Renewable Energy 133 (2019) 873–882

Contents lists available at ScienceDirect

Renewable Energy

journal homepage: www.elsevier.com/locate/renene

Hydropower revenues under the threat of climate change in Brazil

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ARTICLE INFO

Article history:
Received 8 February 2018
Received in revised form
12 September 2018
Accepted 10 October 2018
Available online 11 October 2018

Keywords:
Assured energy
Hydropower generation
Climate change
Water-energy nexus
Hydro plants revenue

ABSTRACT

This work analyzes the impacts of climate change in the revenues of hydropower plants. One important input for designing and evaluating investment opportunities in hydropower is the water inflows historical data. Unfortunately, the use of such information alone may not project well the future power generation due to the influence of climate change in the water inflow patterns. This paper introduces spatio-temporal information of the future climate into the operational planning of the Brazilian hydropower system. Global climate models from IPCC are considered along with downscaled regional climate models. Our results at the individual hydro plant level show the importance of taking into account climate change information when performing hydro generation planning studies.

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1. Introduction

There is a growing consensus about the importance of renewable sources for reducing CO_2 emissions associated with electricity generation [1]. Despite being of "low cost" (the operational cost associated with the use of water, wind, and sunlight is virtually zero), renewables have a large uncertainty about their future availability. In the case of hydro, reservoirs allow a partial reduction in the dependence on water inflows because of their regularization capabilities. However, the current practice in countries such as Brazil and Canada is to plan and construct run-of-the-river hydro plants due to environmental issues associated with the allocation of large regularization reservoirs. Other renewable sources such as wind, solar, and biomass also depend on climate conditions, which may affect their intra-hour, monthly or seasonal production.

The increase in renewable penetration in electric power systems is a trend worldwide. Therefore, the participation of renewables in the global energy matrix has been increasing as well as the power generation dependence on climate variables, which directly affects future operational and planning processes in power systems. Changes in climate patterns have been more intensive and noticeable over the past decades [2–4]. There are arguments that attribute these changes to human and society developments [5]. The authors in Ref. [4] argue that climate change effects on electricity supply from renewables present large geographical variability due to differences in expected changes to climate variables such as temperature and precipitation. According to [4], the research boundaries have advanced in the recent past, but a significant amount of new research is needed to understand and evaluate climate change effects on electricity markets.

Hydropower plants are among the most vulnerable technologies to climate change, when compared to other conventional generation technologies, as the reduction in precipitation directly affects the water inflows used as the "fuel" to move the turbines/generators and produce electricity. As noted by Ref. [3], the attractiveness of hydropower projects is extremely dependent on long-term assessment of generation capacity to support capital investment, and that may considerably change under water inflows reduction caused by changes in climate. In countries with high dependence of this electricity generation technology, such as Brazil that has about 80% of its electricity coming from hydro plants [5], new research developments for the future water-energy nexus are crucial for planners and policy designers. As concerns with climate change effects to our society have scaled-up in the last decades, countries around the world started to devote considerable amount of resources to promote new research and development projects

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https://doi.org/10.1016/j.renene.2018.10.050
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Nomenclature

Abbreviations

AE	Assured Energy
ARR	Aggregate representation of reservoirs
CP	Critical period
EPE	Brazilian federal energy planning company
INPE	Brazilian Institute of Space Research
Eta	Regional climate model
FE	Firm Energy
EGS	Existing generation system
FGS	Future generation system
GCM	Global climate model
HTSP	Hydro-thermal scheduling problem
HadCM3	Third version of the Hadley Centre global climate model
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent system operator
MCE	Expansion marginal cost of electricity
MGB	Large basin rainfall-runoff hydrological model
OFER	Optimizer of Firm Energy Rights
PAR	Periodic autoregressive model
P1, P2, P3, P4	1961–1990 (P1), 2011–2040 (P2), 2041–2070 (P3) and 2071–2100 (P4)

Indices and Sets

$CP \subseteq T$	Subset of months that define the critical period of the hydro system
$i \in I$	Set of hydropower plants
$m \in M_i$	Set formed by hydro plants located immediately upstream of hydro plant i
$t \in T$	Set of monthly time stages

Parameters

A_i^t	Incremental water inflow in the river that supplies hydro plant i, at stage t, expressed in $[m^3/month]$
h_{eq}^i	Equivalent net head of hydro plant i, expressed in $[m]$
HL_i	Hydraulic losses at hydro plant i due to the water flow though pipelines, expressed in $[m]$
$\overline{Q_i}$	Maximum turbine outflow of plant i, expressed in $[m^3/month]$
$\overline{V_i}$	Maximum storage volume of hydro plant i, expressed in $[m^3]$
$\underline{V_i}$	Minimum storage volume of hydro plant i, expressed in $[m^3]$
$\overline{\theta_i}$	Hydro plant i average tailrace level, expressed in $[m]$
ρ_{eq}^i	Equivalent productivity of hydro plant i, expressed in $\left[\frac{MW \cdot month}{m^3/month}\right]$
ρ_{sp}^i	Specific productivity of hydro plant i, expressed in $\left[\frac{MW \cdot month}{\frac{m^3}{month} \cdot m}\right]$
$\gamma_{k,i}$	k-th polynomial coefficient that represent reservoir head and volume of hydro plant i

Decision variables

AE_i	Individual assured energy of the hydro plant i, measured in average MW, or $[MW \cdot month]$
FE_i	Individual firm energy of the hydro plant i, measured in average MW, or $[MW \cdot month]$
GFE	System firm energy, measured in average MW, or $[MW \cdot month]$
HE	Hydropower energy fraction of the system assured energy, measured in average MW, or $[MW \cdot month]$
N_{CP}	Number of months in the critical period
PG_i^t	Average power generated by hydro plant i, at stage t, measured in average MW
Q_i^t	Turbined outflow of hydro plant i, at stage t, expressed in $[m^3/month]$
S_i^t	Water spillage outflow of hydro plant i, at stage t, expressed in $[m^3/month]$
V_i^t	Water storage volume in the reservoir of hydro plant i, at stage t, expressed in $[m^3]$

Functions

$\varphi_i(V_i)$	4-th order polynomial to represent reservoir head and volume of hydro plant i

aimed to understand potential impacts of these changes to critical infrastructure areas including hydropower.

In the US, an assessment of the climate change impacts in the federal hydropower plants was conducted in Ref. [6] using a runoff–based approach where global and regional climate models results were applied to predict runoff and hydro generation until 2039. Other climate-hydropower analysis in the US can be found in Refs. [7,8]. For example, in Ref. [7] the authors found that a large reduction in mountain snowpack and associated reduction in natural water storage caused by climate change would potentially reduce up to 40% of hydropower generation in the Colorado River by mid-century. The work presented in Ref. [8] uses a combination of climate scenarios and mathematical models to analyze the management of water resources in Portland, Oregon and portions of California; the study concludes that the management of existing water resources in these regions is likely to be more challenging in the presence of climate change. The work presented in Ref. [9] carries out a qualitative analysis of climate change impacts in hydropower affecting the electricity market in Europe; the work argues that hydropower generation can be significantly reduced in several regions of the continent due to modification in hydrology and sedimentation. In Ref. [10], the Swiss and the Italian Alps are studied under the threat of climate change, where the authors point out to the problem complexity, as it should associate technical, physical and economic components of systems. The work of [10] also presents the importance of regional analysis as reductions or increases in annual water runoff (and consequently hydropower) were expected depending on the location of the plant.

Authors in Ref. [8] have argued that ignoring the potential impacts of changes in climate, because of limitations in current modeling methods, will likely to result in significant unexpected economic and social costs for the future. In Ref. [11] a methodology to assess financial risk in hydropower facing climate change is proposed and applied to a single hydro plant in the Zambezi river, where simulation results suggest that, for the set of climate change scenarios considered, the risk (measured by variance in energy production) associated to the hydro project is likely to increase. In Ref. [12], climate change projections from the Canadian regional climate model were used as input to a dynamic stochastic optimization model designed to adapt reservoir operating rules, which are later tested in simulation models to obtain hydropower production for 2010–2099. The work presented in Ref. [13] argues that it is challenging to use climate change impact assessment results due to differences between typical results and decision maker needs. They proposed a decision analysis framework to support decision-making by joining stochastic analysis for risk identification and global climate models (GCMs) projections to estimate such risks. A similar methodology was later applied in Ref. [14] to plan infrastructure investments in the Middle Niger River basin. As one can notice, previous literature has successfully used mathematical models to evaluate climate change effects in hydropower. Also, several papers have emphasized the importance of representing regional details when analyzing new generation investments under the threat of climate change.

The foundation of this work is based on a research project [15], which aims to evaluate the potential reduction in assured energy (AE) for hydropower at the system level [16,17] caused by water inflows affected by changes in climate variables. We use simulation results from the GCM HadCM3 [18,19] and the analogous downscaled model Eta [20,21] in combination with a large basin rainfall-runoff hydrological model (MGB) [22] to represent future projections of water inflows at each hydro plant in the Brazilian system. Climate models consider the representation of variables such as temperature of the ocean surface, vegetal cover, concentration of CO_2, air humidity, wind, atmosphere pressure, and soil. Water inflows for each hydro basin produced using climate information in four different periods are used to evaluate hydropower. The main goal of this paper is to analyze potential impacts that changes in climate may produce in the individual generation levels of hydro plants. In this novel approach, we create a framework to segregate the system level assured energy, computed considering changes in climate, into values for individual power plants. We aim to advance the analysis from Ref. [15–17] and improve by adding a more detailed spatial-resolution of the hydro plants that compose the system. To our knowledge, this is the first analysis that attempts to capture the potential impacts of climate change at the individual hydro plant level for a hydro-dominant and interconnect power system as the Brazilian system. Therefore, given the importance of the regional characteristics in analyzing the attractiveness of each hydropower project [3] we aim to contribute with the literature and provide a framework that is general and can be applied to evaluate individual hydropower projects and inform system planners.

We note that it is beyond the scope of our work to construct risk estimates based on different GCMs and climate scenarios or to construct a decision-making framework for investment planning facing climate change. Instead, we aim to inform and discuss potential consequences to existent and planned hydropower plants in Brazil under different climate change scenarios. Similar to [12], we rely on optimization models designed to make management decisions in hydropower. However, in our case, we use stochastic and deterministic optimization models to compute system energy measures. We investigate potential changes in AE allocated to each individual hydro plant, instead of system level values as in Ref. [17]. Furthermore, we evaluate potential economic impacts to hydropower plants at the system level.

The remainder of this paper is divided as follows: Section 2 presents the methodology related to assured and firm energy, climate models and scenarios used in this work. The framework of the analysis and the steps followed to obtain data and construct the results are also described in Section 2. Section 3 presents simulations results and a discussion about the findings. Section 4 concludes this paper.

2. Methods

2.1. Energy production segregation in hydropower systems

In a centralized dispatch scheme, the independent system operator (ISO) is responsible for determining each power plant dispatch (hydro, coal, gas, nuclear, etc) at each time period to satisfy system demand at minimum cost. In terms of hydro plants, the ISO determines water usage from reservoirs and consequently the electricity production from these plants. Theoretically, one advantage of this operation scheme is that the set of hydro plants will operate in a condition near to optimality [23]. However, one question that arises is: how should one fairly divide this energy among hydro plants that compose the system? The solution adopted by the electricity regulatory agency in Brazil was to establish and use two metrics: the AE and the firm energy rights (FE) [24]. We evaluate these metrics further in Section 3 using information from various hydrological scenarios and periods, but first we detail the processes to characterize and obtain them.

2.2. System assured energy

The system AE is a hypothetical amount of energy that could be generated by a power generation system for a pre-determined level of supply risk [17]. In the Brazilian interconnected power system, the system AE is calculated using the mathematical model presented in Ref. [25] that aims to minimize the production costs of electricity to supply the system demand considering the operation of hydro and thermal plants. This model represents a stochastic optimization version of the classic hydro-thermal scheduling problem (HTSP) [26]. In this context, the methodology used in Brazil considers an aggregate representation of reservoirs (ARR) to model the hydro plants inside a specific region [16,27]. The ARR is used to reduce the size of the mathematical model and the computational effort needed to carry out optimization runs. In the ARR, multiple reservoirs are aggregated into a single equivalent reservoir with generation and storage capacities proportional to the sum of the individual capacities of the hydro plants inside a region. By following this approach, the HTSP solution provides generation targets for each aggregate reservoir instead of individual hydro plants. We consider four ARRs to represent the different regions of the Brazilian electric power system (Southeast/Central West, South, Northeast and North), similar to what was previously done in Ref. [25].

In this paper, we follow the AE convergence criteria for the HTSP as adopted in Ref. [17], where the system AE is defined as the total energy available in the system at a risk level of 5% of not supplying the demand. The AE convergence criterion for demand supply risk is defined to be 5% with a tolerance of $\pm 0.1\%$, e.g. when considering 2000 synthetic series of inflows the supply has to meet the total demand in 1900 ± 2 synthetic series, at every time stage of the planning horizon. These synthetic series are generated by a periodic autoregressive model (PAR) [28] that uses as input the historical hydrological series of water inflows. This paper follows the approach from Ref. [17] and uses the hydrological series coming from the MGB model [22] (that transforms climate variables into water inflows) as the input for the PAR model in order to perform the AE simulations. After computing the system AE, this variable is divided into two components, one that is attributed to the hydro energy generation (*HE*) and the other to the thermal energy generation. This segregation is made using a metric that values the monthly generation based on the marginal cost of operation, which is described in Ref. [16].

2.3. Firm energy rights evaluation

In general terms, the system FE is the maximum amount of energy that a system can continuously generate without the occurrence of load deficits and considering the repetition of the historical water inflows sequences. Once the system FE is computed, the individual FEs (FE_i) are determined as the average generation of a hydro plant during the most severe drought period registered in the historical water inflows data. As consequence of this definition, the system FE is the sum of FE_i for all hydro plants that participate in that system.

To compute the FE, we use an optimization model that aims to maximize the amount of energy generated by hydropower plants considering the historical water inflow series. This model is subjected to structural constraints to ensure that the electricity generation in each month should be the same throughout the simulation period [29]. During the process to obtain the system FE, the model uses the storage energy curve of the simulated system to first find the most severe drought in the simulated history. This period corresponds to the time interval where the system goes from a maximum energy storage to a minimum energy storage without intermediate refills, and it is called critical period (CP). After obtaining the CP, the FE_i for each hydro plant is computed as the average generation of the plant during the CP. The optimization model developed here to compute the system FE and FE_i is defined in (1)–(10).

$$\max \ GFE \tag{1}$$

$$\text{s.t. } V_i^{t+1} = V_i^t - Q_i^t - S_i^t + A_i^t + \sum_{m \in M_i} \left(Q_m^t + S_m^t\right) \ \forall \ i \in I, t \in T \tag{2}$$

$$GFE = \sum_{i \in I} PG_i^t \quad \forall \quad t \in T \tag{3}$$

$$0 \le Q_i^t \le \overline{Q_i} \quad \forall \quad i \in I, t \in T \tag{4}$$

$$\underline{V_i} \le V_i^t \le \overline{V_i} \quad \forall \quad i \in I, t \in T \tag{5}$$

$$S_i^t \ge 0 \quad \forall \quad i \in I, \quad t \in T \tag{6}$$

where,

$$PG_i^t = \rho_{eq}^i Q_i^t \quad \forall \quad i \in I, \quad t \in T \tag{7}$$

$$\rho_{eq}^i = \rho_{sp}^i h_{eq}^i \quad \forall \quad i \in I \tag{8}$$

$$h_{eq}^i = \frac{\int_{\underline{V_i}}^{\overline{V_i}} \varphi_i(V_i) \ dV_i}{\left(\overline{V_i} - \underline{V_i}\right)} - \left(\overline{\theta_i} + HL_i\right) \quad \forall \quad i \in I \tag{9}$$

$$\varphi_i(V_i) = \sum_{j=1}^{5} \gamma_{j,i} (V_i)^{j-1} \quad \forall \quad i \in I \tag{10}$$

The objective function (1) aims to maximize the total generated energy in each month. Constraint (2) is the hydro balance equation. Constraint (3) ensures that the energy GFE can be supplied during all the monthly time stages by the set of plants I. Constraints (4) and (5) limit the turbined outflow, and the storage volume, respectively. Constraint (6) enforces a non-negative volume of spillage. Equation (7) is a consequence of the definitions in (8)–(10), Equation (10) relates the reservoir head with the water stored volume. Equation (9) computes an equivalent net head for each hydro plant i. Equation (8) is an intermediary step to compute an equivalent productivity. Equation (7) describes the power generated by the plant i as a function of Q_i^t. It is important to notice that the model (1)–(10) is designed in terms of monthly time stages, this way, units such as $[m^3/month]$ or $[m^3]$ can be used interchangeably when describing, for example, the total turbined volume or the turbined outflow in a specific time stage t.

After solving (1)–(10) and identifying, by the storage energy curve, the months that correspond to the CP of the system, the individual FE of the plant i (FE_i) can be determined by (11). We refer to model (1)–(10) in the reminder of the manuscript as OFER (Optimizer of Firm Energy Rights).

$$FE_i = \frac{\sum_{t \in CP} PG_i^t}{N_{CP}} \tag{11}$$

2.4. Individual hydro plants assured energy

The first step to obtain individual hydro plants assured energy is to evaluate the system AE using the HTSP model [16,17]. Then, the hydro energy fraction (HE) is obtained from the system AE (AE is composed by hydro and thermal energy) as stated in Ref. [16]. The ratio between the FE_i and the system FE is used to split the HE among the set of hydro plants that compose the system. In this process, a portion of the system AE is defined for each plant (AE_i) using (12), where $i \in I$ represents the set of hydro plants that compose the system.

$$AE_i = HE \frac{FE_i}{\sum_{i \in I} FE_i} \tag{12}$$

The AE_i works as ballast for energy sales in the electricity market. In that sense, if a particular hydro plant has more AE_i it can sell more electricity through contracts and profit more. The whole process to obtain AE_i values under different climate scenarios is further detailed in Section 2.6.

2.5. Climate models and water inflow scenarios

To determine the future water inflows at each hydro plant we use climate variables output of two variations of the Eta CPTEC regional climate model (Eta-20 km, and Eta-40 km) [15], [17] designed using boundary conditions from the GCM HadCM3. The climate variables generated by the Eta model are transformed into water inflows by the hydrological model MGB [22]. These water inflows are then used as input to hydro-thermal optimization models to calculate FE_i and HE. The model HadCM3 is the third version of the Hadley Centre GCM. This model couples ocean-atmosphere information and considers anthropological impacts on climate and natural origin impacts such as volcano eruptions and solar radiation [18], [19]. This GCM model has a spatial resolution of 280 km.

To simulate and project climate decades ahead, climate models depend on how human societies will develop in terms of demographics, economics, emissions, energy supply, demand, and land and soil usage. In this paper, to represent future climate information, we use the A1B scenario from the Intergovernmental Panel on Climate Change (IPCC) [30]. The A1B scenario was selected in this work among several scenarios of greenhouse gases emissions from the IPCC on the horizon from 2000 to 2100 because it represents an average growth of future CO_2 emissions (avoiding too optimistic or too conservative assumptions) following what was previously done in Ref. [31]. This scenario supposes a rapid economic growth, global population that peaks in mid-century and declines thereafter, and the rapid introduction of new and more efficient technologies, with balanced use of all energy sources.

The HadCM3 GCM has a resolution, which cannot adequately represent the regions where the river basins are located. Therefore, dynamic downscaling techniques are employed through the use of regional climate models, which provide a more detailed spatial representation than the GCM variables [15]. We use results from the regional Eta model downscaled from the results of the HadCM3 GCM with the A1B scenario. The Eta model has shown to perform favorably against other models to represent the climate in South America [20], [21].

The Eta model depends on atmosphere information from the GCM for its lateral boundaries [20]. Because it is a regional model, Eta's resolution is higher than the current GCMs and it is adopted in the simulations with 20 km (Eta-20 km) and 40 km (Eta-40 km) resolutions. The prognostic variables of this model are air and soil temperature, wind, atmospheric pressure on the surface, air and soil humidity, turbulent kinetic energy, solid and liquid water in the clouds.

The climate variables result from Eta models are used as MGB inputs (calibrated for each river basin of the system) to generate water inflows. The MGB is calibrated using information related to characteristics of soil type and vegetation of each individual river basin considered in the analysis. The MGB model is distributed in space with a representation of each river basin in small units called mini-basins (which are interconnected by drainage systems). For more details about the MGB calibration process, the reader should refer to [15], [22]. The calibrated MGB is applied to evaluate the rainfall-runoff functions using the climate variables from the Eta models.

In this work, we consider the MGB calibrated with hydrological information using monthly data ranging from 1960 to 1990 as described in Ref. [17]. The associate water inflows of the models Eta-20 km and Eta-40 km computed by MGB, for four 30-year periods 1961–1990 (P1), 2011–2040 (P2), 2041–2070 (P3) and 2071–2100 (P4), are used to evaluate the system AE and AE_i. Period P1 corresponds to the base period used to calibrate the Eta model.

2.6. Framework of the analysis

Fig. 1 shows a flow diagram that summarizes the steps followed to determine HE, FE_i, and AE_i values. Initially, the climate model HadCM3 is simulated for periods P1, P2, P3, and P4. Then the outputs of these simulation are used by Eta-40 km and Eta-20 km to determine the climate variables that are input of MGB.

From the results of MGB, future hydrological series are obtained for the Brazilian hydropower plants. These future hydrological series are used in the OFER model to compute the individual FEs (FE_i);

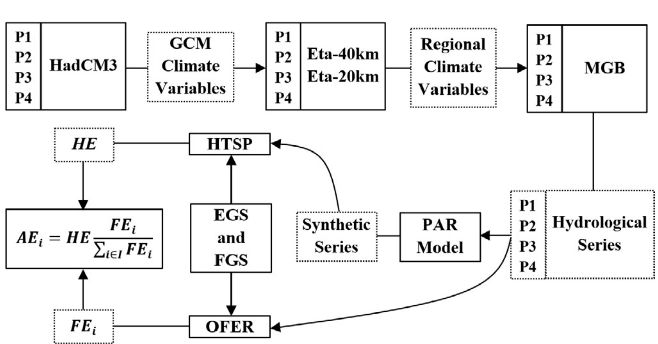


Fig. 1. Methodology flow diagram.

these series also serve as input to the PAR model [28] during the HTSP optimization process used to obtain the hydro portion of the system AE (HE). Finally, with the HE and FE_i values it is possible to compute the AE_i using Equation (12).

Simulations are performed with two different configurations of the Brazilian power generation system, the existing generation system (EGS), and the future generation system (FGS) as represented in Ref. [17]. The EGS considers only the existent hydro plants in the configuration of the ISO monthly operation program from January 2012 [32]. The FGS considers all hydro plants previously mentioned and other plants planned to enter in the system until 2030 [33]. In the EGS (FGS) there are 141 (214) hydro plants and an installed capacity of 107 (143) GW.

The EGS total installed capacity is composed of hydropower plants (38.2% with reservoir storage, 35.5% run-of-river plants and 0.7% pumped-storage), thermal power plants (16.3%, including gas-fired, coal-fired, diesel-fired and nuclear plants) and other renewables (9.1%). The FGS has several new hydropower plants in the North subsystem where the Amazonas river basin is located, and present relevant differences in installed capacities, with hydropower accounting for 66.7% (31.7% with reservoir storage, 34.8% run-of-river plants and 0.5% pumped-storage), thermal representing 17% and other renewables 16% of the total.

The total installed generation capacity per subsystem in the EGS (FGS) are: Southeast: 60% (46%); South: 16% (14%), Northeast: 14% (17%); and North: 10% (23%). These subsystems (representing the country regions) are interconnected using transmission lines that enable optimization of water resources among river basins and other energy resources. The electric transmission capacities between the subsystems depend on physical constraints of the transmission lines, which are kept constant along the simulation following the current conditions of the system [32], and the transmission expansion plan represented in Ref. [33].

Outputs from HTSP and OFER model runs are values for each climate model, in each 30-year period, and for each power generation system configuration. With these outputs, we determine the AE_i for each hydro plant. The analysis performed in the next Sections is divided into three parts: System Level, Subsystem Level, and Individual Plant Level.

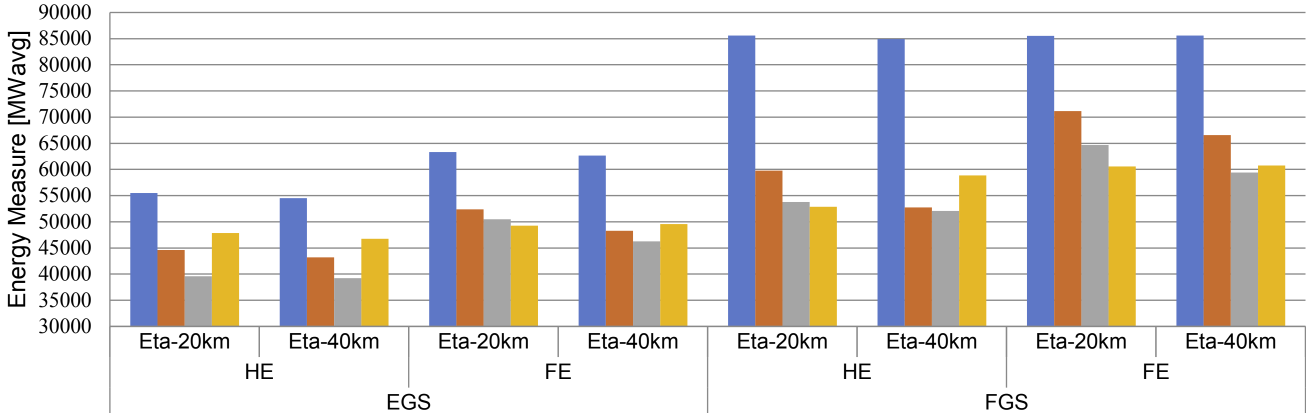
In the System Level, simulations performed and reported in Ref. [17] are used to obtain the system FE and HE values. In the Subsystem Level, the Brazilian system is divided into four electrical subsystems 1, 2, 3, and 4 that correspond respectively to the Southeast, South, Northeast, and North regions [17]. In the Individual Level, georeferenced maps are used to analyze variations in individual AEs.

3. Results and discussion

Our simulations with future climate change projections were not compared with the observed data, but instead, compared with simulated data for different periods. This approach allows any bias from the MGB model to the inflows and consequently to energy measures to be eliminated. However, we indicate that the simulation with Eta-40 km in P1 reproduced the observed system FE and AE in the EGS (FGS) with over-estimates of 1.0% (0.65%) and 3.18% (2.63%) respectively. The CP that considers the simulated water inflows in P1 has 41 months starting in 05/1968, and it is different from the official CP in Brazil (06/1949 to 11/1956), which is constructed using observed water inflow values.

3.1. System level analysis

Fig. 2 shows HE and FE values from P1 to P4 according to climate models Eta-20 km and Eta-40 km. The HE and FE values represent



	EGS HE Eta-20km	EGS HE Eta-40km	EGS FE Eta-20km	EGS FE Eta-40km	FGS HE Eta-20km	FGS HE Eta-40km	FGS FE Eta-20km	FGS FE Eta-40km
P1	55500	54529	63301	62624	85611	84913	85554	85608
P2	44624	43205	52353	48307	59777	52727	71158	66596
P3	39576	39204	50511	46270	53796	52070	64671	59438
P4	47831	46756	49280	49587	52848	58856	60588	60777

Fig. 2. System FE, and ***HE*** from P1 to P4 according to the climate models Eta-20 km and Eta-40 km.

projections of how the overall hydropower system will behave under climate change scenarios. In this case, there is a reduction trend in *HE* and FE values from P1 to P3, with a small increase from P3 to P4 in a few scenarios. Comparing the results of the EGS with the FGS, the new hydro plants of the FGS are likely to be more affected by changes in climate as the reductions in the total hydro generation are more pronounced in the FGS than in the EGS (e.g. reductions of 29.2% with respect to the FE when P1 and P4 are compared using the ETA-20km information for the FGS, while we observe 22.2% reduction in the EGS; when considering the same analysis for the *HE*, the FGS has 38.3% of reduction and 13.9% for the EGS).

Table 1 describes the CP length in months (starting month) for all simulations. Besides its importance in FE_i evaluation, the CP provides a reasonable idea of how difficult is for the system to provide a specific FE, for example, in the EGS during period P3, the Eta-20 km model indicates a CP of 103 months, this means that in order to provide its FE of 50511 average MW the system has to pass through a constant decrease in its stored energy during 29% of the months in P3, and a small change in dispatches could reduce the FE. From another perspective, a small CP indicates an abrupt reduction in the system stored energy during a short time interval. A negative impact of climate change can be observed for the overall hydropower system, according to the models used.

3.2. Subsystem level analysis

The subsystem AE is defined as the sum of all hydro plants AE_i inside a subsystem, and the relative FE is equal to the AE percentage allocated to the subsystem. Table 2 presents AE values by subsystem considering the EGS and the FGS for P1, P2, P3 and P4 using the models Eta-20 km and Eta-40 km. Fig. 3 represents graphically the values of relative FE (percentage of the AE) for all climate models and simulation periods using the EGS. Subsystems 1, 2, 3, and 4 are represented by colors blue, orange, gray, and yellow, respectively. Eta-20 km data are depicted in continuous lines and Eta-40 km data in dashed lines. Fig. 4 represents similar values using the FGS.

For the EGS, in terms of absolute growth, only subsystem 2 presents an increase in AE, when comparing periods P2, P3 and P4 with period P1 (Table 2-EGS). Subsystem 2 is the only one that tends to have AE growths between all simulation periods (Table 2-EGS), even with a smaller relative FE in P4 (Fig. 3). For subsystems 1, 3 and 4 it is possible to notice only an absolute growth in AE during the transition from P3 to P4 (Table 2-EGS). In terms of the participation in the energy generated in each period (relative FE), there is an increasing trend in the participation of subsystems 1 and 2, with a decrease in the participation of subsystems 3 and 4 (Fig. 3).

The considerations made for the EGS can be applied for the FGS with one exception. In the FGS, subsystems 2 and 4 present clear reduction trends in absolute AE between P3 and P4 (Table 2-FGS). When comparing configuration results, one can notice an increase in total hydropower participation (relative FE) of subsystem 1 (EGS: AE share of 56.3% in P1 and 59.4% in P4 – Fig. 3; FGS: AE share of 62.5% in P1 to 64.4% in P4 – Fig. 4); and a decrease in subsystem 4 (EGS: AE share of 23.2% in P1 and 13.3% in P4 – Fig. 3; FGS: AE share of 19.0% in P1 to 9.9% in P4 – Fig. 4). From the results presented in Table 2 and Figs. 3 and 4, it is possible to notice a strong correlation between the results of model Eta-20 km and Eta-40 km, with small variations in the results presented by these climate models. These variations are more significant in the EGS mainly for the subsystems 1 and 4.

Table 1
Number of months and starting month of the CP for EGS/FGS for different climate scenarios and periods.

Generation System/Climate Model		Number of Months of **CP**			
		P1	P2	P3	P4
EGS	Eta-20 km	19 (246)	31 (54)	103 (173)	42 (221)
	Eta-40 km	31 (209)	42 (54)	57 (196)	34 (219)
FGS	Eta-20 km	20 (245)	32 (53)	43 (234)	34 (219)
	Eta-40 km	18 (246)	42 (54)	67 (210)	42 (211)

Table 2
Subsystem AE for all climate models and system configurations during periods P1, P2, P3, and P4.

Generation System	Subsystem	Eta-20 km				Eta-40 km			
		P1	P2	P3	P4	P1	P2	P3	P4
EGS	1	31273	24882	22911	28422	28787	23249	21950	29615
	2	6352	8038	9323	9778	6156	7592	9028	8933
	3	5022	3448	2263	3250	5593	3553	2377	3008
	4	12852	8256	5079	6381	13994	8811	5849	5200
FGS	1	53503	36750	33731	34017	52498	31748	31310	38552
	2	6952	8566	11793	9927	6971	7051	12254	10878
	3	8904	5437	2823	3684	9155	5195	2672	4073
	4	16251	9024	5450	5220	16289	8733	5833	5353

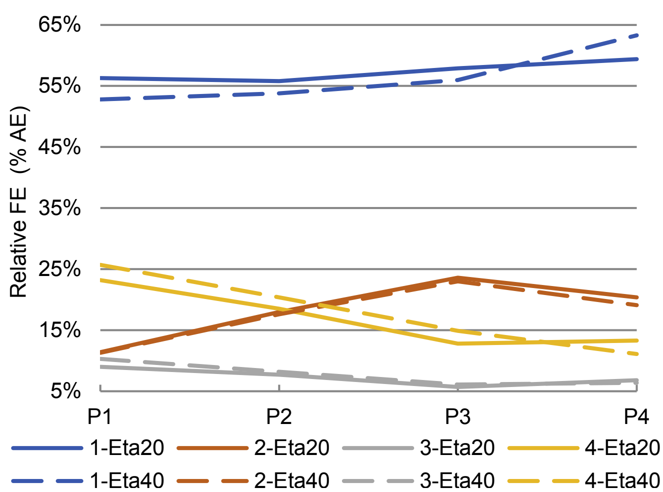


Fig. 3. Relative FE for subsystems 1, 2, 3 and 4 in the EGS.

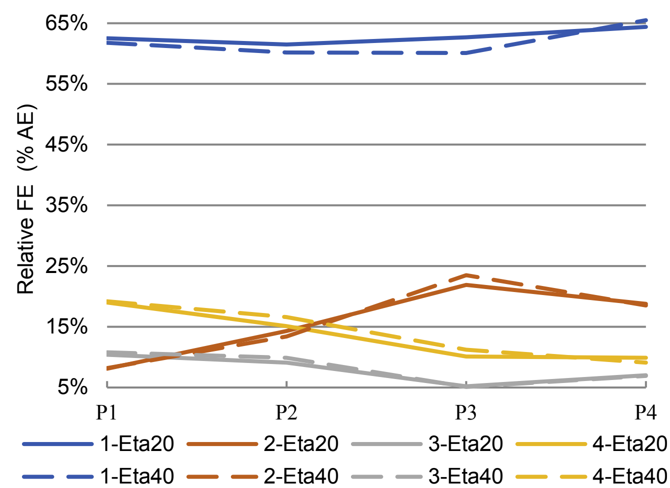


Fig. 4. Relative FE for subsystems 1, 2, 3 and 4 in the FGS.

3.3. Individual plant-level analysis

In this analysis, the Eta-20 km model is used because of its resolution and precision to represent climate variables at the hydro plants spatial level. Fig. 5 shows the results of the analysis carried out in terms of AE_i percentage variations by hydro plant. Subfigures I, II and III, represent the EGS from P1 to P2, P1 to P3, and P1 to P4, subfigures IV, V, and VI represent the FGS for the same intervals. Each subfigure is a georeferenced map representing the set of hydro plants in analysis. In the EGS and FGS, existent hydro plants are depicted as circles. New hydro plants that exist only in the FGS are depicted by triangles. These maps for AE_i variation are divided in seven partitions described in a legend placed at the bottom of Fig. 5.

Fig. 5 also describes how many plants are in each group, for each map from I to VI. There is one number that represents the plants in a determined AE group in the EGS, but for the FGS there are two numbers, the first before the dash represent the plants defined as circles, the one after the dash represent the plants defined as triangles. For example, the line "< −35%" column "(IV) P1–P2" the Table entry reports that there are 41 hydro plants represented by a circle in the FGS with a AE_i percentage variation lower than −35%, besides that, there are 30 hydro plants represented by a triangle that have a AE_i percentage variation lower than −35%.

Fig. 5 (I-III) shows that during the transition from P1 to P2 (Fig. 5.I) hydro plants located in the North and Northeast subsystems have the largest reduction in the EGS. Hydro plants in the South have AE_i trends bigger than +25%. From P1 to P3 (Fig. 5.II) it is possible to notice an intensification of the phenomenon noticed in Fig. 5.I, more plants in the North and Northeast subsystems have AE_i variations lower than −35%, and more plants in the South subsystem have increases of 35% in their AE_i.

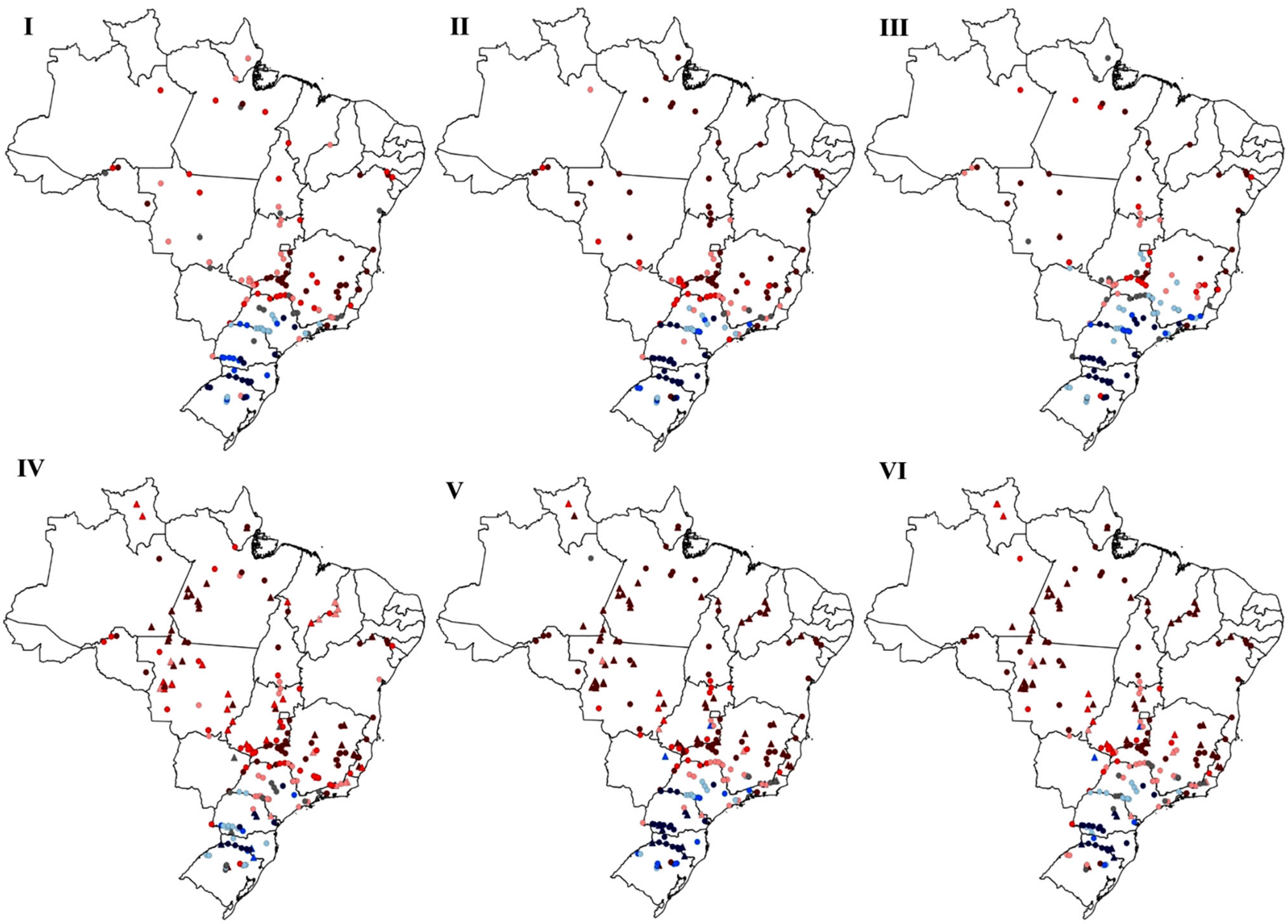
From P1 to P4 (Fig. 5.III) hydro plants in the South benefit more from climate change, with variations larger than 35% in AE_i. The opposite still happens with North and Northeast subsystems; however, some improvements are observed in these regions with plants going from "<-35%" to "-35 to −20%". In the Central-East region, some plants that were red start presenting positive AE_i variations.

The FGS has a similar behavior when compared with the EGS, however, there are other additional remarks to be considered. Many of the new plants represented in the FGS experience reduction trends in their AE_i, this is due to two facts: (1) future water inflows in the North and Northeast regions are heavily affected by changes in climate; (2) new hydro plants (located in the North) are mostly run-of-river and therefore more susceptible to variations in water inflows.

3.4. An economic perspective

To analyze potential impacts in hydropower revenues, we aim to approximately estimate monetary losses (gains) obtained by potential AE reductions (increases) for hydro plants. We consider the AE as a measure of how much would have to be discount (added) in energy portfolios available to be negotiated through selling contracts in future periods. It is beyond of the scope of this work to project electricity prices and their associated uncertainties into the future, instead, we use as our base value the long-term prices for capacity expansion plans from Ref. [34] to monetize the AE variations.

In the first quarter of each year, the Brazilian federal energy planning company (EPE) (responsible for making the planning studies for the country's energy systems) determines the expansion



AE Variation		Number of Plants- EGP			Number of Plants- FGP		
New - Old		(I) P1-P2	(II) P1-P3	(III) P1-P4	(IV) P1-P2	(V) P1-P3	(VI) P1-P4
● - ▲	<-35%	28	51	23	41 - 30	56 - 51	50 - 47
● - ▲	-35% to -20%	25	21	21	36 - 21	17 - 4	16 - 8
● - ▲	-20% to -5%	29	18	16	26 - 12	20 - 5	27 - 6
● - ▲	-5% to 5%	16	8	18	11 - 3	5 - 2	15 - 1
● - ▲	5% to 20%	15	11	26	14 - 1	11 - 1	13 - 3
● - ▲	20% to 35%	12	9	10	4 - 2	12 - 2	3 - 2
● - ▲	>35%	16	23	27	9 - 4	20 - 8	17 - 6

Fig. 5. AE percentage variation for the model Eta-20km during P1 to P2, P1 to P3, and P1 to P4, for the EGS and FGS

marginal cost of electricity (MCE). The MCE estimates the average electricity generation prices considering the current system and new projects that are planned to be deployed in the electric power system (decades ahead in the future) to satisfy increments in demand. The MCE computed in 2016 presented a value of 53.8 [US$/MWh] [34] (considering a currency exchange rate of 1 [US$] = 3.4 [R$]). This MCE is adopted, instead of trying to project electricity prices decades ahead, to evaluate potential monetary impacts on the system from P1 to P2 (Eta-20 km model).

The differences in subsystems AE from P1 to P2 were multiplied by the MCE to obtain the monetary losses (or profits) for each subsystem. For the EGS, subsystems 1, 3, and 4 presented a negative impact of at least US$3 billion, US$0.74 billion, and US$2.17 billion, respectively over the course of one year. Subsystem 2 is the only one with a positive impact of US$0.79 billion. In aggregated terms, it is expected that the whole system will bear a yearly loss of US$5.13 billion. The FGS losses are expected to be even higher, where the whole system accounts for a yearly loss of approximately US$12.2 billion. In terms of subsystem-level analysis for the FGS, subsystems 1, 3, and 4 have a negative impact of at least US$7.9 billion, US$1.63 billion, and US$3.41 billion, respectively over the course of one year. Subsystem 2 is the only one with a positive impact of US$0.76 billion. As the AE reduces for most of the other periods, the monetary loss estimates will be even higher. This can easily be computed using information from Table 2 and the MCE.

3.5. *Discussion, remarks and future research*

It should be mentioned that the climate change phenomenon, and its associated impacts on hydropower, will affect the whole power system (suppliers and demand). Consequently, this issue will potentially affect the MCE and therefore the results of this economic assessment. However, we aim to be conservative in our assumptions and consider in our calculations the current MCE, despite the fact we understand that the likelihood of higher future prices is extremely significant. As a final result, climate change impacts will be also for final consumers that will probably experience higher prices in the future due to considerable reductions in hydropower, which is one of the most competitive power generation technologies in the country to date.

In this analysis of the climate-water-energy nexus performed under different power generation system configurations, we notice significant impacts of climate change reducing hydropower production. This is more evident in the FGS and subsystem 4, where most of the planned run-of-river hydro plants will be located and the impacts in water inflows are higher. Regarding to climate models, from the analysis we notice differences between the data from Eta-20 km and Eta-40 km. This shows that a higher resolution regional climate model representation adds information to the definition of energy parameters, however, not as much as when comparing regional to global climate models as observed [17].

Our analysis is based on different premises, data and modeling choices as well as system and market regulations. Therefore, potential uncertainties in our findings are expected. For example, as mentioned earlier, uncertainty characterization and risk assessment of climate change are out of the scope of this work, however, future work could consider our procedure to evaluate energy metrics in different climate change scenarios, and then use these scenarios along with probabilities of occurrence in a robust framework to support decision-making as in Refs. [13], [14].

In this paper, several water inflow time series at each hydropower plant were used from the hydrological model MGB forced with simulated Eta information. We chose the Eta model because of its good performance to represent the climate in the region in analysis. However, information from other models could be used to perform multi-model projection as in Ref. [35] (the same could be considered for other IPCC climate change scenarios with different CO_2 emission pathways).

The HTSP runs to define AE did not consider risk-averse methodologies such as [36] and [37]. We decided to avoid including risk-averse metrics because the definition of the parameters λ (tradeoff between minimizing the expected total cost and risk aversion of high costs) and α (α -percentile of extreme costs that are to be avoided) is sensitive and is still in debate in the literature [38]. However, future work could analyze the problem from a risk-averse perspective for different configurations of λ and α values depending on the risk tolerance of an investor or from a government agency.

In addition, other work could explore different procedures to divide the system AE into individual values. For example, the ideas presented in Refs. [24], [39] and [40] could be explored to define different ways to divide the system FE among the set of hydro plants and then use those values to divide the system AE. Also, the HTSP runs to obtain the system AE are performed using an uncertainty in energy inflows and an aggregate representation of the hydro plants, another possibility would be using a single model with individual hydro plants representation and uncertainty in water inflows over different CPs to define individual values for hydro plants AEs.

Two different configurations of the Brazilian hydropower generation system were tested, the EGS and the FGS. However, the FGS is a planned configuration that is prone to revisions and changes. For different configurations, we should also expect differences in system and individual AE and FE values, but not as significant as when considering other climate models, scenarios or different methodologies.

4. Conclusion

This paper shows how climate changes scenarios can impact hydropower revenues in Brazil. According to the findings, the South region benefits from climate change (for the scenarios in analysis), with significant increases in subsystem assured energy. The same is observed for most hydro plants inside that subsystem. For the other regions of the country the future perspective is that, in most cases, changes in climate are going to impact by reducing their assured energy. Moreover, our work shows the importance of using climate information when planning power generation systems. Results for hydro plants planned to start their operation up to the year 2030 showed significant decreases in their assured energy for almost all simulated periods. While potential reductions in specific places may be hard (or impossible) to prevent, it is necessary to consider potential efforts to mitigate the negative consequences of future climate in generation systems. Some possible actions are related to hydro plants repowering for plants located in regions with favorable future climate, and investments in other sources of generation such as wind, solar, biomass and nuclear that can help system planners to design a more stable and robust generation portfolio.

Acknowledgments

The authors want to thank FAPEMIG, CNPQ and CAPES in Brazil for this work financial support. The authors want to thank APINE members for the financial support of the Strategic R&D project 010/2008-ANEEL; the authors also would like to thank other project participants (J.A. Marengo, S.C. Chow, B.C. Silva, D. Andres, L.M. Alves, W. Collischonn, J.M. Bravo, T. Baliza, T. Pietrafesa, V. Etechebere and W. Dias).

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