in literature several alternative market designs for remunerating hydropower in Brazil have been proposed by Calabria et al., (2018); Fernandes et al., (2018); Lino et al., (2003). However, these alternatives are not discussed in this paper.

would be not to commit the entire FEC with contracts, thus leaving some free margin to be eventually cleared in the short-term, depending on the system's conditions and each risk aversion criteria.

The FECs are then procured in the auction process (second step), where its final terms yield the price per unit generated settled in the contracts. The regulatory framework establishes that FECs must be the maximum trade commitment each generator must manage within its business strategy. This management may lead to hedge strategies each generator ought to be aware of, depending on its judgment regarding the inherent uncertainties of hydropower production.

EAM is thus a revenue adjustment mechanism applied in the last step, where hydropower trade commitments are contrasted with the plants' real production and the imbalances are measured and valued accordingly to the spot price. Although individual production risks may be relieved by EAM, this is still a component of hydropower business where uncertainty plays a core role.

2.1EAM status quo

The EAM is based on a virtual sharing principle that requires the calculation of a Generation Scale Factor (GSF). The GSF is a ratio between the actual sum of all *n* individual hydro production (Q_i) within EAM and the sum of the respective quantity of contracted FEC (FEC_i) over a set period *t* (usually one month). If the GSF value is greater than one, it would mean surplus production and *vice-versa.*

$$GSF = \frac{\sum_{i=1}^{n} Q_i^t}{\sum_{i=1}^{n} FEC_i^t} \tag{1}$$

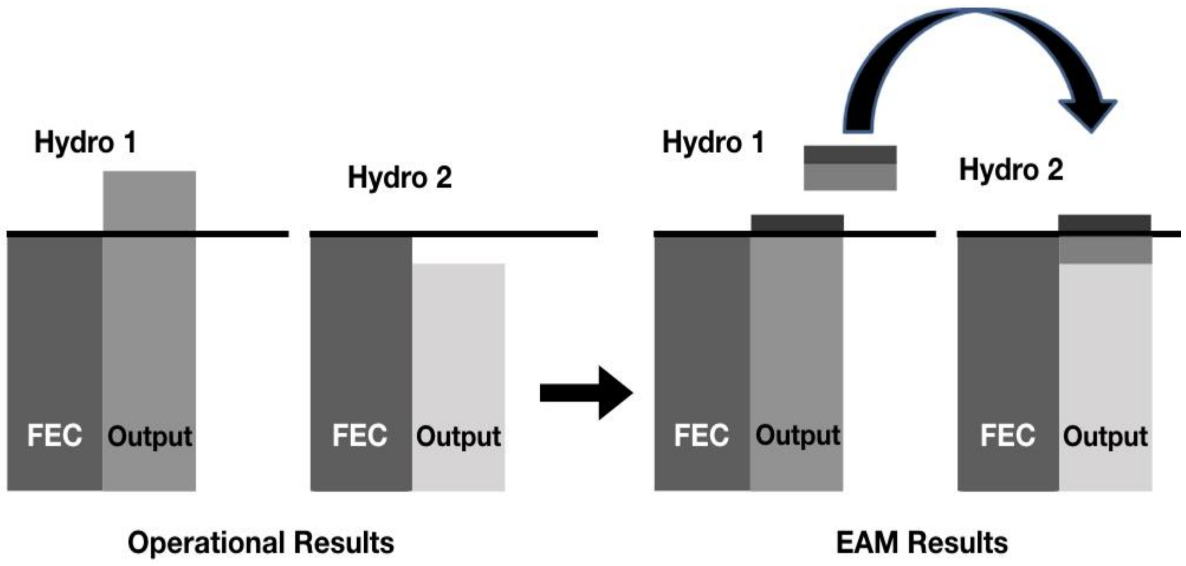
In Equation 1, it is assumed that all FEC within EAM was committed with contracts[4]. As stated before, the amount of electricity traded is capped by the FEC so that this value can be smaller in real-world strategies. The total income for the hydropower generator is dependent upon four variables, namely the spot price (p_{spot}), *GSF*, *FEC* and the auction clearing price (p_{bid}). Therefore, the total income (*Y*) is calculated as shown in Equation 2.

$$Y = \left[p_{bid} + p_{spot} \times (GSF - 1)\right] \times FEC \tag{2}$$

The EAM approach nets out individual imbalances and consequently reduces the risk for generators individually if there are negative correlations between the hydrological regime of the different participants or a long-term water storage capacity. Otherwise, it may increase the risk. Figure 1 illustrates a simplified EAM allocation procedure for two plants. Therefore, in the case of surplus generation (GSF > 1), all generators would receive additional income and *vice-versa*. The magnitude would be dependent on the spot price and the cumulative generation of the hydropower plants.

[4] This assumption does not compromise the analysis' robustness or its results since its major goal is to evaluate EAM performance by itself.

Figure 1 – EAM allocation framework



The following numerical example, based on the data from EPE, (2016), illustrates the functioning of this risk-share mechanism and its impact on the generator revenue. From the data, it is observed that the average auction clearing price (p_{bid}) was BRL197/MWh. In this same year, averages spot price (p_{spot}) and GSF were BRL317/MWh[5] and 0.79 respectively (CCEE, 2017). Using equation two and *ceteris paribus* all other variables, a 34% reduction in the generator's revenue (dY) would be noticed, again supposing that FEC had been entirely committed (100%) in trade contracts within the same period. A brief calculation of this example is presented below.

$$Y = [197 + 317(0{,}79 - 1)] \times FEC$$

$$Y = [197 - 66] \times FEC = 197FEC - 67FEC = 130FEC$$

$$dY = \left(1 - \frac{130FEC}{197FEC}\right) \times 100 = 34\%$$

2.2 Insurance Call Option (ICO)

As discussed in the previous section, in the status-quo EAM mechanism, the hydro generators share the risk of non-performance equally amongst themselves. Therefore, an individual generator is exposed to revenue risks that are beyond its generation capabilities. The insurance call option allows each hydropower generator to choose its level of risk exposure, thus making possible a revenue cap for EAM outputs, where the premium payment should pay off the avoided costs they would have to support in the status quo mode.

The ICO is another hedging mechanism introduced in 2015[6] to manage risk to the hydropower business model due to generation shortages. As previously defined by Merton et al., (1978), in the business environment, the functional characterisation of a call option is to be an insurance against a

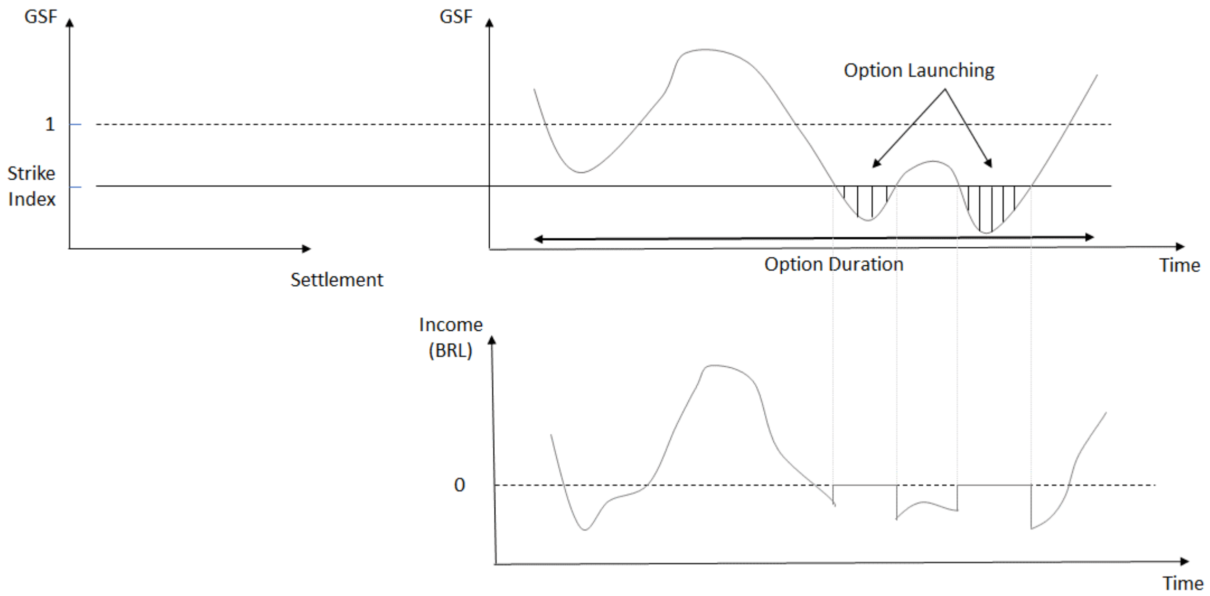
[5] After an application of a standard weighted average approach based on the four sub-markets relative share among total market size.

[6] The first one would be the amount of FEC each generator compromises within energy trade contracts. It is important to note that EAM and FEC continue to co-exist and generators may choose the mechanism to which they wish to subscribe.

decline in the underlying stock's value, where the investor can purchase the insurance without owning the asset. Like the traditional insurance contract, the call option price increases for larger coverage levels. The premium will also be higher for a longer maturity and coverage of a more volatile stock.

Eydeland and Wolyniec, (2003) describe the call options in the energy markets as *"the right, but not the obligation, to buy energy at a predetermined strike price"*. ICO follows the same fundamental approach for securing the hydropower production shortfall rather than a price. In Figure 2, a schematic example of ICO is displayed. It is important to note that, once the strike GSF is reached, the income for the generator is annulled until it returns to this same reference.

Figure 2 – ICO's framework – Generators' Perspective



ICO provides the hydro market with different pricing and risk sharing rates between generators and consumers, where ANEEL plays the insurer's role on behalf of the consumers (ANEEL, 2015b). The generator chooses the desired level of strike GSF to hedge its production risk and thus pays the corresponding risk premium.

There are two types of product portfolios, namely SP and P products. The SP products allow the consumers to keep the full benefits that arise when there are surpluses registered within the EAM operation (GSF > 1), while in the P products, all positive revenues remain with the generator. Hence, since P products have smaller deductibles (events with surpluses), their premium values are higher than that of a mirrored product in the SP category (i.e. products with the same risk shares). ANEEL sets the risk premium for both product portfolio. In Table 1 the options available to the generators are shown.

Table 1 – ANEEL's ICO main features

Product Modality	Secured GSF	Strike Index	Product Type	Risk Premium (BRL/MWh)
P	≥ 1	0	**P100**	12,75
P	≥ 1 and < 0,99	1	**P99**	11,75
P	≥ 1 and < 0,98	2	**P98**	10,75
P	≥ 1 and < 0,97	3	**P97**	10,00
P	≥ 1 and < 0,96	4	**P96**	9,00
P	≥ 1 and < 0,95	5	**P95**	8,25
P	≥ 1 and < 0,94	6	**P94**	7,50
P	≥ 1 and < 0,93	7	**P93**	6,75
P	≥ 1 and < 0,92	8	**P92**	6,00
P	≥ 1 and < 0,91	9	**P91**	5,50
P	≥ 1 and < 0,90	10	**P90**	4,75
P	≥ 1 and < 0,89	11	**P89**	4,25
SP	< 1	0	**SP100**	9,50
SP	< 0,99	1	**SP99**	8,50
SP	< 0,98	2	**SP98**	7,50
SP	< 0,97	3	**SP97**	6,50
SP	< 0,96	4	**SP96**	5,50
SP	< 0,95	5	**SP95**	4,75
SP	< 0,94	6	**SP94**	4,00
SP	< 0,93	7	**SP93**	3,25
SP	> 0,92	8	**SP92**	2,50
SP	< 0,91	9	**SP91**	2,00
SP	< 0,90	10	**SP90**	1,25
SP	< 0,89	11	**SP89**	0,75

ANEEL's price setting approach was to sum, to the average EAM historical record cost, the expected value from a set of uniform payments series where the second costly annual event known would be completely amortised (taken as an indirect measurement for consumers' risk aversion). The time-series set, in its turn, was designed to consider the occurrence of the costly event in each year of its 25-time-year horizon (ANEEL, 2015c)[7].

It is important to underline that ANEEL's ICO yields different EAM results among generators and consumers, depending on the modality of the insurance procured (SP or P), on the GSF strike (risk sharing commitment) and on the premium value itself. Thus, the same EAM outcome would yield two distinct positions: one for the companies, the other for consumers.

Hence, we may disjoint the second term of equation 2 into four sets, the first two related to consumers' revenue, also relying on whether it would be related to a P product ($\boldsymbol{Y_P}^{\boldsymbol{C}}$) or an SP one ($\boldsymbol{Y_{SP}}^{\boldsymbol{C}}$). The other two sets would be linked to the generator, both also committed to product's modalities ($\boldsymbol{Y_P}^{\boldsymbol{G}}$) or ($\boldsymbol{Y_{SP}}^{\boldsymbol{G}}$). In these equations, *pay* represents premium value and GSF^{stk} the strike GSF.

$$Y_P^C = \begin{cases} pay & GSF \geq 1 \\ pay & GSF < 1, GSF \geq GSF^{stk} \\ [p_{spot} + pay] \times [-1 + GSF] \times FEC & GSF < 1, GSF < GSF^{stk} \end{cases} \tag{3}$$

$$Y_{SP}^C = \begin{cases} [p_{spot} + pay] \times [-1 + GSF] \times FEC & GSF \geq 1 \\ pay & GSF < 1, GSF \geq GSF^{stk} \\ [p_{spot} + pay] \times [-1 + GSF] \times FEC & GSF < 1, GSF < GSF^{stk} \end{cases} \tag{4}$$

$$Y_P^G = \begin{cases} [p_{spot} - pay] \times [-1 + GSF] \times FEC & GSF \geq 1 \\ [p_{spot} - pay] \times [-1 + GSF] \times FEC & GSF < 1, GSF \geq GSF^{stk} \\ -pay & GSF < 1, GSF < GSF^{stk} \end{cases} \tag{5}$$

$$Y_{SP}^G = \begin{cases} -pay & GSF \geq 1 \\ [p_{spot} + pay] \times [-1 + GSF] \times FEC & GSF < 1, GSF \geq GSF^{stk} \\ -pay & GSF < 1, GSF < GSF^{stk} \end{cases} \tag{6}$$

Consider the following example for ease of understanding: If a generator chooses the P99 option, it must pay a premium of 11.75 BRL/MWh, while its insurance covers every EAM output whose GSF is less than 0.99. Since it is a P modality procurement, every event whose GSF is equal to or greater than 0.99 (including the ones with surpluses, GSF >1) remains as part of the generator's ordinary revenue. Meanwhile, if the generator chooses an SP99, it will pay a lower premium of 8.50 BRL/MWh, while its protection against shortages would have the same coverage as a P99 case. The difference resides in the revenue from surplus events. In the SP99 scenario, the generator will not receive any income from surplus events, as they are now part of the consumer's saving.

3. Model Description

For this analysis, a similar approach as the one adopted by the Brazilian government for issuing FEC grants to hydropower plants is followed. Hence, SDDP simulations with Newave, the Brazilian official computational tool (Maceira et al., 2008), were run in its static mode. This means that the system's seasonal boundary conditions, such as load, transmission lines and power plants capabilities and constraints, RES generation, are all previously fixed and kept constant throughout the optimisation time horizon.

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7 This was the average remaining concession period for existing hydropower assets by the time the regulation was issued.

The static simulation approach is preferred for determining FEC in Brazil because such an approach is strictly related to the definition of firm energy. In the Brazilian context, firm energy is a key issue for assessing the hydropower system's supply reliability and hence adopted as a structural dimensioning parameter (República Federativa do Brasil, 2004). The aim here is not to evaluate the system's short-term supply adequacy, influenced by the system's boundary conditions dynamics and interactions. Instead, it is to assess its average performance in a broader range of operational scenarios, seeking to check whether key operational outputs meet the planning criteria established by the national energy council (CNPE, 2008).

Indeed, the concept of firm production capacity is old (Arvanittdis and Rosing, 1970) and it is linked to the capability to generate electricity in a natural sequence of dry years (Lima et al., 2016). It also relies on the calculation of the maximum continuously amount of energy that can be produced by the entire hydro pool, with their synergy operational benefits and all their operational constraints being coordinated by a centralised operator. Furthermore, (Labadie, 2004) presents several approaches to modelling firm production capacity founded in the literature.

Nonetheless, the firm energy is usually calculated through an iterative process (Faria et al., 2009). For a given energy demand over a period, the hydro system optimal policy is determined, where any energy deficit is thus computed (Faria et al., 2009). Whether this deficit violates a pre-determined cap, the demand is reduced until it stays below the maximum reference. Otherwise, the demand is increased. In order not to have this analysis affected by the system's short-term boundary conditions, static simulations are employed. Hence while dynamic simulations yield a short-term supply-adequacy overview, usually applied for plants' dispatch and spot market pricing, static simulations seek to provide a broader panorama for the system's reliability in the long-run.

Within the current regulatory framework (MME, 2016), a static simulation is applied with the NEWAVE model as follows: for a given average energy demand, fixed within a 5-year-period, an SDDP routine is carried out until the average marginal operational costs (MOC) meet the marginal expansion cost (MEC)[8] , and the average shortages stay under 5% of the system's total load. If both boundary conditions are not met, a new load is established. The iteration for load continues until the maximum load level, which simultaneously follows the two caps, is reached. Arvanittdis and Rosing, (1970) defined this final demand as a critical or firm load.

The equivalence of marginal operational costs and marginal expansion cost assures that, on average, the system expansion's costs, whose expenditures are the sum of the operational costs plus the new investments, are economically equivalent to the current ones. This assumption turns the SDDP simulations compatible to each other (i.e. their outputs are under the same economic equilibrium), despite not having the same load or mix shares and results being necessarily derived from the same optimal policies. A concise mathematical formulation of the SDDP algorithm is presented below, based on Pereira, (1989).

$$\alpha_t(X_t) = \underset{(A_t|X_t)}{E}\left[\min_{U_t}\left(C_t(U_t) + \frac{1}{\omega}\alpha_{t+1}(X_{t+1})\right)\right] \forall t = T, T-1, \dots, 1 \forall X_t \quad (7)$$

Subject to

$$X_{t+1} = f_t(X_t, A_t, U_t) \quad (8)$$

$$g_{t+1}(X_{t+1}) \geq 0 \quad (9)$$

$$h_t(U_t) \geq 0 \quad (10)$$

8 At the reference date of this work, MEC was BRL193/MWh. There is a tolerance of BRL2.00/MWh for this match, where BRL is an acronym for the Brazilian currency.

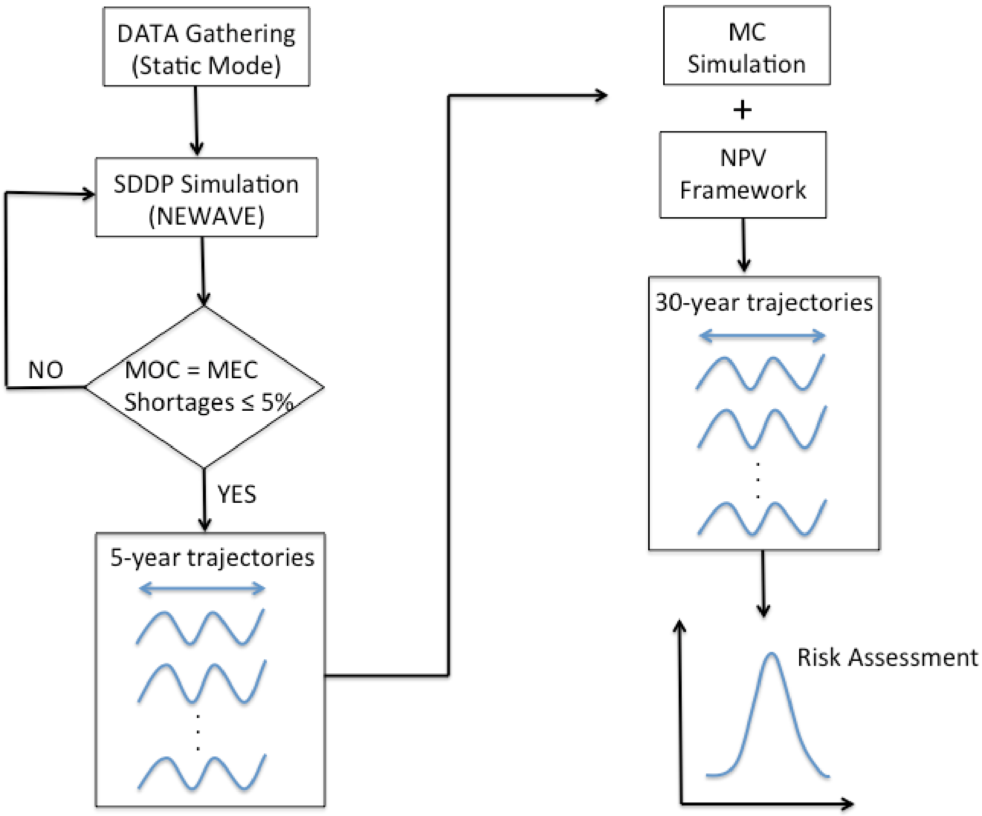
Where t indexes the stages (T planning horizon, which is 60 months for FEC problem) X is a vector that represents the state variables. $\alpha(X)$ denotes the expected value of the operation cost throughout the planning horizon under the optimal operation policy. $A \mid X$ represents the probability distribution of the inflows A, conditioned by the state X, $E(.)$ is the expected value operator. U the decision vector for each stage, $C(U)$ the immediate cost related to the decision U, ω the discount rate, $f(X,A,U)$ the state transition equation, $g(X)$ the set of constraints on the state vector and $h(U)$ the set of constraints for the decision vector (Pereira, 1989).

Since the hydropower concession grant period is 30 years and the FEC planning horizon is 60 months (five years), an extension period over FEC's common outputs had to be addressed. Hence a Monte Carlo (MC) simulation (Shapiro, 2003) was applied to the optimal policy originally released by Newave. Generally, the evolution of the power system along the stages has a tree-like structure, where each branch corresponds to an alternative solution to the problem presented in Equations 7-10 (Pereira, 1989). Several operational trajectories may occur throughout the default horizon of five years since the SDDP routine had been converged.

The MC approach entails randomly coupling six samples from each of the optimal policy trajectories output by Newave. That would be just an expansion of the original horizon which aims to mimic system's long-term scheduling. If we assume that the original decision-tree had been sufficiently explored (i.e. its combination of operational policies may be a reliable subset of the countless optimal possibilities that may occur in real practice) and that the electricity mix share might be somewhat considered representative for the system's evolution throughout the future period under consideration.

The convergence of the MC procedure was evaluated following an approach suggested by Yang, (2011), basically adopting the coefficient of variance (CV) as an indicator to control MC convergence. We assumed that a difference of less than 1% in the CV for EAM releases was negligible. Also, a Net Present Value (NPV) approach was utilised to assess the impact on consumer and generator economics utility. ANEEL's yearly regulatory weighted average cost of capital (WACC) of 9.63% (ANEEL, 2015c) was used for these calculations. Figure 3 illustrates a schematic flow of the methodological approach that was addressed.

Figure 3 – General Model Description



The first step was preparing the input files required by Newave for each of the three scenarios, whose data and details will be described in the next section. After that, a loop routine with Newave simulations was carried out observing the description made in Section 3, until the convergence criteria had been met. This procedure led to two thousand exemplars of 5-year optimal policy sequences. Their horizon-extension was made by applying the MC technique, which consisted of randomly sampling six exemplars of the five-year-sequences and then coupling them in a row, yielding thirty-year optimal policy trajectories. A regulatory discount rate (WACC) is applied to each element of the thirty-year sequences, whose NPV's statistical properties were the base for indicators' formulation and the following risk economic analysis.

4. Scenarios and Indicators

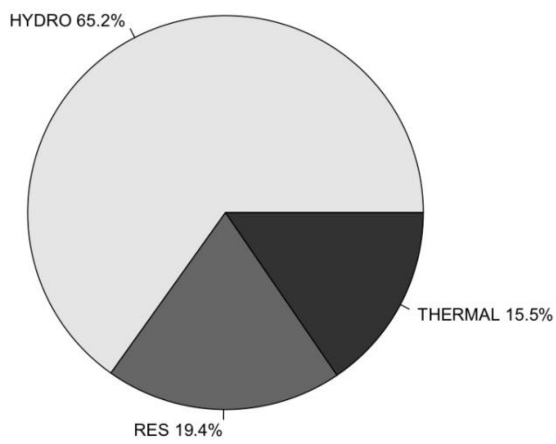
Three scenarios have been used to assess the economic performance of the EAM. The first one (baseline scenario) consisted of evaluating the current system configuration. The second scenario was based on the most recent reference expansion roadmap published by the Brazilian government (EPE, 2017a). The third was a what-if scenario, also extracted from the official plan, where no new hydro plant would be built within the planning horizon.

An important aspect regarding scenario selection was to evaluate official outlooks rather than make arbitrary choices. This enabled the authors to yield relevant policy insights that are based on the Brazilian energy authorities' conceived vision of the future. More details for each of these will be provided in the next sections.

4.1 Scenario 1 (Baseline)

This scenario is based on an EPE, (2017b) supply-adequacy study that was carried out throughout 2017, using the system's consolidated data from 2016, but with its operational and economic effects only in 2018. The generation mix share considered is presented in Figure 4. The technologies were merged into three main themes: Hydro, Thermal and RES. These data also include all previously procured assets whose trade operations shall start within the 2016-2026 horizon.

Figure 4 – Mix Share in 2016 (Total Installed Capacity of 148GW)



4.2 Scenario 2 (RES26)

This scenario is based on the mainstream roadmap released by the government (EPE, 2017a). So it is a recent indicative reference about the system's expected expansion. It indicates a significant increase in the share of RES, with more than 23.5 GW of new assets being procured by 2026. RES is indeed forecasted to form 30% of the electricity mix share by 2026. Figure 5 illustrates the ten-year expansion trajectory for the three merged technologies, as well as the mix share evolution based on the average generation.

In this outlook, new hydro assets procurement has also been considered, as the government expects to launch some new hydro plants within the planning horizon. The selection of hydro expansion is based on previously observed technical, economic and environmental parameters provided by public inventory data[9] that best fitted the expansion optimisation criteria (EPE, 2017a)[10]. The list of best indicative plants is presented in the Annex. One common and essential feature among them is that all are run-of-river hydroelectric plants. The total new installed capacity of hydroelectric plants would be of 2.6 GW.

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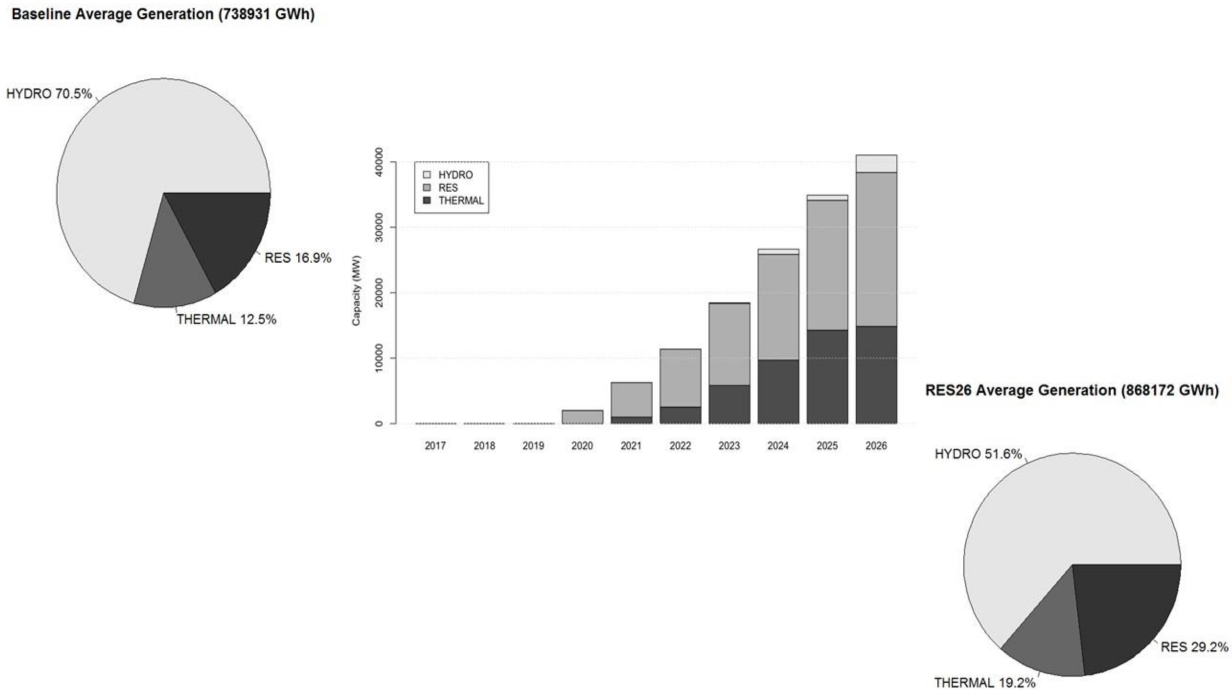
9 A public repository where one may find results of optimal hydropower river basin exploitation studies, all them approved by the Regulator, whose data publicity is fully available.

10 Whose objective function is to minimize total investment plus operational costs, subject to the main operational restrictions for the load attendance. A more complete description of the model is provided by EPE, (2017a).

Figure 5 – Mix share evolution and the Ten-Year Expansion Plan

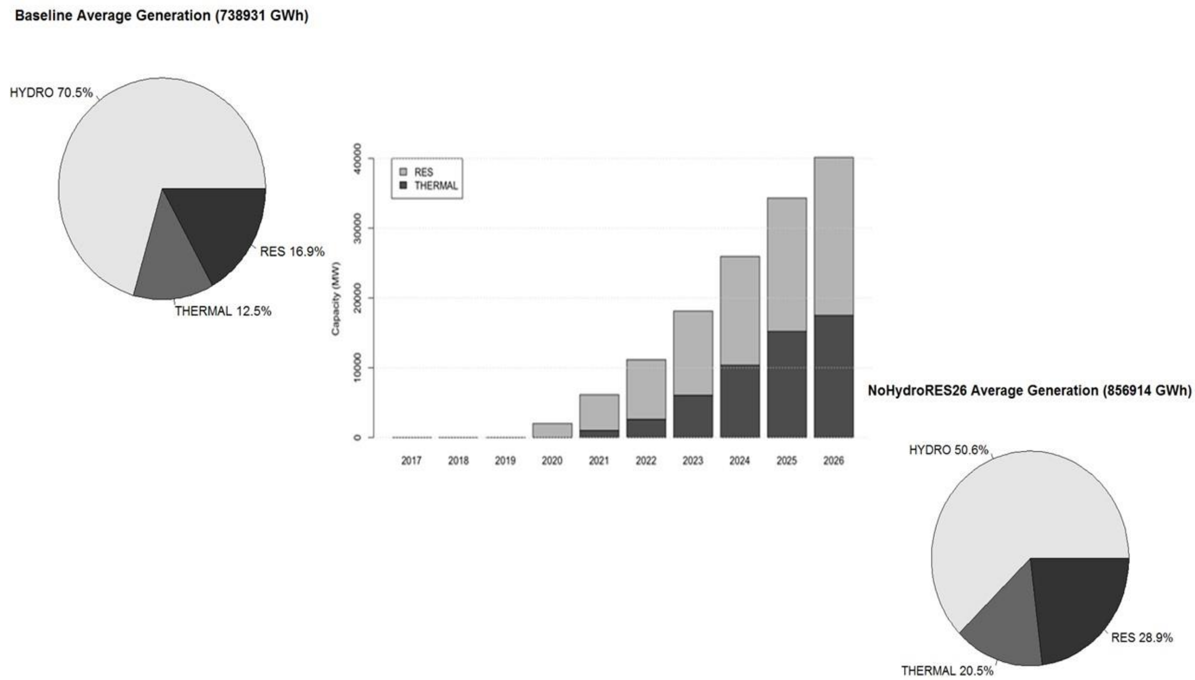


4.3 Scenario 3 (NoHydroRES26)

The official expansion plan also provides a what-if scenario that assumes complete restrictions on building new hydro plants throughout the planning horizon. This is a relevant scenario in Brazil considering the current social and environmental constraints for developing new hydro projects, which are adding to the energy source investment and operational costs. Indeed, higher development costs and risks are nudging developers to explore and opt for alternate hydropower solutions (Ansar et al., 2014).

The NoHydroRES26 scenario would lead to the construction of 2GW of new coal plants, whose unitary costs would be of 100BRL/MWh (EPE, 2017a). Regardless of the increase in greenhouse emissions, their affordable operational costs and national availability would make them more attractive according to government's expansion criteria. In the context of RES, the source would have a small relative decrease of 1.4% in the mix share (22.6GW). Mix evolution is presented in Figure 6.

Figure 6 – Mix share evolution and the "no hydro" scenario within the Expansion Plan



4.4 Other variables

All other variables used in the analysis can be checked in EPE, (2017a) and EPE, (2017b). We highlight in Table 2 the most relevant ones. Recall that the equivalence of marginal operational and expansion costs ensures that the three scenarios are comparable to each other, despite not holding the same average load or the same mix shares. Nevertheless, the same load trend has been applied in both future outlooks, which is why RES26 and NoHydroRES26 present the same average load. Finally, also to keep the results compatible with each other, the same discount rate has been applied within each NPV simulations horizon.

Table 2- Other Variables used in the analysis

<table>
<tr><th>Scenario</th><th>Average Load (MW_{avg})</th><th>Load Annual Average Trend (%)</th><th>NPV Annual Discount Rate (%)</th></tr>
<tr><td>Baseline</td><td>67.309</td><td>-</td><td rowspan="3">9,63</td></tr>
<tr><td>RES26</td><td rowspan="2">92.447</td><td rowspan="2">3.5</td></tr>
<tr><td>NoHydroRES26</td></tr>
</table>

4.5 Indicators

In the analysis, it is key to understand that we discuss only the second term of equation two, since the first part (bid price and the FEC) may to some extent be considered flat elements within hydropower revenues. We are particularly interested in a subset of equation two's second part, which defines EAM operational unit values (EAM_{uv}):

$$EAM_{uv} = p_{spot} \times [GSF - 1] \tag{11}$$

EAM_{uv} indicates the difference between actual revenue the hydro-generator would earn if compared to the expected revenue entirely based on FEC. If GSF is less than one, EAM_{uv} would be a negative indicating a deficit and *vice-versa*.

Furthermore, since EAM results rely on the stochastic properties of the system operation, EAM_{uv} was the variable computed using the methodology described in Section 3. The WAAC discount rate was applied to each EAM_{uv} operational cash flow time-series over the defined horizon (30 years). Moreover, since this framework yields 80.000 net present values for EAM_{uv}, the 5% quantile (Q_5) of the respective probability density was used to establish a benchmark reference.

From the generator perspective, a negative Q_5 value would mimic a conservative hedge price-cap that entrepreneurs would be likely to pass-through in their project finance to protect it from EAM dynamics[11]. Conversely, a positive value would be a reference of the maximum discount hydro generators would be willing to bid (P_{bid}) to have the right to run the hydro asset business. From the customer side, Q_5 could be taken as an indirect measurement of consumer's utility (impact on the electricity tariff), since this hedge (positive or negative) ought to be partially or entirely reflected in the P_{bid} price settled in ordinary auctions carried out in the regulated environment.

In this research, we opted to focus on a straightforward interpretation of Q_5 within consumers' economic positions: i) If consumers are enrolled with EAM outputs (policy option 2), their economic utilities would correspond to Q_5 measured within each of the two incomes modalities, Y_P^C or Y_{SP}^C. ii) If consumers do not have a direct enrolment[12] within EAM operation (policy option 1), Q_5 ought to be always null. Finally, combining consumers' and generators' economic utilities would yield a measurement for the market's effectiveness, here stated as a market utility.

5. Results and Analysis

5.1 EAM Status Quo results

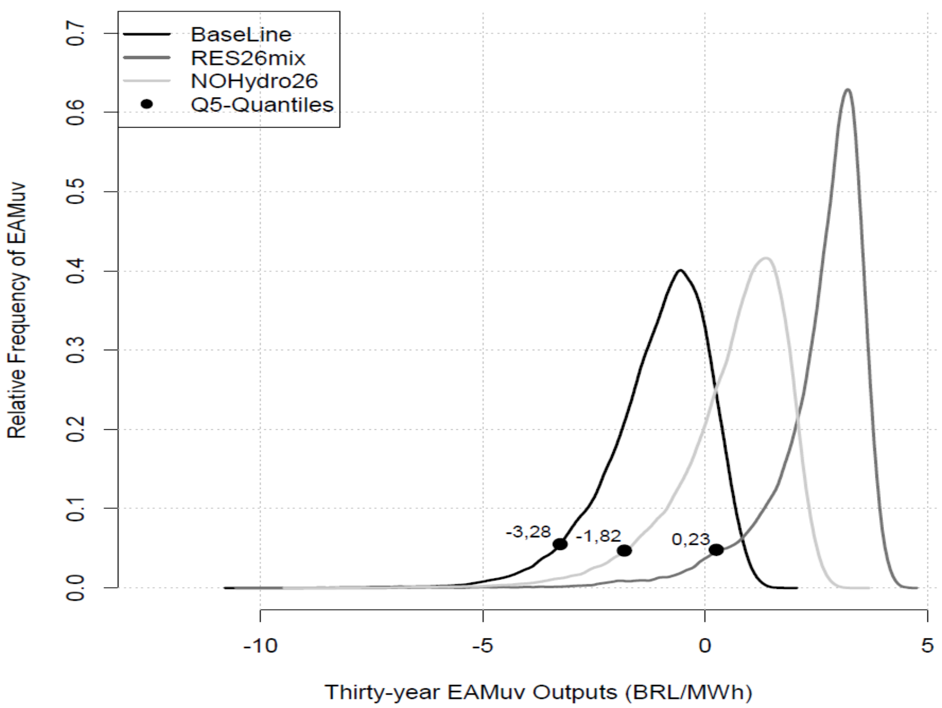
Based on the methodology described in Section 3, the EAM *Status Quo* results from the model are presented[13]. The simulation indicates that, in the baseline scenario, the EAM would more likely drive a negative impact on the revenues of the hydropower generators. The results suggest a probability of only 18% of having a positive NPV over the given time horizon. Conversely, the RES26 scenario shows a 97% probability of positive NPV and, in the NoHydroRES26, the same metric would be 76% (See the probabilities densities in Figure 7).

[11] Indeed, a very important issue regarding this subject is the setting firm's willingness to take risk in specific markets, which is a fairly complex subject (de Maere d'Aertrycke et al., 2017). The assumption made here (adopting the 5% quantile) was an empirical choice, whose aim was to focus more on the policies' general implications rather than their specific complexities, especially setting a common base where comparison between different designs could be done.

[12] We mean direct enrolment because EAM performance should indirectly affect p_{bid} (and thus tariffs) within the regulated environment since its economic feasibility is a relevant part of any hydropower project finance.

[13] Model validation results using historical data for comparison are provided in the Annex.

Figure 7 – EAM Economic Performance



It is important to remember that, in both future scenarios, RES expansion is similar (difference of 1.43%). The main difference was the substitution of 2.6GW of hydro plants for 2.4GW (2GW coal) thermal sources in NoHydro26. Hence, we may conclude that slight differences among the expansion portfolios, especially related to the controllable sources share (i.e. substituting non-controllable run-of-river hydro plants for controllable thermal), may yield substantial differences regarding EAM output ranges and frequencies. From the three probability densities within the horizontal axis in Figure 7, it is observed that the corresponding spectrum and shapes varied significantly between the three scenarios.

The consumer and generator utilities values in the three scenarios are also displayed in Figure 7. The economic imbalance for EAM in the baseline is also reflected in its utility value since Q_5 was a negative value of BRL -3.28/MWh. As stated before, this can be interpreted as the cap hedge price a hydro generator would be willing to pass-through in his auction strategy to mitigate EAM risk operation within his business. The deviation of the utility measurement, either positive or negative, would be partially or entirely considered by generators in their final auction bid and thus be reflected in contracts' prices traded between generators and consumers within the regulated environment.

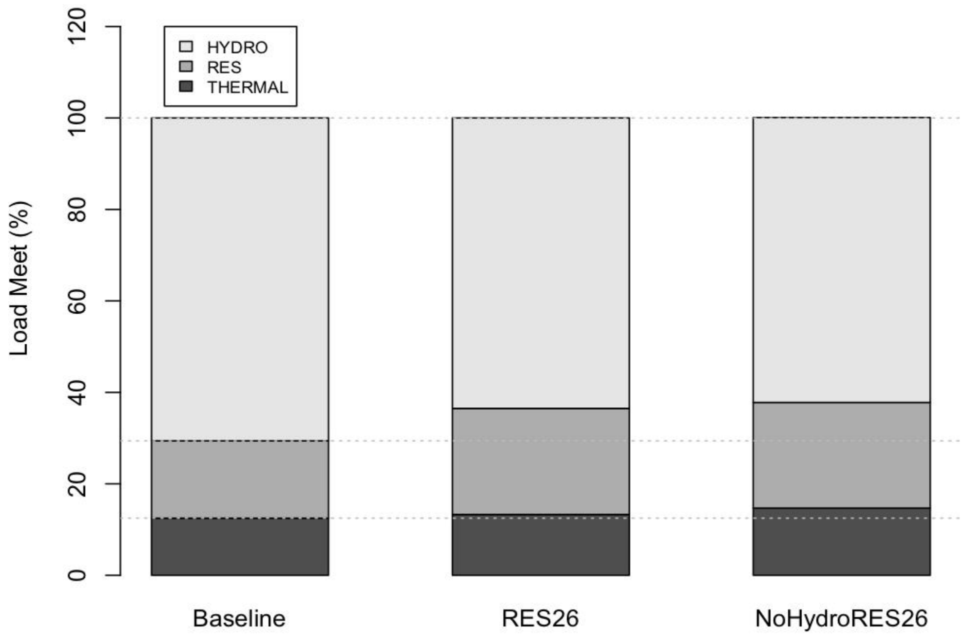
In the RES26, on the other hand, we observe that hydro generators would likely to have a positive impact of BRL0.23/MWh on their welfare. Consequently, not only benefiting the hydro-generators directly but also the consumers indirectly, since this could be the maximum discount a generator would be willing to offer in its bid strategy to be more competitive in the auction process. NohydroRES26 scenario, in its turn, would yield an intermediate pattern, where there would still have a negative perspective regarding hydro pool performance in the long-run, here measured as BRL -1.82/MWh. This last outcome was mainly driven by the substitution of the run-of-river hydropower for coal plants, whose unitary costs of BRL100/MWh would likely yield them to be a load-based source in most of the operational scenarios[14], thus directly competing with controllable hydro sources (hydroelectric with reservoirs) for the preferable dispatch.

[14] Yet since average MOC had been previously settled equal to BRL 193/MWh, coal unitary costs are far under this central reference, what thus turn them to be a load-based dispatchable source.

5.1.1 Impact of generation mix features on EAM results.

The average simulation outputs are presented in Figure 8. In the chart, relative RES participation is structurally higher in both future scenarios (RES26 and NoHydroRES26) as compared to the baseline. Nonetheless, RES installed capacity might be considered quite the same in the two cases (see Section 3.3), what yields similar results regarding generation share and meeting load requirement. Furthermore, although hydro and thermal relative participation is more or less the same in future scenarios, EAM densities shown in Figure 7 differ significantly from each other. Hence, it can be concluded that the participation of RES at the currently forecasted levels does not have a significant impact on the EAM risk matrix and thus its economic performance.

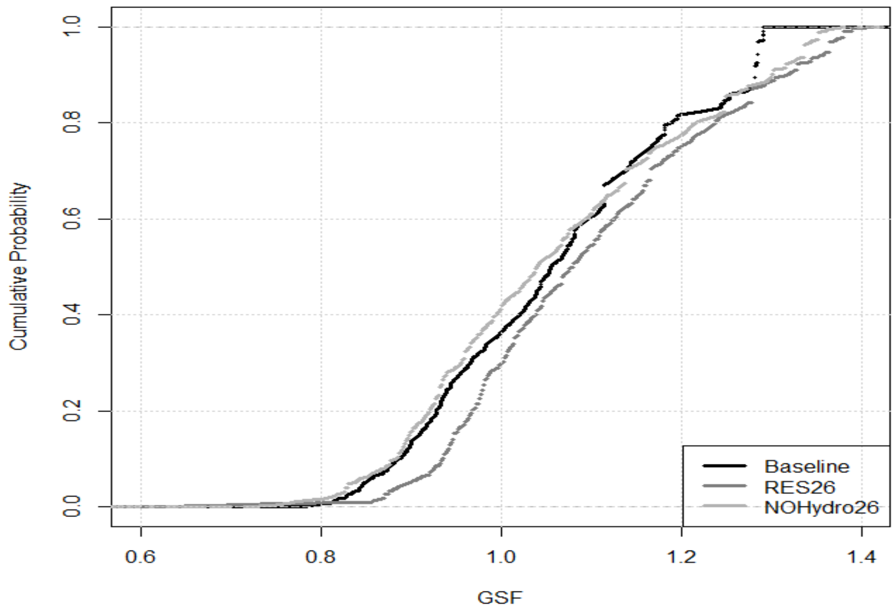
Figure 8 – Average Mix Generation Share



The role of the main features related to EAM risk dynamics can be better understood when comparing EAM indexes in a broader range of results (Figure 9). Looking at these outcomes, we realise that there is a relatively higher hydro generation in the RES26mix scenario than in the other two, for almost every operational trajectory. Taking also into account that RES growth would be similar in both future conditions, the increase in hydro production in RES26 could be attributed to the presence of more non-controllable sources (what includes RES technologies and run-of-river hydro plants) instead of thermal sources as in NoHydroRES26.

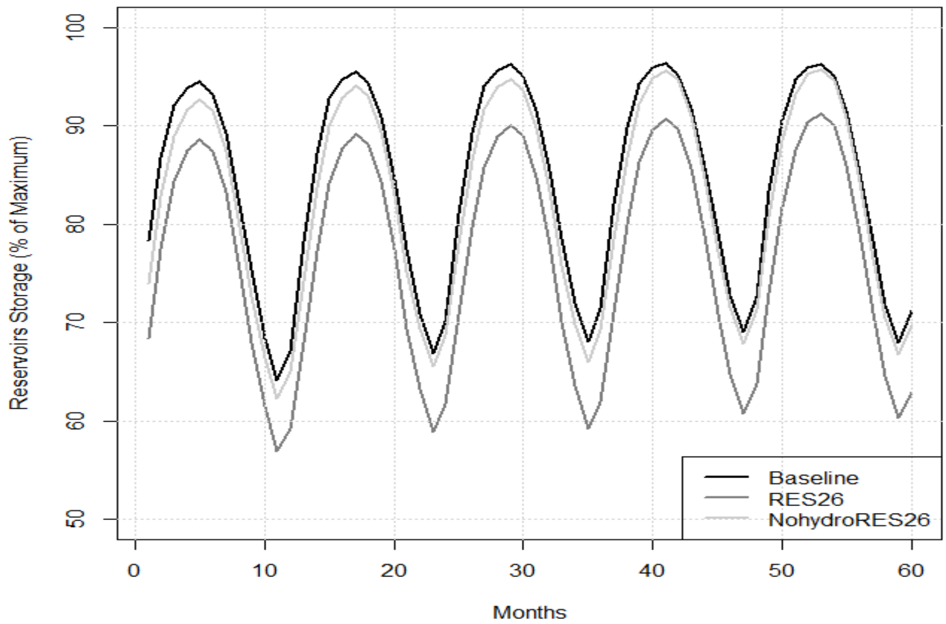
When RES26 and NoHydroRES26 generation expansion quantities are compared, the former would have more non-controllable sources (+2.6GW of run-of-river plants), instead of low-cost coal thermal (+2GW). Thus, having less controllable thermal supply raises the RES26 hydro generation's pattern to a higher level compared to the baseline scenario. On the other hand, because no hydro asset is foreseen in NoHydroRES26, the opposite effect (GSF structural decrease) is observed in this outlook, making the system more reliant on thermal generation assets.

Figure 9 – GSF indexes



Reservoirs average storages also corroborate these remarks. This result is presented in Figure 10. We may realise that reservoir depletion is structurally higher (lower average levels) in RES 26 than in the other two. Meanwhile, NoHydroRES26 reservoir average storages follow the baseline pattern very closely.

Figure 10 – Reservoir Average Storages

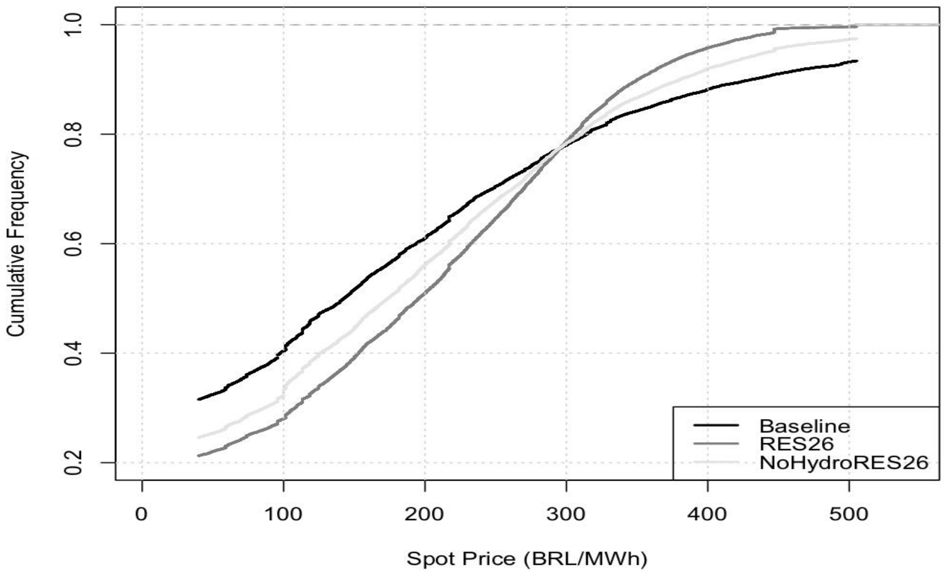


Since hydro performance was much more sensitive to thermal growth than to RES augment, we may conclude that RES penetration itself, on average, might not have significant influence over EAM long-term performance. For instance, comparing NohydroRES26 with the baseline, despite the increase of 12% in RES mix share (+22.6GW), the hydro dispatch in both cases was very similar. Indeed, as long as the system's increment of demand might be fully met by expansion of RES (this also may include run-of-river hydro assets), the net demand to be supplied by controllable sources (i.e. water reservoirs and thermal power) stays the same, thus not interfering in the optimal scheduling decision-problems' boundary conditions.

5.1.2 Impact of generation mix features on spot price

In Figure 11, spot price cumulative probabilities are presented. While RES26 has the most evident difference compared to the baseline, NoHydroRES26 presents an intermediate pattern. Before analysing the main causes for this observation, an important feature to highlight is that the three curves have the same average value since they were all derived from an optimisation procedure whose MOC had to be equal to MEC (See Section 3). This parity is vital to make them comparable with each other, as they all simultaneously tend towards the same economic criteria.

Figure 11 – Spot price Cumulative Probabilities

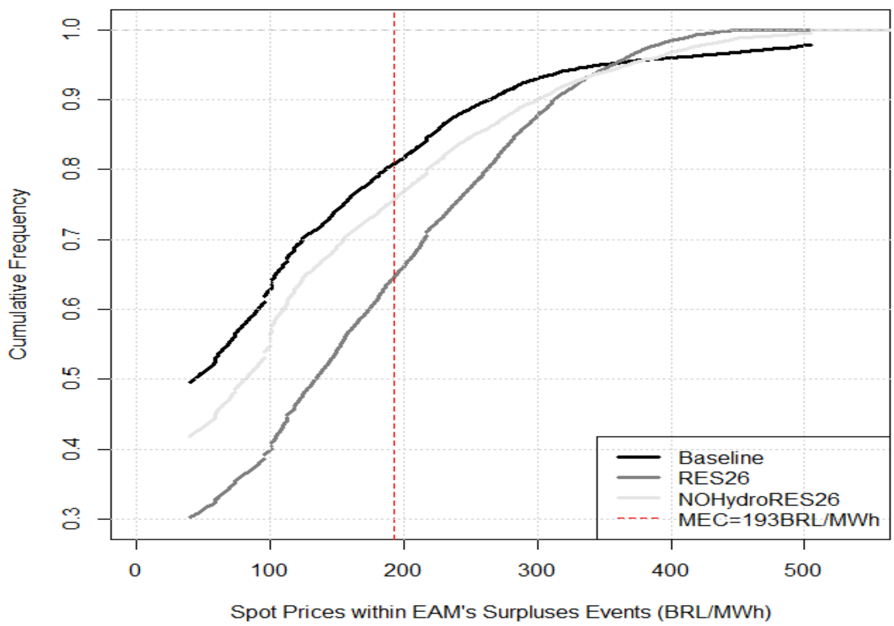


An essential remark from the spot price's statistical properties shown in Figure 11 is that the futures scenarios display higher slopes than baseline's, until a price near BRL300/MWh. After this reference, the slopes' trends shift. This is relevant because surplus events within EAM usually happen within the lower tail of the spot price cumulative distribution function. Surplus events are likely to happen when both reservoir levels and hydrologic inflows are favourable, thus driving water values and MOC downwards.

Conversely, EAM deficits are likely to happen when water values and MOC are at their higher pattern. If so, we conclude that the slopes of future cumulative probabilities, especially in RES26, improve EAM economic performance in its two strands: surpluses are more highly valued, while deficits are less penalised. However, the key is to understand the reason behind this occurrence.

In Figure 12 a subset of the spot price cumulative distribution is displayed, where the curves group the only spot price that is linked with EAM surplus events. From the graphs, we can realise that most of these events occur when the spot price is below the MEC reference. Moreover, RES26's spot price is far greater than in the baseline, within almost 95% of the probability spectrum. This is related to thermal supply curve shapes and might be considered as a core reason for the EAM economic performance improvement observed in RES26 scenario, particularly compared to the other ones.

Figure 12 – Spot price within EAM's Surpluses Events



From Figure 11, it is observed that the price near of BRL300/MWh appears to be an important inflexion point within all these scenarios, where both future cumulative probabilities functions shift from being higher to lower, compared to the benchmark reference (baseline). This is a price reference where thermal supply curve shapes have an almost 90-degree slope, whose unitary costs shift from approximately BRL300/MWh to above BRL400/MWh (see Figure 13).

Indeed, due to the strong correlation water values and MOC have with thermal supply curve characteristics (Pereira *et al.*, 1998)[15], a great augment of the thermal unitary costs in any part of its power availability domain might enhance hydropower generation in the correspondent range of the operational costs interval. Hence, the point where any singular inflexion occurs within the thermal supply dominium is crucial for the final relative energy allocation between hydro or thermal sources. For instance, in the future scenarios here addressed, the 90-degree-slopes are close to thermal's relative usage of 50% (percentage of thermal power availability regarding its full capability), whereas, in the baseline, this represents more than 75%.

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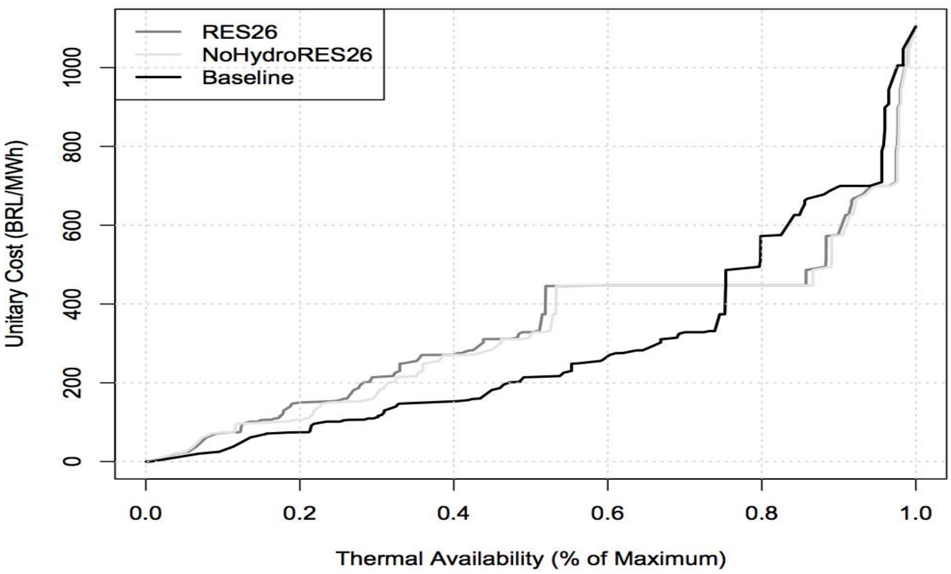
15 Indeed, hydrothermal systems' optimal scheduling is a problem coupled in time (a decision in present affects operating costs in the future), which thus deals with minimizing current and future costs. The latter is the opportunity cost associated with savings in displaced thermal generation now or in the future (Pereira, 2000). Water values might be interpreted as the derivates of the immediate or the future costs functions with respect to storage in the reservoirs. Mathematically, these are the simplex multipliers (shadow prices) derived from the water balance equation, one of the specific constraints contained in the set of state transition equations generally resumed in Equation 8. The optimal usage of the reservoirs is at the point which equalizes immediate and future water values.

Figure 13 – Thermal Supply Curves



Another important feature is that if MEC is taken as an empirical reference for measuring thermal base-load relative participation within the power mix, we realize that, in the baseline scenario, almost 50% of the thermal portfolio has unitary costs below this reference, whereas, in the two future scenarios (RES26 and NoHydroRES26), this same reference is near 30%. This relative decrease certainly contributes to pushing hydro prevalence among the preferable dispatch and thus EAM performance.

Furthermore, RES26 and NoHydroRES26 thermal supply's curves show significant plateaus next to the BRL450/MWh unitary cost. This feature comes from more than 12GW of thermal gas-fired plants foreseen in the plan (EPE, 2017a). This significant thermal volume above CME makes their portfolios relatively more expensive compared to the baseline. The influence of these elements over thermal dispatch is presented in the Annex.

Therefore, it is observed that slight differences in thermal supply curves cause significant consequences over optimal hydrothermal allocation. This last statement leads to at least an important remark. How important might thermal generation's physical and economic features be for hydropower dispatch and thus on EAM economic performance. From the results shown, small differences in RES26 and NohydroRES26 thermal's supply power availability and unitary costs caused relevant differences in spot price realisations and the hydrothermal optimal trade-off quantities. These are the core variables regarding EAM economic performance (See Equation 11).

5.2 Insurance Call Options Results

The results from the implementation of ICO in the three scenarios are presented in Figure 14. In all graphs, lines represent the expected value for EAM outputs and, the shaded area, the confidence interval of 90% for the same variable. Moreover, for ease of comparison between the two policy options, the utility indicators for the ICO approach are presented in Tables 3 to 5.

From Figure 14 it is observed that the confidence intervals for consumers' economics positions are larger than the same for generators. Furthermore, SP modality provides less volatility to generators than the mirrored P product. This is because the EAM surpluses are not part of generators' revenue when they opt for any SP product. SP100 is insurance whose coverage ensures complete flat revenues for generators onwards. Indeed, SP100 works as a hedge premium the generator would be willing to pay aiming to keep EAM uncertainty entirely out of their hydropower business.

Another conclusion is that ICO’s design does not yield perfect monotonic behaviours within GSF strike’s range. The original trends observed in most of EAM economic outputs displayed in Figure 14 (i.e. decreasing utilities for consumers while strikes values grow, or the opposite, for generators) start to shift its initial tendency within its default dominium (strikes vary from zero to eleven). When this happens, the premium value no longer reflects the risk supported by the insured (generator). Therefore, there is a scope for the insurance improvement design.

Furthermore, because each curve in Figure 14 shows an inflexion within their shape (non-monotonic function), they end up representing local optimal points. Hence the inflexion points in each generator and consumer curves represent the optimal trade-off between risk share and net expected return, according to their perspective, thus each becoming its own reference for assessing the attractiveness of the insurance options.

It is also observed that the ICO performance differs depending on the scenario. In baseline and NoHydroRES26's trajectories, for instance, P92 maximises generator returns, while in RES26, P89 would be the preferable choice. This can be explained by the improvement in EAM economic performance that is driven by RES26 mix’s boundary conditions (see the previous Section). Since EAM would likely yield positive NPVs in this case, it would make managing EAM negative outputs less costly, which would make the maximum strike GSF (equal to eleven) the most suitable choice.

Figure 14 – ANEEL's ICO Assessment

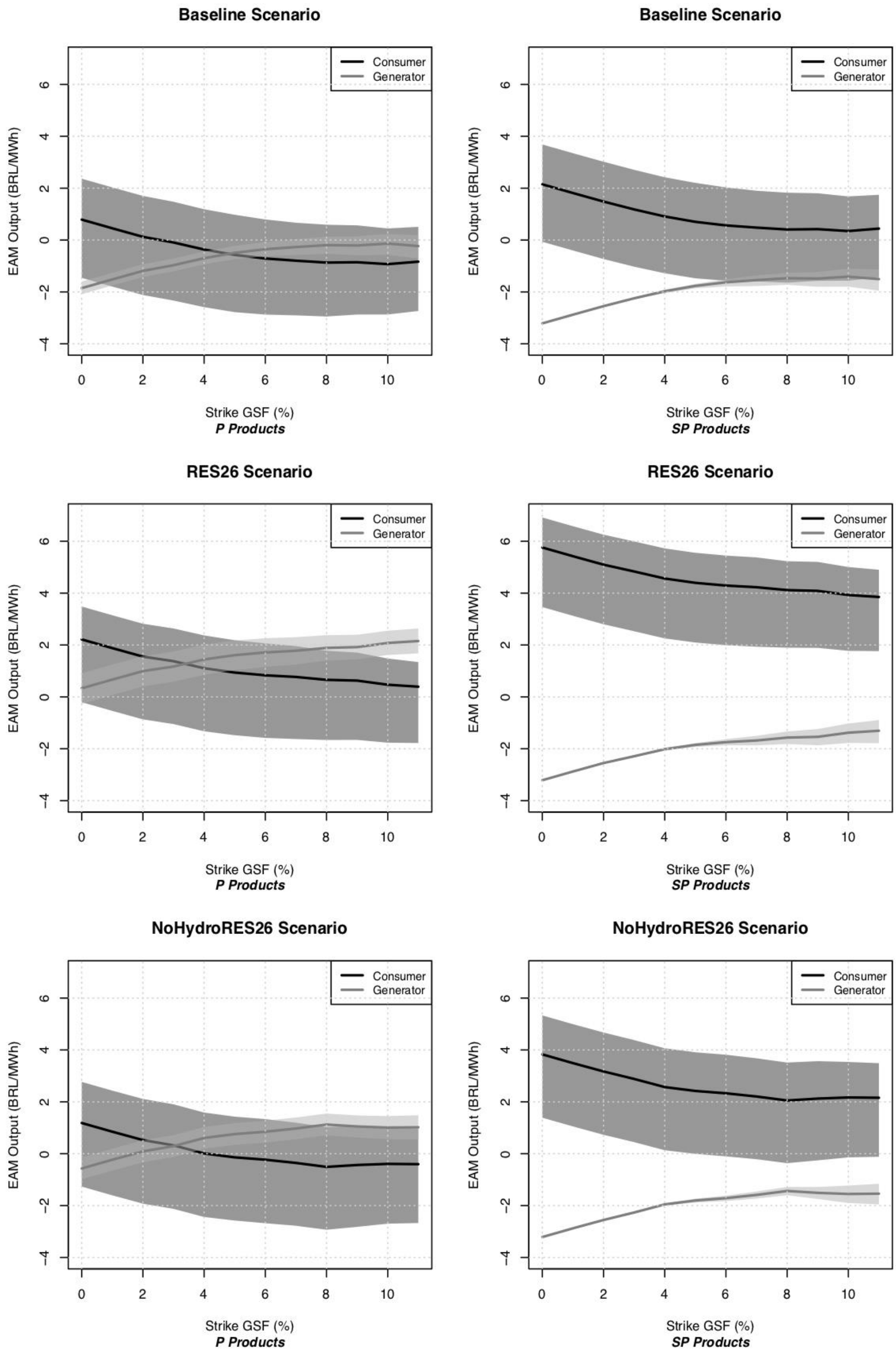


Table 3 - Baseline Scenario

Modality	Utility	Strike GSF (%)											
		0	1	2	3	4	5	6	7	8	9	10	11
P	Consumer	-1,46	-1,79	-2,12	-2,33	-2,59	-2,78	-2,87	-2,90	-2,95	-2,87	-2,87	-2,73
	Generator	-2,08	-1,75	-1,42	-1,21	-0,94	-0,74	-0,62	-0,58	-0,53	-0,59	-0,57	-0,71
	Market	-3,54	-3,54	-3,54	-3,54	-3,53	-3,52	-3,50	-3,48	-3,48	-3,46	-3,44	-3,44
SP	Consumer	-0,07	-0,40	-0,73	-1,03	-1,28	-1,48	-1,57	-1,60	-1,64	-1,57	-1,57	-1,44
	Generator	-3,21	-2,88	-2,56	-2,28	-2,05	-1,86	-1,79	-1,77	-1,73	-1,80	-1,80	-1,95
	Market	-3,28	-3,28	-3,29	-3,31	-3,33	-3,34	-3,36	-3,37	-3,37	-3,37	-3,37	-3,39

Table 4 - RES26 Scenario

Modality	Utility	Strike GSF (%)											
		0	1	2	3	4	5	6	7	8	9	10	11
P	Consumer	-0,20	-0,54	-0,87	-1,05	-1,33	-1,48	-1,58	-1,63	-1,66	-1,66	-1,77	-1,78
	Generator	-0,27	0,07	0,40	0,58	0,85	1,03	1,15	1,25	1,40	1,45	1,61	1,68
	Market	-0,47	-0,47	-0,47	-0,47	-0,48	-0,45	-0,43	-0,38	-0,26	-0,21	-0,16	-0,10
SP	Consumer	3,46	3,13	2,80	2,53	2,25	2,10	1,99	1,94	1,90	1,89	1,78	1,76
	Generator	-3,21	-2,88	-2,56	-2,33	-2,07	-1,93	-1,87	-1,87	-1,82	-1,87	-1,78	-1,78
	Market	0,25	0,25	0,24	0,20	0,18	0,17	0,12	0,07	0,08	0,02	0,00	-0,02

Table 5 - NoHydroRES26 Scenario

Modality	Utility	Strike GSF (%)											
		0	1	2	3	4	5	6	7	8	9	10	11
P	Consumer	-1,27	-1,60	-1,93	-2,13	-2,44	-2,58	-2,68	-2,78	-2,93	-2,82	-2,70	-2,67
	Generator	-0,99	-0,65	-0,33	-0,13	0,19	0,34	0,43	0,55	0,71	0,62	0,56	0,54
	Market	-2,26	-2,25	-2,26	-2,26	-2,25	-2,24	-2,25	-2,23	-2,22	-2,2	-2,14	-2,13
SP	Consumer	1,39	1,05	0,73	0,45	0,13	-0,01	-0,10	-0,21	-0,36	-0,26	-0,14	-0,12
	Generator	-3,21	-2,88	-2,56	-2,30	-2,00	-1,88	-1,82	-1,73	-1,60	-1,75	-1,90	-1,95
	Market	-1,82	-1,83	-1,83	-1,85	-1,87	-1,89	-1,92	-1,94	-1,96	-2,01	-2,04	-2,07

From the consumers' perspective, SP100 seems to be the most attractive option, regardless of mix scenario, risk aversion criterion (strike GSF) or product modality (P or SP). On the generator side, P products would be the preferable ones, no matter the scenario mix. Nonetheless, the strike GSF choice would be influenced by the mix expansion dynamics, since the best trade-off option is different among the mix options addressed here.

When checking CCEE data regarding ICO's settlements (CCEE, 2018b), most generators opted for the SP100 product, followed by SP92 and other types of SP products. There has been no procurement for P products. A first possible explanation for this is that hydropower developers may not apply a standard approach for assessing EAM's risk variability. Different methodological approaches lead to widely differing results, which may drive distinct final risk perceptions among hydropower stakeholders as well. The discussion here does not claim to be the only possible framework regarding EAM risk assessment and pricing.

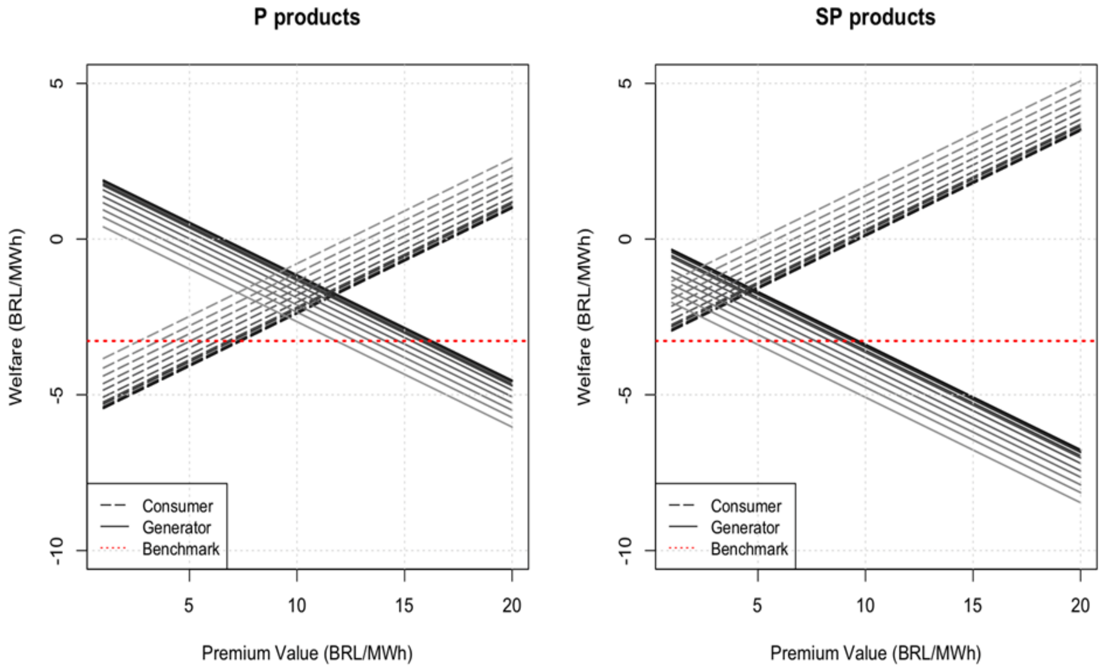
Furthermore, SP products have an important property of substantially reducing generators' cash flow volatility. This might be an attribute sought by market participants since within hydro asset's initial years there is usually the more intense cost of capital expenditure (both debt and equity), which might significantly enhance generator's propensity for call options that enable flat incomes. This could be reinforced if a decadal cyclical drought takes place, stressing the system's reliability and, consequently, hydro's cash flow.

5.2.1 ICO's sensitivity assessment

A sensitivity analysis was carried out to assess the performance of ICO allocation among a broader set of prices and strikes combinations. The results for baseline scenario are shown in Figure 15, where the domain for strikes GSF was kept the same, while the price varied from 1 to 20BRL/MWh. In this figure, grey degrees vary from darker (lower GSF strikes values) to lighter (higher GSF strikes). Benchmark represents the *status quo* market utility value (i.e. BRL3.28/MWh).

From Figure 15, we observe that for the same risk allocation share, economic utilities have a linear trend regarding premium values setting. So, if GSF strikes are fixed, consumers' utility rises with the increase of premium values. The opposite effect is observed for the generators. Moreover, due to the linear relationship between economic utility and premium values, the relative difference among them (market utility) stays the same, regardless of the premium value. Because of this parity, for instance, if a market-design were to maintain a 'null' result for the consumers, it would always lead to an outcome for generators below the benchmark reference, regardless the final premium value set. Hence, this would be an inadequate premise since it would make the insurance useless for generators.

Figure 15 – ICO's broad set of parameters combinations



On the other hand, if the premise were to annul generators' economic utility within the premium range considered, this could not be entirely achieved in the SP modality, since the cost driven by the premium payment could not be compensated by the revenue from surplus scenarios in EAM. In P modality, ensuring a null result for the generator would correspond to allocating results to consumers that are worse than the benchmark reference, which would also be an unprofitable design.

5.2.2 ICO's optimisation

The second sensitivity analysis carried out applied an alternative approach for setting premium values. It consisted of selecting the common point in Figure 15 where consumers' and generator's utilities matched each other, emulating a supply-demand equilibrium. The results are shown in Table 6, as well as its relative differences among ANEEL[16].

[16] In order to make this specific comparison fully suitable, another MC simulation where the cash flow period designated to be 25 years had been run.

Table 6 – Risk Premium Values and Relative Differences to ANEEL

Product Type	Optimal Risk Premium (BRL/MWh)	ANEEL's Risk Premium (BRL/MWh)	Relative Difference (%)
P100	11,94	12,75	-6,4
P99	11,93	11,75	1,5
P98	11,90	10,75	10,7
P97	11,78	10,00	17,8
P96	11,55	9,00	28,3
P95	11,38	8,25	37,9
P94	10,94	7,50	45,9
P93	10,30	6,75	52,6
P92	9,67	6,00	61,2
P91	8,98	5,50	63,3
P90	8,24	4,75	73,5
P89	7,33	4,25	72,5
SP100	4,98	9,50	-47,6
SP99	4,97	8,50	-41,5
SP98	4,92	7,50	-34,4
SP97	4,76	6,50	-26,8
SP96	4,48	5,50	-18,6
SP95	4,30	4,75	-9,5
SP94	3,79	4,00	-5,3
SP93	3,09	3,25	-4,9
SP92	2,48	2,50	-0,8
SP91	1,75	2,00	-12,5
SP90	0,99	1,25	-20,8
SP89	0,07	0,75	-90,7

The common ordered pair (premium value and economic utility) would thus yield individual positions where risk share and expected net returns would be the same. If these assumptions might be considered suitable, the results presented in Table 6 provide a conclusion that based on the model results from this paper, most ANEEL's P products should have their premium values enhanced (except P100), while SP premiums should be lowered.

5.3 Comparative Analysis

The comparative analysis between the two policy options relies strongly on the discussion presented in Section 4.5. In the baseline scenario, none of the ICO results would yield better economic revenues for consumers than the neutral position they had had within EAM *status quo*. As may be observed in Table 3, all consumers' utilities are negative (worse than null), regardless of mix scenario or product's modality or type.

Meanwhile, consumers would have their positions improved if any of SP modality takes part in RES26 scenario (see Table 4), while generators would not have any incentive to procure them, as they would not yield better economic utilities than the ones originally pushed by EAM *status quo* directives. In NohydroRES26 perspective, SP100 to SP96 would provide a better result for consumers, while the most suitable options would still be available for generators.

Nevertheless, the analysis carried out in the previous section suggests that ICO design may lead to an overall improvement in the system level welfare compared to the *status-quo* EAM if a criterion of equivalent welfares is set as an ICO priority design goal. Because EAM *status quo* has higher hedge costs, ICO design could push a compromise solution where individual welfare decrease would possibly yield a better market equilibrium, benefiting both consumers and generators.

It is also observed that ICO yields higher market economic utilities when compared to the same hypothesis in EAM *status quo*. This is because ICO's conceptual framework establishes a new money entrance within the EAM operation, whereas the overall amount of energy transacted in the hydro pool remains the same. Thus, if the total ratio between financial and energetic resources rises, and the GSF average index tends to be a negative value (i.e. Baseline and NoHydroRES26), the adverse global result increases as well. On the other hand, if the long-term economic indicator for EAM is positive (i.e. in RES26 scenario), ICO would drive a higher overall market indicator than the *status quo* policy.

6. Conclusions and Policy Implications

In this research, two policy approaches for designing risk share among hydropower operations in Brazil were assessed. The system's expansion criteria and dynamics may influence EAM performance and thus hydropower economic feasibility. For instance, EAM is likely to be an unprofitable mechanism for hydro-generators within the current mix configuration since its thermal portfolio has a relatively great share of base-load units, thus competing with hydropower for the preference of the dispatch. Conversely, it may become feasible only by modifying thermal base-load and peak-load expansion parameters. The thermal economic and physical characteristics are the main features that impact EAM performance.

On average, the participation of RES does not have a significant bearing on EAM results in the long-run. Indeed hydropower would be positively impacted in a scenario with more dependence on non-controllable resources (RES or run-of-river hydro) than when reliant on base-load thermal generation. This is valid when RES growth is always fully met by the same increment in the system's load, thus not significantly modifying the system's controllable merit order that is dynamically constituted between the hydropower reservoirs and the thermal portfolio.

It can also be concluded that the current ICO approach drives a significant transfer of wealth from consumers to generators and does not yield perfect monotonic behaviours within GSF's strike range, indicating scope for its improvement. From the consumers' perspective, SP100 seems to be the least bad option, regardless of mix scenario, risk aversion criterion (strike GSF) or product modality (P or SP). On the generator side, P products would be the preferable ones, no matter the scenario mix.

Conversely, ICO design may lead to an overall improvement in the system level welfare compared to the *status-quo* EAM, if a criterion of equivalent welfares (i.e. same expected results for both generators and consumers) is set as an ICO design goal. Because EAM *status quo* has higher hedge costs, ICO design could lead to a compromise solution where individual welfare decreases would possibly yield a better market arrangement, benefiting both consumer and generators in the end.

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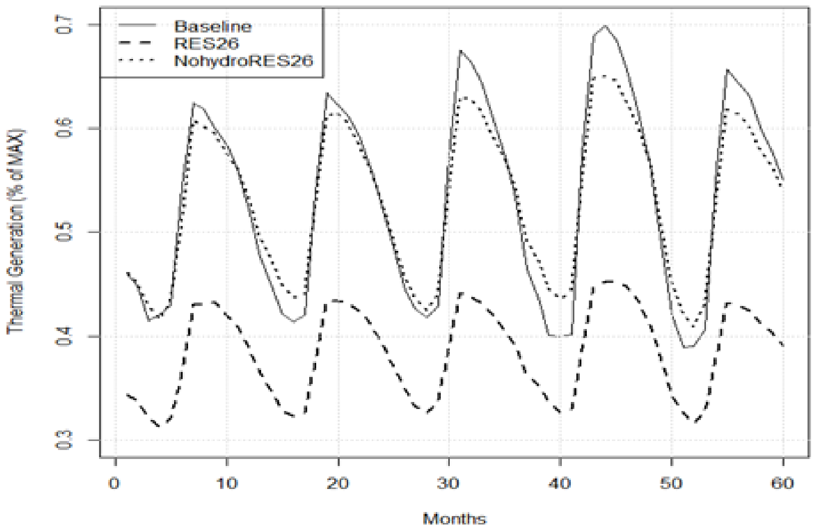
Annexe

Table 7 – Indicative Hydro Plants of the Expansion Plan (EPE, 2017a)

NAME	SIZE (MW)	START-UP YEAR
Telêmaco Borba	118	2023
Tabajara	350	2024
Apertados	139	2025
Ercilândia	87	2025
Foz do Piquiri	93	2025
Castanheira	140	2026
Porto Galeano	81	2026
Bem Querer	709	2026
Itapiranga	725	2026

Figure 16 – Thermal Average Generation

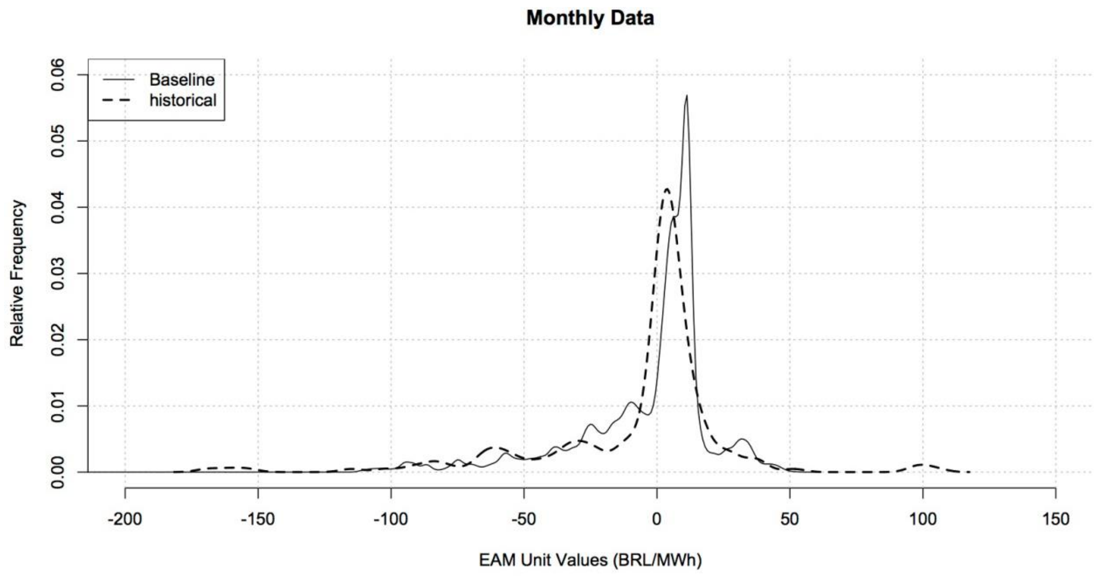


Model Reliability

The model's stochastic outputs may not be very distinct from the empirical probability function released by the operational record. Hence, the EAM unitary value densities were compared, while historical data was gathered from 2001 until 2017 (CCEE, 2018a). This approach was essentially coupling GSF indexes and correspondent's spot prices accordingly to Equation 11[17]. In Figure 17 both curves are shown.

[17] The marginal operational costs from Newave were taken as reasonable proxies for the market's spot prices. Yet the spot prices in Brazil are weekly based and are calculated within a coupling-in-time procedure where the long-term optimal policy provided by Newave is read and desegregated by another SDDP modeling algorithm (Decomp model). Decomp yields weekly optimal dispatch targets for each plant and the correspondent marginal costs for each of the four markets that compose the national system. To convert the weekly spot prices record into a monthly base, a load-weighted-average approach accordingly to each market relative share was done.

Figure 17 – Static Simulation Calibration



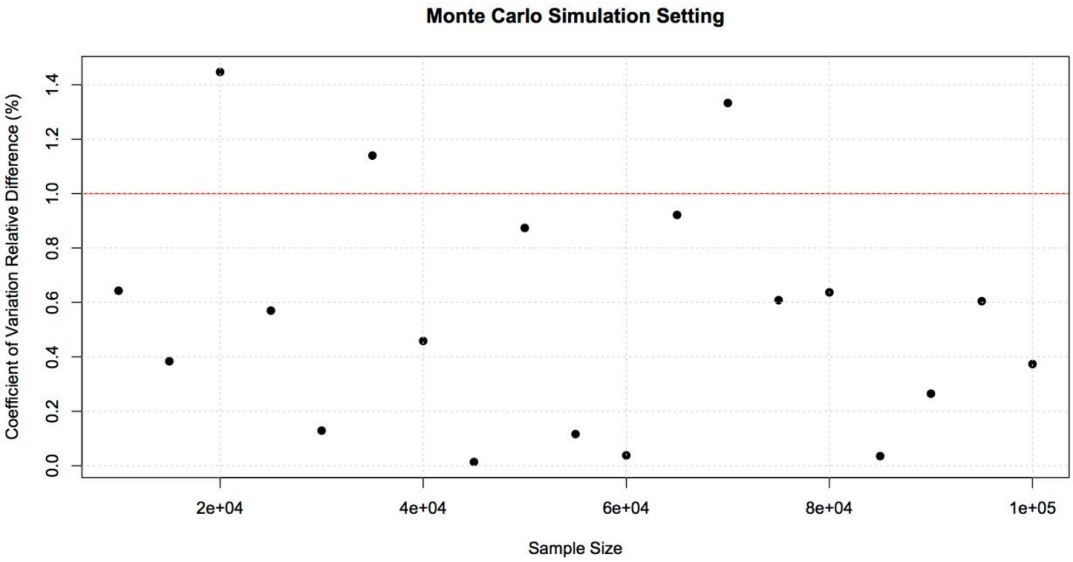
When looking at the two curves, one may realise that baseline scenario ranges and probabilities are close to the same ones from the historical record. Indeed, as mentioned in section 3, static simulations are designed to provide the system's reliability assessment. So if the system has been so far planned and operated steady, a static simulation approach could not be very far from its historical record. The compromise conditions regarding FEC's loop convergence (see Figure 3) are presented in Table 8.

Table 8 - Compromise conditions for FEC's convergence

Scenario	Critical Load (MWavg)	Average MOC (BRL/MWh)	Average Shortages (%)
Baseline	84.410	192,61	0,21
RES26	99.112	191,24	0,37
NoHydroRES26	97.827	191,45	0,29

Another relevant aspect was setting the sample size within the MC simulation. The number settled was 80.000, based on the results shown in Figure 18, where a difference for the coefficient of variation less than 1% was established as a target goal (red line).

Figure 18 – Monte Carlo Setting



Author contacts:

Bruno Goulart F. Machado (corresponding author)

Brazilian Electricity Regulatory Agency

SGAN 603 módulos I e J,

Brasília – DF,

Brazil

Email: brunogoulart@aneel.gov.br

Pradyumna Bhagwat

Florence School of Regulation, Robert Schuman Centre for Advanced Studies, EUI

Via Boccaccio 121

I-50133 Florence

Italy

Email: Pradyumna.Bhagwat@eui.eu