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A comprehensive analysis of the Demand Response Program proposed in Brazil based on the Tariff Flags mechanism

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ABSTRACT

The Brazilian Electricity Regulatory Agency (ANEEL) presented a proposal to revise the tariff structure of distribution companies in Brazil. One of the main approved suggestions was to establish a mechanism called Tariff Flags, which aims to foster a Demand Response Program in Brazil via an increase in the energy tariff.

In this work, the proposed mechanism is reviewed in detail and the expected results of its application are simulated and analyzed under different perspectives. This paper shows that the system operation directly impacts the Demand Response Program, since the spot prices will define which Tariff Flag should be triggered. In order to encompass and assess the main consequences of its application, this paper presents the expected effects on energy spot prices, system operating costs, probability of triggering each flag, investment recovery for utilities and finally, the impact for the final consumers. The case studies presented in this paper were developed using real information about the Brazilian electrical system for each economic sector and the price-demand elasticity is discussed using the literature for this application. Finally, some conclusions and guidelines are provided to improve the application of the mechanism.

1. Introduction

Energy tariffs are the unitary cost of energy, which represents the energy price that consumers will be charged by utility distribution companies for the energy consumed. The challenge of designing Bulk Supply Tariffs (BSTs) consists of creating a model that sets different prices for consumers to influence their energy consumption pattern. This approach, ultimately, would (i) improve the grid utilization, (ii) reduce the operating costs and (iii) postpone investments in generation and transmission capacity. To achieve this goal, a Demand Response Program (DRP) can be applied.

The Brazilian DRP was implemented in early 2015. The new program, called Tariff Flags, is coming to fulfill an old requirement of the electricity sector, since the current rules has not been updated for quite some time and the captive market was blind to the current power generation costs. In this sense, the objective of this paper is to analyze in details the effect of Tariff Flags on the entire system and its economic effect on distribution companies and consumers, taking into account the price elasticity of demand (PED) of the consumers.

The system regulator can apply the DRP to curtail or shift loads instead of building more generation and/or transmission lines. According to Refs. [1,2], the DRP can be implemented in two different ways, the first based on an incentive mechanism and the second based on a price mechanism.

The incentive-based mechanism can be made through the Direct Load Control (DLC), Interruptible Curtailable Service (ICS), Emergency Demand Response Program (EDRP), Demand-Side Bidding (DSB), Capacity Market Programs (CAP) and/or Ancillary Services Market Programs (ASMP).

The DLC is a service usually offered to residential customers in which the system operator remotely shuts down or cycles a consumer's electrical equipment (e.g., air conditioner, water heater, etc.) to reduce the consumption during certain time of day or the peak demand time. To encourage the costumers to reduce their consumption, a tariff discount or a bill credit is offered. A similar incentive is applied through the ICS for larger customers (industrial or commercial) who agree to reduce their consumption during system contingencies.

Through the EDRP application, the distribution company pays eligible business customers to temporarily cut back energy use during power shortages or other emergencies. Through the DSB mechanism, the customers offer bids to curtail their loads to the distribution company based on wholesale electricity market prices. A bid will be accepted if its value is smaller than the market price.

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When the bid is accepted, the customer must curtail the load by the amount specified in the bid, or penalties will be faced. This program is usually offered to large customers.

According to Ref. [2], in the CAP, customers commit to pre-specified load reductions when system contingencies arise and are subject to penalties if they do not curtail their use when requested. This mechanism can be seen as a form of insurance. Finally, in the ASMP, the customers bid load curtailments to the ISO (Independent System Operator) as operating reserves. If their bids are accepted, they receive to the market price for committing themselves to be on standby, i.e., if load curtailments are required, they are called by the ISO and will be paid based on the spot energy market price.

Price-based mechanisms can also be an alternative for promoting the consumption optimization of the demand. The price-based mechanism uses the tariff system to incentivize the customers to change their consumption pattern to improve utilization of the system resources. Although it takes time to recruit customers for a DRP, a well-structured pricing and incentive-based DRP can produce significant savings close to real time, often at lower costs than supply-side resources [1]. According to Refs. [3,2], the DRP based on a Price-Based Program (PBP) may present different approaches: Time of Use (TOU) [4], Critical Peak Price (CPP) [5] and Real Time Pricing (RTP) [6].

The TOU mechanism defines the energy price ex-ante for each period. The period can be hours (peak and off-peak) in a day, days in a month (weekdays and weekend) or even different seasons in a year. The CPP scheme establishes that during a critical period, usually related to extreme weather conditions, a higher price is set for consumers. Finally, the RTP mechanism defines that the tariff should reflect the real-time system conditions, i.e., the economic signals provided to the market should consider the balance between supply and demand for each time period.

The DRP has been explored in other publications. In Ref. [7], a DRP is analyzed considering the impact of an Advanced Metering Infrastructure to encourage consumers to reduce their consumption on peak hours. In Ref. [8] the authors presented how to incorporate the benefits of distributed Photovoltaics in the tariff of residential customers in California. The results were compared to the tariff applied by the distribution company. The Time-of-Use (TOU) tariff was studied in Ref. [9] in the context of high penetration of Electric Vehicles. The authors presented recommendations in terms of policy and regulations as well as the TOU mechanism and smart meter deployment. In Ref. [10] the authors addressed the impact of Renewable Energy Penetration in DRP. To accommodate the renewable energy intermittency, they proposed: (i) a change in the regulatory framework of the electricity market in order to enhance the DRP; and (ii) the use of AMI systems. In Ref. [11], a DRP was analyzed in the non-domestic sector of UK. According to the authors, these analyses pointed that the demand response measures tend to incentivize stand-by generation capacity rather than load shifting. Additionally, in Ref. [12], a review of DRP costs and benefits is presented for the electricity market of UK, pointing out the benefits of the program. A perception of the residential costumer was studied in Ref. [13] and their findings showed that the households as a whole have a fairly high opinion about the demand-based tariff and react based on the energy price change by decreasing their peak demand and shifting electricity use from peak to off-peak period.

In this paper, a new mechanism called Tariff Flags is analyzed and explained in detail. The mechanism has been proposed in Brazil and started to be implemented in 2015. The objective of this paper is to analyze the effect of Tariff Flags on the entire system and its economic effect on distribution companies and consumers, taking into account the utilities' contract portfolio and the price elasticity of demand (PED) of the consumers. The paper is organized as follows: Section 2 presents the Tariff Flag mechanism proposed in Brazil and the assumptions considered to simulate the Tariff Flags' impact. Section 3 presents the discussion of these simulations and the results. Finally, conclusions and recommendations for DRP improvements are presented in Section 4.

Table 1
Brazilian electricity matrix [29].

	2014		2023	
	MW	%	MW	%
Renewable sources	110,335	83.20%	164,135	83.80%
Hydro	88,661	66.90%	116,894	59.70%
Wind	5452	4.10%	22,438	11.50%
Others (Small Hydro, Biomass and Solar)	16,222	12.20%	24,082	12.30%
Conventional sources	22,224	16.80%	31,748	16.20%
Total	132,559	100%	195,883	100%

2. Methods

Brazil has large and varied energy resources, particularly hydro, which represents a 67% of the installed capacity and the remainder part coming from thermal plants and others. Table 1 summarizes the aforementioned:

As the Brazilian system is basically hydrothermal and the short-term operation is centrally coordinated by Independent System Operator, the minimal cost dispatch model is used to define the generation of Hydro and conventional sources. The other sources (Small Hydro, Biomass and Solar) are not centrally dispatched. A byproduct of this model is the operational marginal cost, which defines the Energy Spot Price. As it can be seen in the results, the Energy Spot Price defines the triggering of the Tariff Flags and, as a conclusion, the renewable energy plays an important role in the application of the DRP.

Currently, a different pricing mechanism has been applied for high voltage consumers, i.e., those that are connected at 2.3 kV or higher. The mechanism is based on the TOU, and it is known as the Hour-Seasonal Tariff. It was established in the late 1980s. The energy tariff, defined to be used either in the dry season (from May to November) or in the wet season (from December to April) was designed based on simulation studies of the Brazilian Electricity System and takes into account the effect of the demand increase on the short run marginal costs (*CMO*) for each month of the year.

The average *CMO* for these two seasons resulted in a fixed tariff rate for dry and wet seasons used until today, where current dry season tariffs are 12% more expensive than the wet season tariffs. Because hydroelectric power plants supply mostly the Brazilian Electricity System, this value (12%) represents the expectation of the water usage benefits to generate electricity.

A public hearing (#120/2010) [14] proposed by *ANEEL* was held to analyze the *CMO* historical behavior since May 2003 and to assess if there was a relationship between it and the tariff signal introduced by the fixed rate within the different seasons of the year. *ANEEL* concluded: "The *CMO* does not show a standard pattern in dry and wet seasons. Consequently, the tariff signal applied today does not represent the expectation of the water usage benefits flagged by the *CMO* price."

ANEEL argues that the contracts between distribution companies and generators do not have different prices for the aforementioned seasons because the price of the energy contract was set in an auction.[1] Furthermore, although the energy tariff for

[1] In Brazil, the energy contracts between generators and utilities are settled by auctions. The type of energy contract is defined before the auction, and it can be in quantity, in which the delivery energy obligation is of the generator, or availability,

consumers can change only once a year, the energy costs for distribution companies may vary on a monthly basis, depending on the type of contract, as follows:

i The operating cost reimbursements of thermoelectric power plants contracted by availability when triggered by the National System Operator (*ONS*) as part of the system's operational optimization or, in a compulsory way, the energy purchase in the spot market when these plants are not triggered;
ii The operating costs due to additional out of merit thermal dispatch determined by *ONS*, in order to maintain the system's security of supply. In this case, this additional dispatch does not form the spot market price and its respective costs are incorporated in the System Service Charge for Energetic Security (ESS_{SE}) and transferred for all consumers via energy tariff.

To minimize the problem, *ANEEL* proposed the consideration of a forecast of these variable costs 12 months ahead of each annual tariff readjustment. However, the supplemental operating actions of the economic dispatch concerning the energetic security measures taken by *ONS* have led to significant discrepancies between forecast and real costs. As a result, *ANEEL* concluded that if the consumers had a short-term signal to react to the energy cost variation (due to the thermal plant dispatches), they could help the national energy policy by reducing energy consumption when prices are higher. The mechanism proposed to face this problem is called Tariff Flags, explained in detail in the next subsection.

Another important regulatory change is the new method of adopting a risk-averse approach in the system's optimal operating policy determined by Resolution CNPE n° 03/2013 [15]. As a consequence of this change, the future *CMO* expected values have risen, directly affecting the availability contract costs. Preliminary simulations performed by the permanent commission of the electricity sector for methodology assessment and computational models showed that the risk-averse implementation provoked an increase between 50 R$/MWh and 150 R$/MWh in *CMO*, compared to the results obtained with the former risk-neutral approach. An impact analysis of the Tariff Flag mechanism in the long-term electric-energetic system operation with a risk-neutral approach can be found in Ref. [16].

2.1. Tariff Flags

Taking the aforementioned arguments into account, in the public hearing (#120/2010), *ANEEL* proposed and, consequently, approved the exchange of the hour-seasonal energy tariff for a monthly variable economic signal called Tariff Flags. The Tariff Flags are Green, Yellow and Red, and they consist of a short-term economic signal that acts as a traffic light and will represent tariff differences to the consumer. As introduced in the previous section, this mechanism seeks to apply to the captive market as an incentive that reflects the current power generation costs by means of a short-term economic signal. It aims to minimize eventual differences between costs and revenues of the utilities and contribute to the optimization of the system's electricity and energy resources. The target consists of all captive consumers[2] of the Brazilian National System (high and low voltage).

The Green Flag occurs when generation costs reflect the contract costs already priced. The Yellow Flag indicates a warning signal that the water value reflected in the *CMO* is rising or that thermal power plants are being dispatched. Finally, the Red Flag indicates that the previous situation is getting worse, and the balance between supply and demand occurs with higher generation costs. Accordingly, the monthly signal is based on the *CMO* (in R$/MWh[3]).

Table 2
Tariff Flags and operating ranges.[a]

Tariff Flags	Range {CMO} (R$/MWh)	Economic signal (R$/MWh)
Green	<200	–
Yellow	≥200 to <350	15
Red	≥350	30

[a] Due to the changes in the system's optimal operating policy promoted by Resolution CNPE n° 03/2013, a second phase of a public hearing (#104/2012) has been opened to improve the regulatory aspects of the Tariff Flag application. Taking the abovementioned impact of the risk-averse approach into account, a revision on the Tariff Flags range has been proposed. Three different categories, as presented in Table 1, were defined to classify the Tariff Flags and to assign the customers the final energy price.

According to Tariff Flags rules, the Tariff Flag is kept green if the proxy (*CMO*) is smaller than 200 R$/MWh, which means that the energy tariff did not change. If the energy price is between 200 R$/MWh and 350 R$/MWh, the Yellow flag is triggered and the tariff will be raised by 15 R$/MWh. Finally, if the energy price is higher than 350 R$/MWh, the Red flag is triggered and the energy tariff increment will be 30 R$/MWh. Table 2 summarizes the aforementioned criteria.

The increment on the energy tariff associated with the Tariff Flags has been defined as a unique value for all distribution companies. However, when the corresponding effect of each utility is evaluated, it can be seen that the increment should be higher than 15 R$/MWh and 30 R$/MWh for most of them. This occurs because the increment is determined based on the average of the total cost passed on to utilities, which includes *CMO* associated costs. However, distribution companies in Brazil have different types of contracts in their portfolio. As a result, some of them would have extra cash flow from the Tariff Flags that would not cover their costs, and others would have an extra cash flow that exceeded their needs, which creates a cross-subsidy among them. To illustrate this, Fig. 1 presents the estimated increments for some of the distribution companies in Brazil, taking their portfolio into account.

As seen, some utilities, such as ENERGISA-MG, with 6% availability contracts, are less susceptible to energy price changes. They would have an extra cash flow when the Yellow (15 R$/MWh) or Red Flag (30 R$/MWh) are triggered, without presenting compatible cost increments. In this case, the Tariff Flags' associated increments for ENERGISA-MG should be approximately 6 R$/MWh for the Yellow Flag and 12 R$/MWh for the Red Flag. Other distribution companies, such as COSERN, with 27% of availability contracts, would not have enough revenue to compensate for their increased costs, i.e., the associated increments would be approximately 30 R$/MWh for the Yellow Flag and 55 R$/MWh for the Red Flag to achieve this goal.

The Tariff Flag mechanism has been implemented on an experimental basis in 2014 without charging the consumers but informing them which flag would be triggered if the mechanism were being applied. Considering the distortion of the availability contracts of the distribution companies, it should be improved to be properly applied.

in which the distribution company pays a "rent" for the generator and assumes the financial responsibility of the energy generation.

[2] Captive consumers are consumers who have an energy contract with the distribution company. They pay their energy consumption by a regulated tariff.

[3] R$ 1 ∼ US$ 0.308.

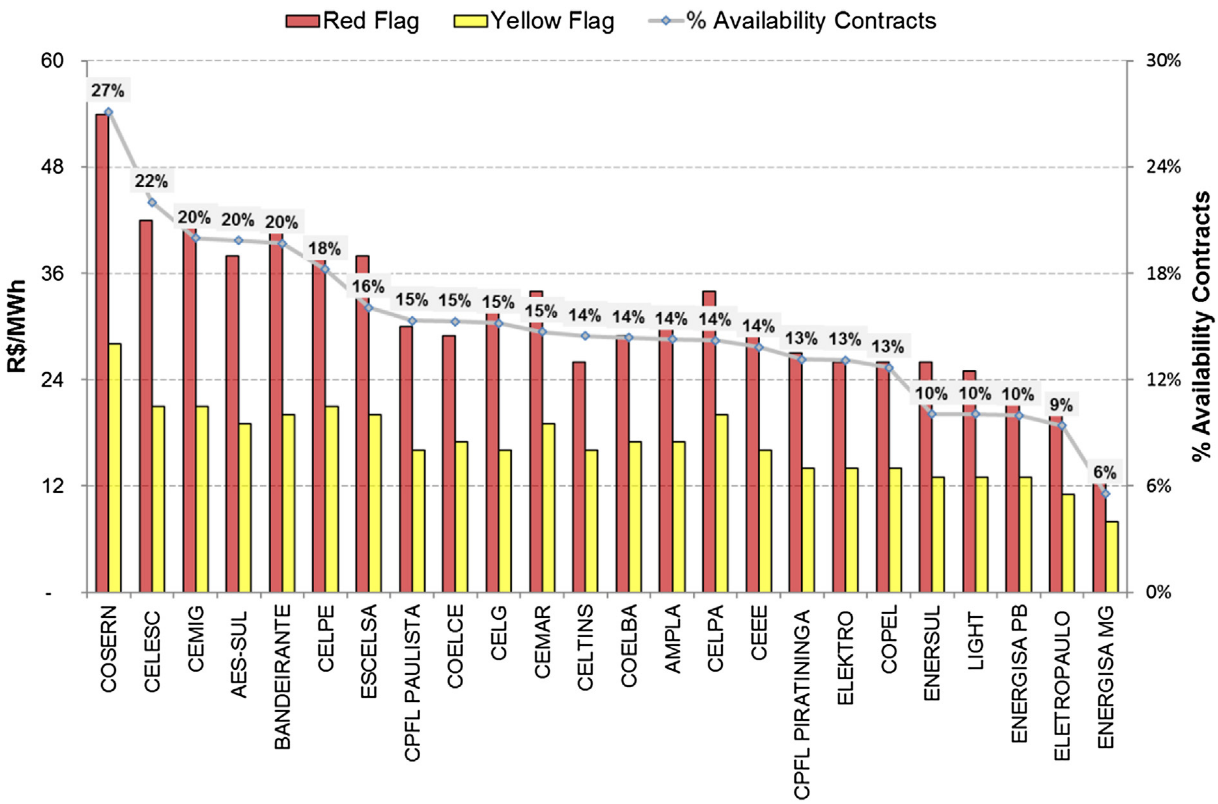

Fig. 1. Individual increments for each distribution company considering portfolio differences.

2.2. Assumptions to simulate the Tariff Flag effects on the long-term system operation

Because Tariff Flags represent a traffic light for the consumer, directly reflecting generation costs through tariff increases, it is consequently expected to represent changes in the total operating costs of the system. Accordingly, to assess the impact of the Tariff Flags, the *CMO* should be calculated for each month of the time horizon under analysis through a long-term hydrothermal dispatch simulation of the Brazilian National Interconnected System. This step is based on the simulation of the Brazilian system's optimal operating policy for a given energy supply and demand scenario using the hydrothermal dispatch model, which will be described in Subsection 2.6.

To measure the effect of the Tariff Flags on the consumers, it is first necessary to model the load behavior compared to the electricity price signals. The model of electricity customers' response to price should consider several factors, such as habits, load type and consumption profiles. However, the main factor is the price variation; this is measured by the consumer-price elasticity, which is different for each economic sector and in each submarket.[4] In other words, each economic sector in each submarket has its own elasticity. To identify the DRP effect on the different sectors in all submarkets, Subsection 2.3 presents the different sectors in each Brazilian submarket; Subsection 2.4 presents the elasticity price-demand values for each sector, as well as the references; finally, in Subsection 2.5, the expected reduction in energy consumption of each economic sector is assessed to estimate the effect of the Tariff Flag mechanism application.

[4] Submarkets are geo-electric areas with different *CMO* values due to the limited power transfer capacity between them.

2.3. Submarket***'s demand segregation***

Because Tariff Flags will be applied for all captive consumers, the first step is to break down the consumer behavior of each submarket into economic sectors: residential, commercial and industrial which are elastic to a change in price, and free consumers, low income and other sectors, which are (inelastic). To accomplish this task, it is necessary to know the percentage of participation of each sector in the submarket's total demand. All of these percentages, shown in Table 3, are based on Brazilian market data available in Refs. [17,18]. As seen, the most representative elastic portions are mainly located in the South and Southeast/Central-West submarkets.

2.4. Price elasticity of demand: definition and presentation

After breaking down the demand to define which portion is elastic to price variations, the next step consists of quantifying the consumers' response. The measure that indicates the demand responsiveness due to price variations is the price elasticity of demand (PED). The PED can be expressed as follows:

$$\varepsilon_{Q,P} = \frac{\partial Q/Q}{\partial P/P} = \frac{\partial Q}{\partial P} \cdot \frac{P}{Q} \tag{1}$$

where Q is the demanded amount, and P is the price of the good. The term $\partial Q/\partial P$ states that an infinitesimal change in the price implies in an infinitesimal change in the demand for the good being analyzed. The aforementioned formula usually yields a negative value due to the inverse relationship between price and demanded amount, as stated by the "law of demand." Briefly, an increase in the price will result in a reduction in the demanded amount, and vice-versa.

This paper's literature review aimed to find sources in which the analyzed profile was adequate for the purpose of the study. In Ref.

Table 3
Elastic and inelastic portions of the demand in each submarket.

Submarket	% of participation in each submarket					
	Inelastic portion			Elastic portion		
	Free consumers	Low income consumers	Others	Residential	Industrial	Commercial
North	42.13%	6.13%	11.60%	14.89%	12.85%	12.40%
Northeast	19.48%	12.05%	19.26%	19.91%	16.55%	12.75%
South	20.76%	2.59%	14.30%	21.66%	17.27%	23.42%
Southeast/Central-West	20.86%	1.93%	13.64%	36.18%	9.33%	18.06%

Table 4
Price elasticity of demand of three economic sectors [19].

Sectors	Price elasticity of demand
Residential	−0.146
Industrial	−0.545
Commercial	−0.174

[19] the PED was evaluated to estimate energy consumption for residential, industrial and commercial sectors from 2000 to 2005. In this work, the calculation of the price elasticity of demand used annual data (tariff and consumption) from 1969 to 1999 of each economic sector. Table 4 summarizes the results obtained through the literature review.

Due to the lack of specific available data in the literature, a PED for a good in general was considered. The results presented in Table 4 can be interpreted as follows: each percentage point increase in the energy tariff, for example, in the residential sector leads to a reduction of 0.146% of its consumption. In addition, it is clear that the most responsive sector to price signals is the industrial sector, whose response to a percentage change in price is about four times greater than is observed in the residential sector. Finally, the PED for the commercial sector is similar to the residential sector.

2.5. Price elasticity of demand: curves

Considering the demand breakdown and the PED respectively presented in Subsections 2.3 and 2.5, the demand of each submarket will be divided into four categories: residential, commercial, industrial and "others." This is done to take into account the demand response in the long-term electric-energetic system operation.

To illustrate the demand modeling, Fig. 2a shows the demand response to a change in price when the inelastic portion is considered, and Fig. 2b presents the load behavior with the price variation associated with the elastic portion. It can be seen that this curve is comprised of three segments, the first being inelastic and the other two elastic.

The component "others" will be considered inelastic, which means that their behavior does not change with price variation, as shown in Fig. 2a. The residential, commercial and industrial sectors will be modeled according to Fig. 2b, i.e., the demand response of the Tariff Flag mechanism.

As seen, from 0 to 200 R$/MWh, there is no consumer response. If the *CMO* reaches 200 R$/MWh, the Yellow Flag will be triggered, and, as a result, 100% of the demand is considered in the system simulations. If the *CMO* is higher than 200 R$/MWh and smaller than 350 R$/MWh, there will be a demand reduction of x%. This percentage (x%) is defined according to the PED from each economic sector described in the previous subsection. Finally, if the *CMO* reaches 350 R$/MWh, the economic signal imposed on the customers' tariff will be even higher due to the Red Flag trigger, which will consequently cause a demand reduction in the elastic portion. Therefore, after reaching this point, the demand will be reduced by y%, and this percentage is also defined by the elasticity. It is worth mentioning that because there is no other increment in price after the Red Flag has been triggered, the demand is no longer responsive to price anymore, and this segment will be inelastic, i.e., its supply interruption is only associated to a physical unavailability of the system to meet it.

To evaluate the demand percentage of reduction associated with the Yellow and Red Flags' application, i.e., the x% and y% values present in Fig. 2b, it is necessary to know the current energy tariff increases (also in percentages) when the 15 R$/MWh and 30 R$/MWh increments are applied.

In summary, taking the tariff increases due to the application of the Tariff Flag mechanism and the price elasticity of the demand associated to each economic sector into account, the demand curves were created. Finally, the optimization process of the system operation takes into account the demand response to price and seeks the balance between supply and demand. These issues will be thoroughly discussed in Subsection 3.6.

2.6. Operative simulations

Taking all aforementioned assumptions into account, two simulations were performed to evaluate the impact of the Tariff Flag mechanism application in the system's operation. As in 2014 the mechanism was applied on an experimental basis, the simulations were performed starting in 2014. The first one, named "Case 1—Inelastic Case", represents the Monthly Operation Program (*PMO*) released by *ONS* over the time horizon until late 2017. This simulation considers the demand of each submarket as totally inelastic, i.e., there is no demand response to a change in price. The second one, named "Case 2—Elastic Case", represents the demand divided by economic sectors with the PED curves defined in the previous subsection. The model used to perform these simulations of the Brazilian long-term hydrothermal operation is called SDDP®.[5]

The first step of these simulations is to calculate the system's optimal operating policy for the given energy supply and demand scenario using the aforementioned hydrothermal dispatch model. With the stochastic operating policy, two simulations of the system's operation are performed for a sample of 1200 hydrological series with statistical analyses (hydrological scenarios) in each case: The first one is called physical simulation, which evaluates the system's operating policy to obtain the Future Cost Function (*FCF*) and the hydro storage trajectories of the system; the second one is called commercial simulation, which simulates the system operation based on the *FCF* and storage trajectories from the previous item to produce the *CMO*, which, as stated before, represents the water value in each time stage.

These simulations provide numerous results, but most notably related to the (i) thermal dispatch projection for each thermal plant,

[5] SDDP (Stochastic Dual Dynamic Programming) is a commercial simulation tool developed by PSR that is capable of calculating the minimum cost stochastic operating policy of a hydrothermal system considering operating details of the power plants and transmission system as well as constraints on natural gas supply and stochastic hydrology inflows.

Fig. 2. (a) Inelastic curve. (b) Elastic curve.

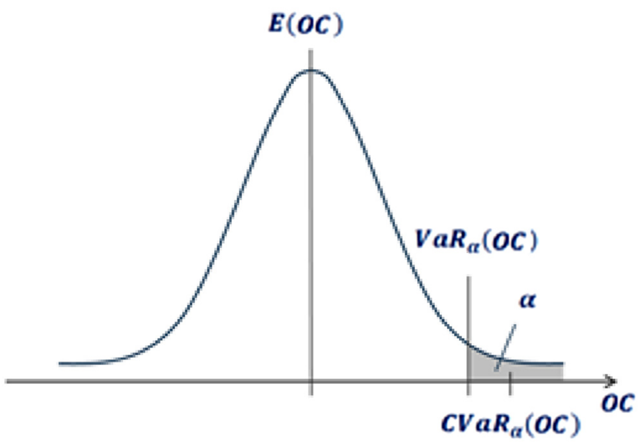

Fig. 3. Operating cost probability density function.

(ii) operation marginal cost projections, (iii) spot prices, (iv) deficit risks and (v) the demand response to price variations.

2.7. Risk-averse approach

The Resolution CNPE n° 03/2013 defined the incorporation of the risk-averse methodology into the operation planning model. The main objective of this methodological change is to guarantee that the system security will be determined by the optimal policy and no longer by supplementary actions, as it was in the past through ESS_{SE}. In this sense, a reduction in or even the absence of supplementary generation is expected.

Traditionally, the optimal operating policy leads to the minimum expected cost for the consumer. This methodological change suggests choosing as optimal decision the decision that minimizes the weighted sum of the expected system operating cost and an extreme value (associated with the distribution tail), with the aim of giving greater weight to unfavorable flow scenarios in the decision-making process. Thus, a change in the objective function of the operation planning problem was proposed to minimize a convex combination of the expected system operating cost and its *CVaR* (*Conditional Value at Risk*), as described in the equation below:

$$Min\,[(1-\lambda) * E(OC) + \lambda * CVaR_{\alpha}(OC)] \quad (2)$$

where λ is the "risk-averse factor" defined by the system operator, which represents the relative weight between the average and the extreme values in the objective function. The term $E(OC)$ is the expected value of the operating cost (OC). The term $CVaR_{\alpha}(OC)$ is the average of the α% worst operating costs, where α is the "confidence level," a parameter that is also defined by the operator.

To illustrate the concept of the *CVaR*, Fig. 3 presents an example of the operating cost probability density function:

Based on the figure, it can be seen that the *VaR* (*Value at Risk*) is the operating cost associated with quantile α, and $CVaR_{\alpha}$ is the average of the cases worse than or equal to the *VaR*. Through the analysis of the objective function, it is possible to see that the greater the risk-averse factor, the greater is the weight associated with adverse situations, consequently the preventive thermal dispatch will be greater. By increasing thermal generation levels, this approach contributes to an increase in the security of supply and will indirectly represent an increase in the *CMO* price. It is worth mentioning that this methodology is called *CVaR*-cost.

By calculating the system operating policy using this methodology, more importance is given to severe hydrological scenarios, which are a quite intuitive way of representing the risk-averse concept. The parameters chosen by the government are $\lambda = 0.25$ and $\alpha = 50\%$ [20]. More details about the insertion of the risk-averse approach in the system operating policy based on the *CVaR*-cost methodology can be found in Refs. [20,21,23–28].

3. Results and discussions

To analyze the DRP applied in Brazil, the following effects of the Tariff Flag mechanism implementation were chosen: (i) the total demand reduction, which indicates whether the DRP would be successful in considering demand reduction during *CMO* peaks; (ii) changes in the *PLD*[6] change of each submarket, which represents the effect of the Tariff Flag application in the (iii) the total system operating cost, which tends to be lower as a result of the Tariff Flag application, (iv) the probability of triggering the Tariff Flags, which gives quantitative information about the possibility of triggering due to the uncertainties associated with future scenarios, and (v) the reduction of energy consumption, which tends to be greater with a higher triggering frequency of the Tariff Flags.

3.1. Total demand reduction

To analyze the effects of the DRP, taking the uncertainties associated with future scenarios into account, 1200 scenarios were simulated. Considering the demand response described in Sections 2.4 and 2.5, Fig. 4 presents the expected demand reduction from 2014 to 2017. In 2014, the mechanism was studied by the government on an experimental basis, in which no charging for consumers took place. In this paper, the results show system's response as if the mechanism was effectively applied, i.e., not only on an experimental basis (as stated by ANEEL for this specific year) but in fact charging the consumers. As seen, a greater DRP impact would occur in the first year, when the application of the Tariff Flags would induce the reduction of energy consumption, which, in turn, would

[6] Energy Spot Price (*PLD*) is a *CMO* bounded by floor and cap price.

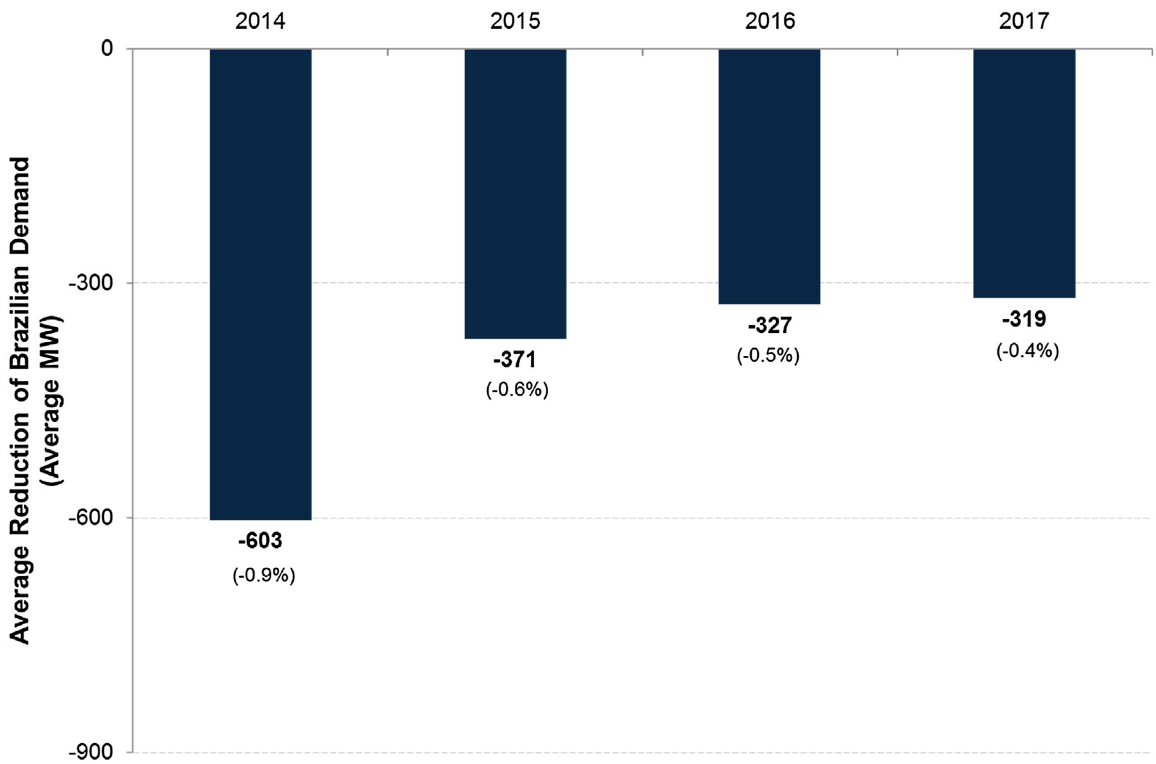

Fig. 4. Average reduction of the Brazilian total demand.

reflect in the system operation, ultimately causing a reduction of the Tariff Flag triggering in subsequent years.

Fig. 5 presents the accumulated probability of the Brazilian demand reduction for all simulated scenarios. By analyzing all different possible scenarios, it is clear that although the expected average reduction is not greater than 0.9% of the total demand, there are scenarios in which higher reductions (up to 2.6%) would be expected in 2014. These results show that the Tariff Flag application would have a stronger effect in all scenarios in the first year, and the subsequent effects would be weaker in the following years.

3.2. *Changes in the* PLD *of each submarket*

To evaluate the impact of the Tariff Flag application in the *PLD*, the simulations were performed to calculate the annual average of *PLD* values from 2014 to 2017. Fig. 6 presents the *PLDs* obtained in the inelastic and elastic cases for each submarket. Taking both cases into account, the results indicate a greater *PLD* reduction from 2015 to 2017 for all submarkets. The *PLD* reduction over the years was also observed in the results with the risk-neutral approach [16] and is justified mainly by the current unfavorable hydrological conditions and reservoir levels. However, in comparing these results obtained through the risk-neutral approach with the results taking the risk-averse approach into account, it is observed that the annual average *PLD* is higher in all years in the second case because the risk aversion enhances the preventive thermal dispatch to protect the system against unfavorable scenarios.

Moreover, the difference between the inelastic and the elastic case is explained by the Tariff Flag application. Comparing both cases, the DRP results in a lower annual average *PLD*. Furthermore, the observed short term impacts on these values were in general greater than the long term ones. The explanation is that with high *PLD* values in the first year, the Tariff Flag mechanism results in a short term demand reduction by forcing a consumer adjustment in the following months of the Tariff Flag application. By facing a lower demand, the system operating policy meets the demand dispatching in average cheaper thermal plants, directly reducing the expected *PLD*. For the following years, even in the inelastic case, the *PLD* values tend to be lower than the Yellow Flag threshold value (200 R$/MWh), which consequently reduces the difference between the annual average *PLD* in the inelastic and elastic cases. It is worth emphasizing that in some scenarios, the *PLD* values will be higher than the threshold values of the Yellow and Red Flags; thus, the effects of the DRP are observed in these scenarios and will be further illustrated in the following section in which the total operating costs are shown.

3.3. *Total system operating cost*

As explained in the previous section, by facing a lower demand, the system operating policy meets the demand dispatching in average cheaper thermal plants. The hydrothermal dispatch change and the reservoir levels tend to increase. These effects result in the direct reduction of the expected *PLD* and in the total operating cost of the entire system.

In Fig. 7, the total operating cost of the thermal dispatch is presented. As seen, the Tariff Flag application results in a 15% reduction of the total operating cost in 2015, which is almost double the reduction observed in 2014. Furthermore, there is a R$ 2.1 billion reduction in the system operating cost from 2014 to 2017, which is a representative amount.

3.4. *Probability of triggering the Tariff Flags*

The DRP application is also expected to change the triggering pattern over the course of months. To estimate the probability of triggering the Tariff Flags, the number of scenarios in which the PLD is higher than the pre-defined threshold values of each flag in both

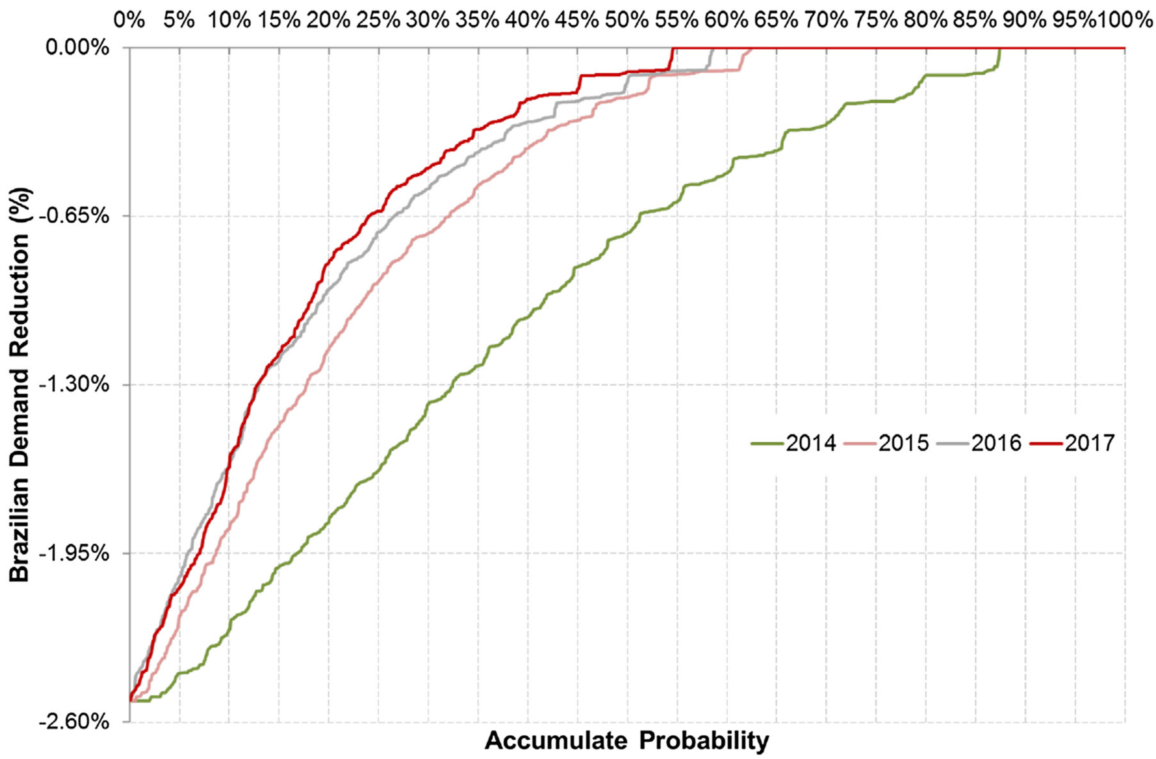

Fig. 5. Accumulated probability of demand reduction of the Brazilian system.

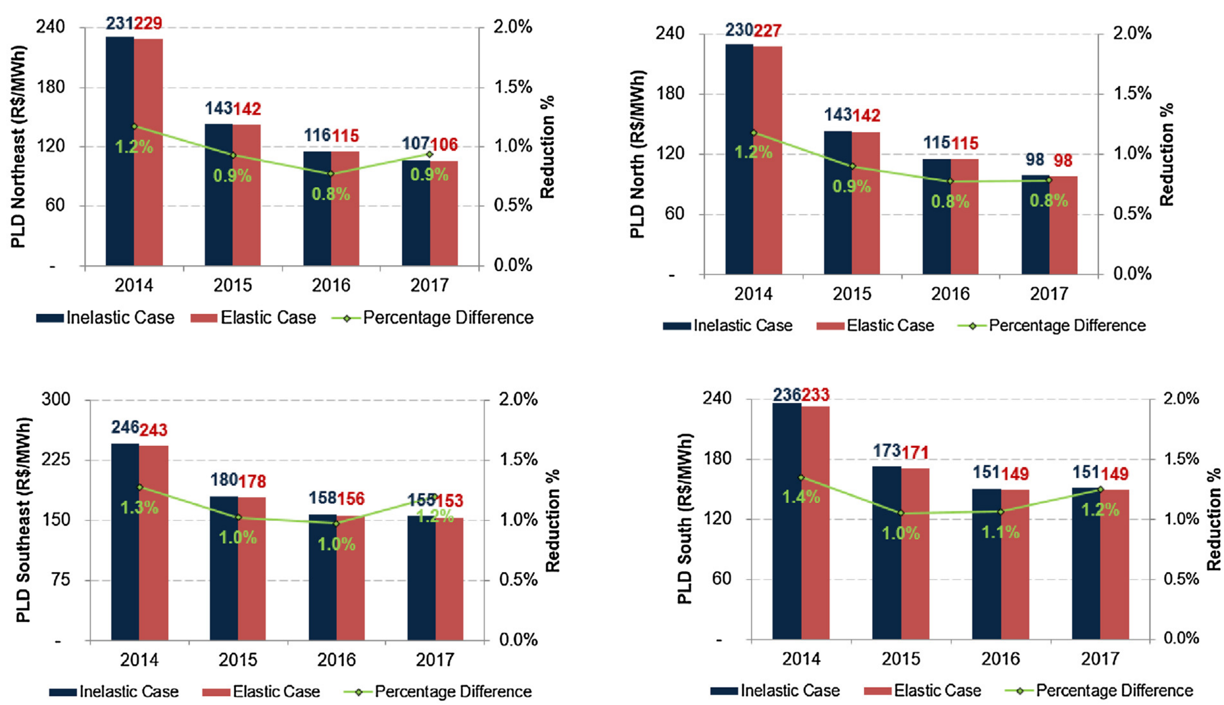

Fig. 6. Annual average PLD for each submarket.

cases (Cases 1 and 2) is counted. To illustrate these changes, Table 5 shows the probabilities of the Southeast/Central-West submarket. For the other submarkets, a similar pattern was observed.

As can be seen in Table 5, the probability of triggering the Yellow Flag increases in the first year and decreases over the following two years in the elastic case. In 2014, as the annual average *PLD* is in the yellow flag range (as shown in Subsection 3.2), the direct consequences are a representative reduction in the Red Flag's triggering probability and a higher incidence of intermediate *PLDs* resulting in an increased probability of triggering the Yellow Flag in the elastic case compared to the inelastic case.

Furthermore, the demand response causes a representative reduction in the occurrence of high prices that directly reflects in the lower Red Flag triggering probabilities. This flag is trigged in 52% of the scenarios in 2014 in the inelastic case (Case 1) and 24% in the elastic case (Case 2). For the following years, it is possible

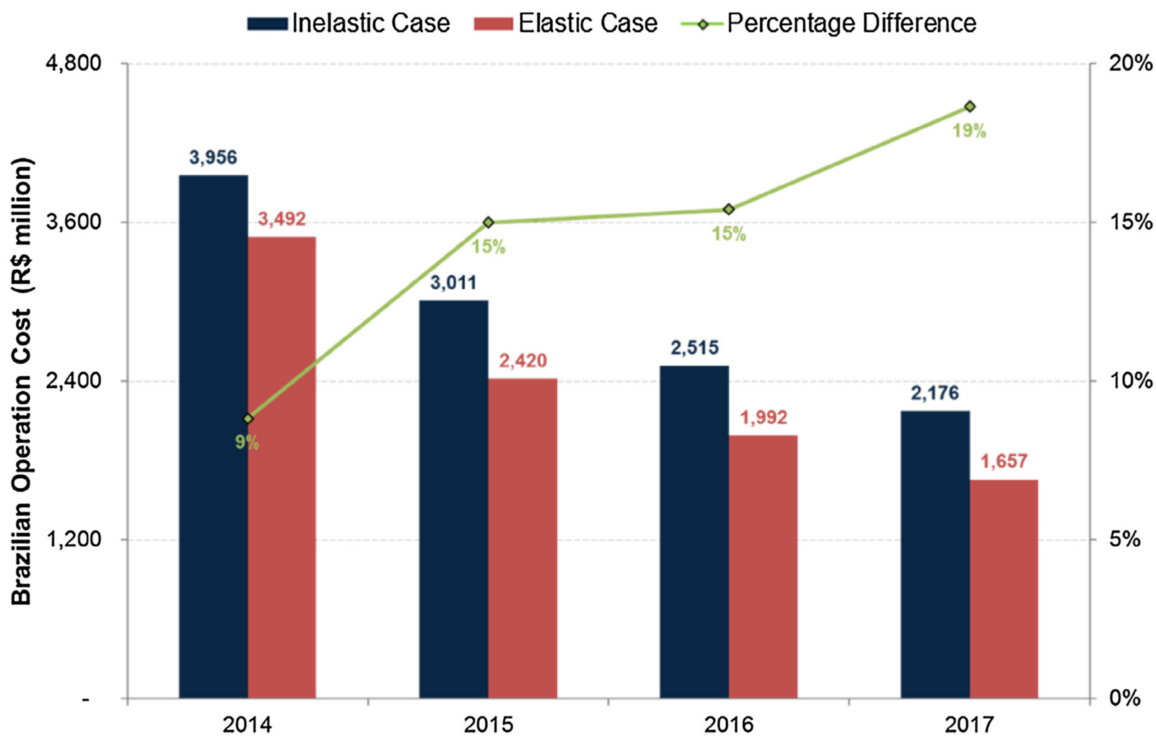

Fig. 7. Annual total operating cost due to the thermal dispatch.

Table 5
Tariff Flag triggering probability of the Southeast/Central-West submarket.

Yellow Flag	2014	2015	2016	2017
Inelastic case	0.25	0.27	0.24	0.22
Elastic case	0.27	0.19	0.17	0.22
Red Flag	**2014**	**2015**	**2016**	**2017**
Inelastic case	0.52	0.33	0.29	0.08
Elastic case	0.24 bn	0.14	0.11	0.08

to observe that the probability of triggering the Red Flag is always lower in the elastic case than in the inelastic case, which highlights the positive result of the DRP application.

3.5. Investment recovery reduction of distribution companies

Apart from the extra revenue due to the Tariff Flag application for distribution companies, an energy consumption reduction due to the PED will represent a reduction in the cash flow and, consequently, a reduction of investment recovery. From the total energy consumption reduction previously presented, it is possible to calculate the effects on the expected losses (on average) for all distribution companies in Brazil.

Fig. 8 summarizes the results of investment losses for all distribution companies due to the energy consumption reduction experienced by the Tariff Flags application. As expected, in 2014, the greatest lost is experienced. It is important to highlight that the losses were calculated based on the expected value of all distribution companies. For a distribution company with more availability contracts, the impact of such losses is even greater.

By analyzing each scenario separately, the investment losses are even higher. Fig. 9 illustrates the investment losses for each scenario, which reaches almost 450 million for some specific scenarios in 2017.

3.6. Impact of the Tariff Flags on consumers

The Tariff Flag mechanism implementation will certainly not immediately benefit consumers, in contrast to the “stability” of prices, in which they are charged a set tariff over the period of one year until the next tariff readjustment. Nevertheless, the inexistence of an immediate benefit does not hinder the future benefits, in the medium or long term, as shown in the previous section. Therefore, before thinking about the regulatory issues of a DRP implementation, it is important to perform simulations to measure the impact of the DRP on consumers, focusing on assuring that the best decision has been made. Needless to say, the possibility of energy management is positive for consumers. However, *ANEEL's* proposal may also be interpreted imposing an additional burden to captive consumers, i.e., if the process is not carried out carefully, a straightforward proposal can become a questionable decision. To highlight the Tariff Flags effects to the consumers, this subsection presents the expected reduction for consumers of the three different economic sectors: residential, industrial and commercial. In addition, an analysis of the taxes[7] applied to the energy tariff is performed.

The tariff with taxes incorporated can be calculated as follows:

$$P_T = \frac{T_T}{1 - (PIS + COFINS + ICMS)} \tag{2}$$

where T is the original tariff without taxes and P_T is the tariff currently applied to the consumers, including taxes. To quantify the effects of the Tariff Flags, two studies were performed: first,

[7] The taxes are: (i) Social Integration Program (*PIS*) and Contribution for the Financing of Social Security (*COFINS*), which present an average aliquot of 5.0%; (ii) tax on the Circulation of Goods and Transportation and Communication Services (ICMS), which present an average aliquot of 25%. It is important to mention that the taxes can be different in each state of the country and for the purposes of this study, the national average of the taxes were used.

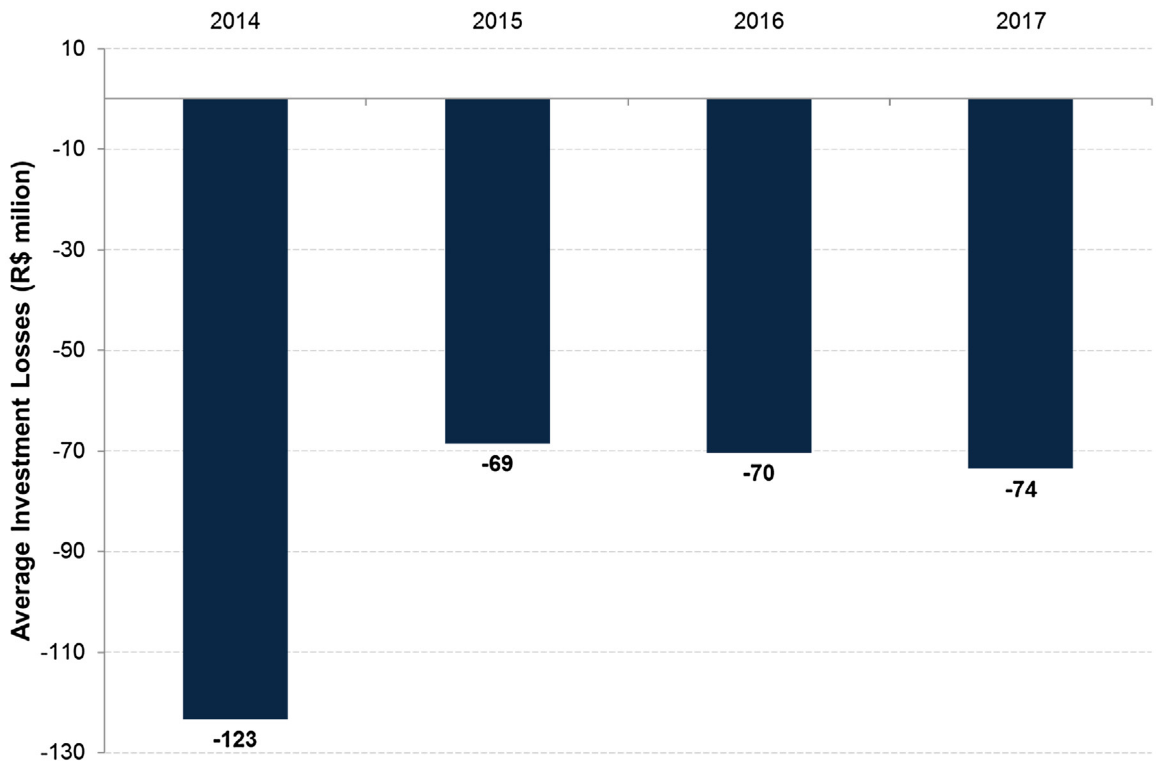

Fig. 8. Average investment losses of distribution companies.

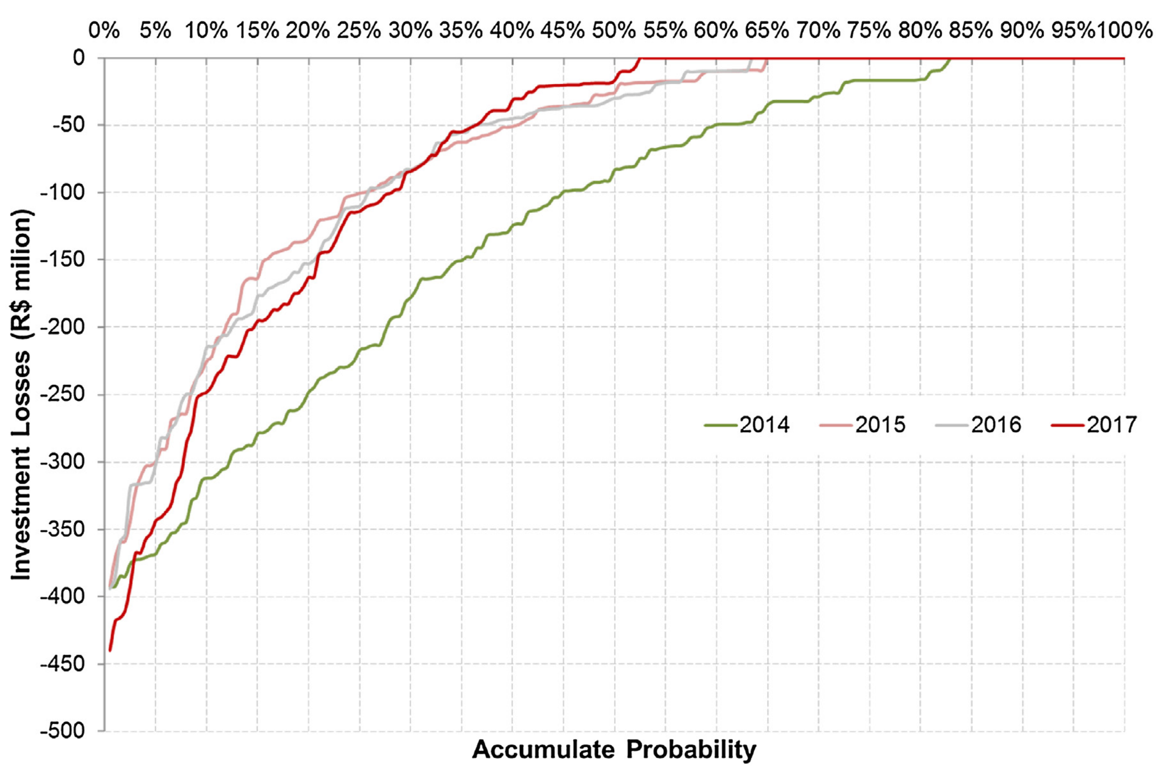

Fig. 9. Investment losses of distribution companies by scenarios.

analyzing the impact of the Tariff Flags without taxes on energy consumption reduction, and second, incorporating the taxes on the Tariff Flags. It is plausible to state that the taxes are incorporated, and these studies aim to highlight their end effects on the energy tariff.

Tables 6 and 7 present the estimated effect of the Yellow and Red Flags on energy consumption. The original tariffs (T) are the national average value of the tariff calculated by *ANEEL* [22]. The estimated tariff applied to the consumers for each sector incorporating the taxes (P_T) was calculated by expression (2). The

Table 6
Yellow Flag impact without the taxes.

Economic sector	T (R\$/MWh)	P_T (R\$/MWh)	YF (R\$/MWh)	$P_T + YF$ (R\$/MWh)	ΔP (%)	$\varepsilon_{Q,P}$	ΔQ (%)
Residential	285.72	408.17	15.00	423.17	3.67	−0.146	−0.54
Industrial	229.28	328.54	15.00	342.54	4.58	−0.545	−2.50
Commercial	269.97	386.67	15.00	400.67	3.89	−0.174	−0.68

Table 7
Red Flag impact without the taxes.

Economic sector	T (R\$/MWh)	P_T (R\$/MWh)	RF (R\$/MWh)	$P_T + RF$ (R\$/MWh)	ΔP (%)	$\varepsilon_{Q,P}$	ΔQ (%)
Residential	285.72	408.17	30.00	438.17	7.35	−0.146	−1.07
Industrial	229.28	327.54	30.00	357.54	9.16	−0.545	−4.99
Commercial	269.97	385.67	30.00	415.67	7.78	−0.174	−1.35

Table 8
Yellow Flag impact with the taxes incorporated.

Economic sector	T (R\$/MWh)	P_T (R\$/MWh)	YF_T (R\$/MWh)	$P_T + YF_T$ (R\$/MWh)	ΔP_T (%)	$\varepsilon_{Q,P}$	ΔQ_T (%)
Residential	285.72	408.17	21.43	429.60	5.25	−0.146	−0.77
Industrial	229.28	328.54	21.43	348.97	6.54	−0.545	−3.57
Commercial	269.97	386.67	21.43	407.10	5.56	−0.174	−0.97

Table 9
Red Flag impact with the taxes incorporated.

Economic sector	T (R\$/MWh)	P_T (R\$/MWh)	RF_T (R\$/MWh)	$P_T + RF_T$ (R\$/MWh)	ΔP_T (%)	$\varepsilon_{Q,P}$	ΔQ_T (%)
Residential	285.72	408.17	42.86	451.03	10.50	−0.146	−1.53
Industrial	229.28	327.54	42.86	370.40	13.08	−0.545	−7.13
Commercial	269.97	385.67	42.86	428.53	11.11	−0.174	−1.93

Yellow Flag tariff (YF) and Red Flag tariff (RF) are 15 R$/MWh and 30 R$/MWh without taxes. The price variation is the different between the tariffs applied to the consumers (P_T) and the new tariff, in percentage. The consumption reduction (ΔQ) due to the price variation was estimated by using the same aforementioned PED ($\varepsilon_{Q,P}$).

As seen, for the residential and commercial sectors, the expected energy reduction impact will experience, on average, approximately 0.6% of reduction when the Yellow Flag is applied and 1.2% when the Red Flag is applied. The expected reduction in the industrial sector will be 2.5% for the yellow Flag and 4.99% for the Red Flag, which can have a significant effect on the economy of the country as a whole.

When the taxes are applied to the Tariff Flag mechanism, the energy reduction will be even higher. To incorporate the taxes into the Tariff Flags and calculate the new Yellow (YF_T) and Red (RF_T) Flag increments, the following expressions were used:

$$YF_T = \frac{YF}{1 - (PIS + COFINS + ICMS)} \tag{3}$$

$$RF_T = \frac{RF}{1 - (PIS + COFINS + ICMS)} \tag{4}$$

Tables 8 and 9 present the expected consumption reduction due to the Tariff Flag application incorporating the taxes. In this case, the effect on the industrial sector can be greater than 7%. It is important to emphasize that the estimated values are calculated taking into account a national average tariff for each economic sector.

Due to the different contract portfolios of the distribution companies, the variation range of the tariff in Brazil is high, which means that the effect of the Tariff Flags can be even higher for some consumers. This is certainly an important issue that should be faced and deeply discussed among the agents through a public hearing before the implementation of the proposed DRP.

4. Conclusion and policy implications

In this work, a Brazilian Demand Response Program called the Tariff Flag mechanism was qualitatively and quantitatively analyzed. The main objective of this mechanism is to apply to the captive market a short-term economic signal, i.e., an increase in the energy tariff that reflects the current power generation costs. More than signalizing the system's current condition, this mechanism aims to minimize the eventual differences between costs and revenues of the utilities (because the energy tariff has only an annual readjustment) and contribute to the optimization of the system's electricity and energy resources.

The proposed mechanism was evaluated through simulations of Brazil's long-term electric energy system operation considering the new risk-averse methodology of the system operating policy. All simulations and analyses were conducted using real information on the Brazilian electrical system for each economic sector as well as the price elasticity of demand (PED) provided by the literature.

The simulation results of the long-term hydrothermal operation have shown that demand response indeed has positive effects on the system's operation, such as: (i) reduction of thermal dispatch (as well as their associated costs); (ii) improvement in the reservoir levels (which increases the storage energy) and (iii) reduction of the total operating cost of the system. Furthermore, it was also observed that the end effects of the system's operating optimization, taking this mechanism into account, are ultimately reflected in the *PLD* values for the following months, which, in turn, affects the dynamics of the thermal dispatch, the flag-triggering process and consequently the demand response.

Furthermore, the effects of this DRP on the end consumers were also evaluated. It was noticed that the intensity of the demand response of each economic sector depends not only on the adopted PED but also on the energy tariff that is applied. As seen, the most affected sector will be the industrial one, and the expected reduction of this sector will be 3.57% and 7.13% (including fees) according to the Yellow and Red flags, respectively, which can have a significant effect on the economy of the country as a whole. Consequently, sensitivity analyses based on PED values and also different Tariff Flag economic signals consist in an important recommendation for future work in order to evaluate impact variations of the proposed DRP.

From the utilities' point of view, the reduction of energy consumption due to the demand response already causes a loss of revenue. In addition, the fact that the same increment for the Yellow and the Red Flags will be adopted for all distribution companies presents an important effect because companies with a low number of availability contracts will have extra cash flow when the flags are triggered, without presenting compatible cost increments, while companies with a high number of availability contracts will not have enough revenue to compensate for their increased costs. Therefore, further studies should be performed to avoid the representative losses that could affect the financial health of the distribution companies.

In addition, the demand response may create an additional source of uncertainty about the demand behavior to the utilities, which directly influences their network planning and their energy purchasing in the public auctions held by the government.

In conclusion, if an effective awareness campaign for customers is not conducted, the mechanism implementation may be ineffective. Therefore, the wide disclosure of available benefits is extremely important.

Finally, before considering the regulatory issues of a DRP implementation, it is important to perform simulations to measure the effect of the DRP on consumers, focusing on ensuring that the best decision has been made. Needless to say, the possibility of energy management for consumers is positive and has positive effects on the system operation.

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