Techno-economic assessment of high variable renewable energy penetration in the Bolivian interconnected electric system

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ABSTRACT

Bolivia plans significant investments in conventional and renewable energy projects before 2025. Deployment of large hydro-power, wind and solar projects are foreseen in the investment agenda. However, and despite the large renewable potential in the country non-conventional renewable technologies are not yet expected to be a main source in the supply chain. The aim of this article is to evaluate the flexibility of the Bolivian power generation system in terms of energy balancing, electricity generation costs and power plants scheduling in a scenario that considers large solar and wind energy technology deployment. This is done using an open source unit commitment and optimal dispatch model (Dispa-SET) developed by the Joint Research Center of the European Commission. National data for existing infrastructure, committed and planned energy projects are used to assess the case of Bolivia. The base scenario consider all techno-economic data of the Bolivian power system up to 2016. A harmonized dataset is gathered and released as open data to allow other researchers to run and re-use the model. This model is then used to simulate scenarios with different levels of solar and wind energy deployment. Results from the analysis show that an energy mix with participation of solar and wind technology with values lower than 30% is technically feasible and indicates that further grid reinforcements are required.

1. Introduction

The International Energy Agency (IEA) projected that electricity generation based in renewable sources should increase from 3% today to more than 20% by 2040 to reduce GHG emissions, and thus reach a scenario with temperature increase below of 2ºC [1]. Likewise, the International Renewable Energy Agency (IRENA) reports the need for raising the share of renewables in the world primary energy supply up to 65% by 2050 [2]. However, variability and uncertainty of renewable energy sources represent a challenge for electrical grids.

Power systems must comprise technical resources to cope with uncertainty and variability in the demand, and supply of energy [3]. A power system is considered flexible if under economic limits, it is able to respond to large fluctuations in both the generation and the demand [4]. The insertion of Variable Renewable Energy Sources (VRES) entails additional flexibility requirements, which can be achieved by:

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-   Dispatchable power plants (i.e. with ramp up and ramp down capabilities, reserves).
-   Energy Storage systems, mainly in the form of pumped hydro storage units.
-   Grid interconnections between countries.
-   Demand side management (DSM) [5].

For example, in [6] is studied the potential of small-scale CHP plants based on natural gas to participate in energy balancing for secondary reserve control in the German power system to facilitate the integration of VRES. In [7,8] the importance of Pumped hydro storage is highlighted to accommodate of fluctuating renewable sources in order to increase the wind and PV farms integration. Furthermore, in [9], it is shown that different forms of energy storage, such as thermal, gas and liquid can increase the power systems flexibility at a competitive cost. The potential of DSM for increased VRES integration is presented in [10], with results showing a 7.2 TWh reduction in total European VRES curtailment, achieved with an 8 to 24% increase in DSM. In [11,12], the importance of adding flexible electricity demands is highlighted as key step towards a transformation of power systems into 100% renewables, especially implementing the electric vehicles technologies.

The above-mentioned studies usually evaluate only one dimension of flexibility. Nonetheless, to understand of how electric grids may react to higher penetration of VRES, a complete assessment of all four flexibility metrics pointed out above is needed. For this purpose different tools are available to evaluate the systems flexibility.

For example, the effects of wind energy in the German power grid and Midwest regions of USA are evaluated in [13,14] using the AEOLIUS and InFLEXion tools respectively. These methods need results of two separate models without direct feedback between both and can only be used to estimate flexibility provision.

Other tools, such as REFLEX, implemented in the USA Californian system [15], and the well-known TIMES model (e.g. for Portugal and Belgium in [16,17]), result in additional complexity, by incorporating stochasticity in the first case; and in the second case, by adding low-time resolution techno-economic constrains into a long-term planning model. This results in high computational load which must ultimately, be weighed against the improvement in models accuracy.

Other tools provide flexibility evaluation frameworks using only aggregated data (e.g. no time series) as the so-called Flexibility Charts [18], which measure the power systems flexibility resources through pumped hydro, hydro dams, combined heat and power units, combined cycle gas turbine and interconnections, and then compare it with the installed capacity relative to peak demand.

Some case studies were performed in South America using similar approaches. In [19] the hydro dominated Brazilian power system is evaluated using the FAST2 tool which assesses the flexibility needs by determining if a maximum change in a supply/demand balance can be meet at each time step. The study shows that the system is able to accept 20% of VRES penetration without any issue. Other cases studies in Colombia and Uruguay were carried out using the FlexTool model [20,21]. In the first case, the Colombian power system, dominated by 70% of hydro dam generation, can accept a VRES penetration as high as 30%. The results show a need to improve the transmission lines capacities mainly due the presence of "hot spots" (high generation power densities). There are also some requirements for new thermal units to compensate the possible flexibility shortages in very dry years. In the Uruguayan case, the current power system is almost 100% renewable (56% of hydro and 41% shared between wind, biomass and solar), and high quantities of curtailed energy are already reported (nearly of 22% of VRES energy produced). Results also show that new conventional thermal units should be implemented for the dry years. Because of the simplicity of the methodology, the results should however be considered with care and completed with more comprehensive analyses using detailed unit commitment and dispatch models.

In the Bolivian case, the national system operator (CNDC, Comité Nacional de Despacho de Carga) uses the PSR software to optimize power plants dispatching [22,23]. PSR is a private software whose license has a considerable cost and is out of the financial reach for academics, civil society or small companies in the country. However, it is important to note recent developments of a number of open-source energy system modeling tools, which are now comparable to commercial software in features and functionalities [24]. The open-source approach is also beneficial to the quality of science, as it increases the transparency, re-usability and reproducibility of the work [25].

As an example the Open Source Energy Modelling System, OSeMOSYS has been used in some of the recent works related to the Bolivian energy sector.

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In [26] a country level model is presented to project the future overall energy needs of Bolivia until 2035. Furthermore, [27] evaluates the influence of the weighted average cost of capital and carbon taxation on the abatement carbon emissions and its cost in the Bolivian power generation system. In [28], an analysis of the Bolivia's bargaining strength comparing to other countries (Paraguay and Peru) is carried out evaluating its possibilities to export electric energy mainly to Brazil. These studies use long-term approaches, providing frameworks which support and guide future energy policies related to Bolivian energy expansion planning. However, they do not evaluate in depth the requirements that the power sector might expect from a flexibility operative perspective.

Therefore, the aim of this work is to evaluate the flexibility of the Bolivian interconnected electric system (Not taking account off-grid systems) against a high presence of solar-PV/wind-onshore technologies. The particular characteristics of Bolivian system are taken into account, such as the great potential for solar energy [29], it should be noted that this work focuses on the operational costs of power generation, leaving aside other energy aspects such as transport or heating requirements as well as any financial profitability analysis and electric stability topics. For that propose the open-source unit commitment and optimal dispatch model Dispa-SET [30] has been selected. This tool has been developed to represent short-term operation of large scale electrical systems with a high level of details [30] which addresses the limitations of the tools described above. Dispa-SET was primarily designed to model the EU power sector [30] but was also used for more specific case studies such as Belgium [31] or France [32] to measure the flexibility of a power system dominated by nuclear generation with high penetration of wind energy.

2. The Bolivian case study

Bolivia mainly relies on natural gas as primary energy source. In 2000, natural gas represented 57% of primary energy produced, and in 2010 this percentage raised up to 80% as a consequence of significant growth in natural gas exploitation. During the period 2000-2010, non-renewable energy production increased by 208% while renewable energy generation only increased by 21% [33]. By 2016, the Bolivian primary energy production structure was constituted mainly by natural gas (81.02%), followed by condensed oil and gasoline (13.15%), traditional biomass (5.14%) hydro-energy (0.68%), and VRES (wind and solar) with 0.02% [34,35,36,37].

2.1. Power sector
In 2016 the Bolivian electric matrix was dominated by thermal generation (natural gas with 69% and diesel with 1.5%). The Bolivian electric system comprises the National Interconnected System (SIN, Sistema Interconectado Nacional) which supplies the main cities and the isolated systems (SA, Sistemas Aislados) that provide electricity to remote places.

2.1.1. Bolivian interconnected system (SIN)
The SIN consists of generation, transmission and distribution facilities operating coordinately to supply the electricity consumption of eight departments representing 96% of the national demand [38]. The Bolivian system is divided into four well-defined areas as shown in Figure 1: North (La Paz and Beni), Oriental (Santa Cruz), Central (Oruro and Cochabamba) and Sur (Potosí, Chuquisaca and Tarija). The high voltage transmission system (STI, Sistema Troncal de Interconexión) is the part of the SIN that includes 230, 115 and 69 kV transmission lines.

The SIN generation fleet is composed of:
- Hydroelectric power plants that consist of run-of-river units, reservoir plants and a power plant whose operation depends on the supply of drinking water in the city of Cochabamba.
- Thermal units composed of open-cycle natural gas turbines, steam turbines that operate with sugarcane bagasse, natural gas engines and Dual Fuel units that use natural gas and diesel oil.
- Combined cycle steam turbines that use the exhaust gases of natural gas turbines,
- Diesel engines.
- Finally, wind-onshore turbines in Qollpana central which is the only VRES capacity installed in the SIN [38].

Table 1 presents the SIN composition in 2016 dis-aggregated by zones and technologies. It reaches a total capacity of 1.9 GW with 139 units, of which 0.48 GW (26.1%) correspond to hydroelectric, 1.4 GW (70.9%) to thermal, 0.027 GW (1.4%) to wind-onshore and 0.03 GW (1.6%) correspond to biomass [38,40].
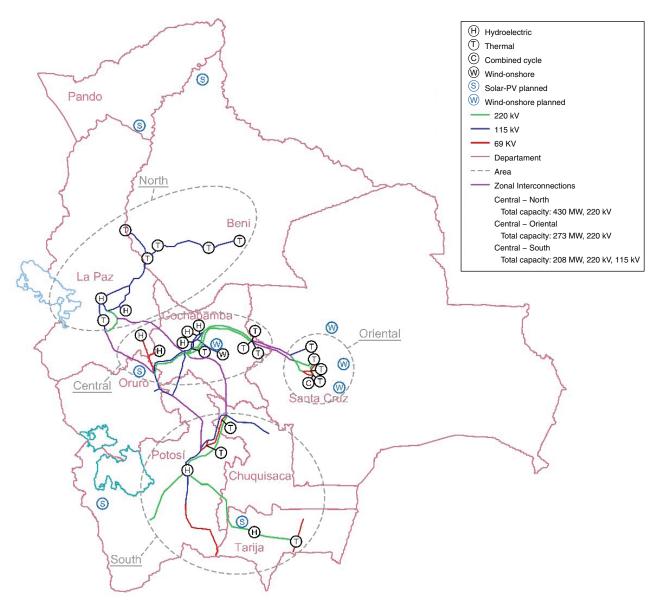
Figure 1: The SIN layout at 2016 and VRES projects planned up to 2021-2022 [38,39]

2.1.2. SIN electricity demand

The demand is divided into: Regulated consumers, mostly residential, who are served by distribution companies, and non-Regulated large consumers which are large industrial enterprises that directly participate in electricity markets [38]. The consumption is highest in the Oriental area with 37.8%, followed by North with 24.3%, Central with 21.4% and South with 17.2% [41].

The electric consumption of the country is mainly residential. In 2014 this segment demanded 38% of the required energy, followed by industrial with 27%, public services (street lighting, hospitals, public institutions, etc.) with 24% and mining sector with 11% [35].

In recent years, the demand has experienced a strong growth: In the period 2000-2006, an average growth rate of 4% was registered, reaching 4.4 TWh in 2006. In 2007-2012 the increase rate was 9% with 6.6 TWh for 2012 [41]. In 2016 the total consumption reached 8.4 TWh. For 2021, a consumption of 12.4 TWh is foreseen [38].

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Table 1: Power generation fleet in the SIN in 2016 [38,40]

Area	Central name	Technology	Number of Units	Total Power (MW)
North	Taquesi System		2	89.19
	Zongo System	Hydroelectric run-of-river	21	188.4
	Quehata		2	1.97
	Kenko	Natural gas thermal	2	17.78
	El Alto		2	46.19
	Trinidad	Oil thermal	21	28.58
	San Buenaventura	Biomass thermal	1	3
Central	Miguillas System	Waterfall hydroelectric dam	9	21.11
	Corani System		9	148.73
	Kanata	Hydroelectric dam	1	7.54
	Valle Hermoso		8	107.65
	Carrasco	Natural gas thermal	3	122.94
	Bulo Bulo		3	135.41
	Entre Rios		4	105.21
	Qollpana I & II	Wind-onshore	10	27
Oriental	Guaracachi	Gas combined cycle	3	192.92
			5	126.72
	Santa Cruz	Natural gas thermal	2	38.07
	Warnes		5	195.56
	Unagro	Biomass thermal	1	6
	Guabira		1	21
South	Yura system	Hydroelectric run-of-river	7	19.04
	San Jacinto	Hydroelectric dam	2	7.6
	Aranjuez		10	33.76
	Carachipampa	Natural gas thermal	1	13.38
	Del Sur		4	150.38

2.1.3. SIN generation capacity expansion

The political constitution of the Bolivian estate (CPE, Constitución Política del Estado) establishes that every person has right to universal and equitable access to electricity, and it is the duty of the government to provide all basic services through public, cooperatives or mixed entities [42]. Consequently, due to the high levels of demand growth and low coverage in rural areas [22], the Bolivian government proposed a SIN expansion plan (POES, Plan Óptimo de Expansión del SIN). This plan presents a vision of the development of Bolivian electric sector until 2021-2022 [22,43] with the objective to complete the electric integration of the country by 2025 through new infrastructure and a gradual integration of SA into SIN [41]. Table 2 summarizes the planned generation projects in each of the four regions [22,39,43,44].

Interconnections projects (called mega-projects), intended for energy exchange with neighboring countries were proposed and they are still in the governmental agenda. However since there is not firm schedule yet [45,46,47], the Bolivian system is considered as isolated in this work.

2.2. Renewable generation potential

The potential of VRES in Bolivia is distributed throughout the territory. Solar energy is feasible in all regions, but mainly in the Andean highlands sector. Wind energy predominates in the departments of Santa Cruz and Cochabamba and in some parts of the highlands. The geothermal sources are located southwest of the department of Potosí. Finally, important biomass resources are available in the eastern and northern part of the country [39].

Table 2: Conventional and renewable generation projects implemented and planned in the period 2016-2025 [22,39,43,44]

Area	Central name	Technology	Department	Situation	Power (MW)
North	Umapalca	Hydroelectric	La Paz	Projected up to 2021–2022	85
	Palillada			Projected up to 2021–2022	118
	San Cristobal			Projected up to 2019	17
	Anazani			Projected up to 2019	19
	Santa Rosa			Projected up to 2019	9
	Guayaramerin	Solar-PV	Pando (Cobija)	Projected up to 2021–2022	3
	Riberalta		Beni	Projected up to 2021–2022	6
Central	Entre Ríos	Gas combined cycle	Cochabamba	Projected up to 2021–2022	306
	Misicuni	Hydroelectric		In operation since 2018	120
	San Jose			Projected up to 2019	124
	Qollpana III	Wind-onshore		Projected up to 2021–2022	21
	Oruro I & II	Solar-PV	Oruro	Projected up to 2021–2022	100
Oriental	San Julian	Wind-onshore	Santa Cruz	Projected up to 2021–2022	36
	Warnes			Projected up to 2021–2022	21
	El Dorado			Projected up to 2021–2022	36
South	La Ventolera	Wind-onshore	Tarija	Projected up to 2021–2022	24
	Laguna Colorada	Geothermal	Potosi	Projected up to 2021–2022	100
	Uyuni Colchak	Solar-PV		Projected up to 2021–2022	60
	Yunchará		Tarija	In operation since 2018	5

2.2.1. Solar resources

Bolivia presents high radiation levels in all the country. Almost 97% of the territory is suitable to use energy solar as primary generation source [29], except some areas that constitute less than 3% of the territory, since they have been identified as zones of dense cloudiness. These zones correspond to the eastern ranges of the Andes, where the rate of solar radiation is very low, making their use impracticable [48]. As shown in Figure 2 [49,50], the southwest area of the country, has the highest radiation values (5.1–7.2 kWh/m^2-day), while the north-eastern zone presents lowest values (3.9–5.1 kWh/m^2-day). The variation of hours between sunrise and sunset throughout the year does not exceed one [51], therefore, the radiation rate between the winter and summer seasons does not represent exceed 25% [48]. In addition, Bolivia comprises a strip of territory which receives the largest solar radiation in the world (the tropical zone of the South, between the parallels 11° and 22°) thanks to its high altitude with respect to the sea level, whose dry climate generate lower solar dispersion [48].

2.2.2. Wind resources

Since about 25 years ago, Bolivian wind energy utilization is restricted to mechanical pumping of water
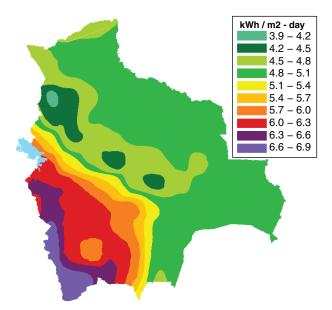

Figure 2: Horizontal global solar radiation in Bolivia (annual average) [49,50]

and small-scale power generation these projects were located in the Mennonite colonies in Santa Cruz, in Oruro, and in the Uyuni area in Potosí. They were developed by the Corporation of Development of Oruro (CORDEOR) [48]. In recent years the Bolivian wind

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atlas was developed [52] showing annual measurements of wind velocity at three different heights (20,50, 80 m). The wind resource at Bolivian territory seems to be more limited than solar, stronger resource are concentrated in five sectors: Around Santa Cruz city, mostly south and west of urban center. At southwest border between Chile, Argentina and Potosi department. On a corridor that goes from east to west between La Paz and Santa Cruz, passing through north of Cochabamba department. On a north to south corridor between Oruro and Potosi departments. And around the Titicaca Lake in La Paz department [52]. Almost all the zones mentioned above (except Santa Cruz department) are at a considerable height with respect to sea level. This diverse geographical profile and the topographic characteristics of the Bolivian territory induce a high level of wind turbulence and a reduction in the air density, which decreases the efficiency of the turbines. However as the wind speed increases, the turbulence decreases, this, together with the reduction of air density, improves the efficiency of the turbines beyond the theoretical value [53]. Nevertheless wind technology at high altitudes is a research topic that should be studied deeper.

3. Model description

The open-source Dispa-SET model focuses on the short-term operation of large-scale energy systems by solving the unit commitment and energy dispatch problem (UC/D). It considers that the system is managed by a central operator that has all the technical and economic information of each plant and the demand in each node of the transmission network [5].

The aforementioned UC/D problem is a mixed integer linear programming (MILP) implemented in GAMS [54]. The formulation is based upon publicly available modelling approaches [55,56,57]. The goal of the model

being the simulation of a large interconnected power system, a tight and compact formulation has been implemented, in order to simultaneously reduce the region where the solver searches for the solution and increase the speed at which the solver carries out that search. Tightness refers to the distance between the relaxed and integer solutions of the MILP and therefore defines the search space to be explored by the solver, while compactness is related to the amount of data to be processed by the solver and thus determines the speed at which the solver searches for the optimum [30].

It aims at minimizing the operational costs, which comprise start-up and shut-down, fixed, variable, ramping, transmission-related and load shedding costs, see Eq. (1). The demand is assumed to be inelastic to the price signal [30].

$$MinSystemCost = \sum_{u,n,i} \left\{ \begin{array}{c} CostStartUp_{u,i} + CostShutDown_{u,i} + \\ CostFixed_u \cdot Committed_{u,i} + \\ CostVariable_{u,i} \cdot Power_{u,i} + \\ CostRampUp_{u,i} + CostRampDown_{u,i} + \\ PriceTransimission_{i,l} \cdot Flow_{i,l} + \\ \sum_n \left(CostLoadShedding_{i,n} \cdot ShedLoad_{i,n} \right) \\ VOLL_{Power} \cdot \sum_n \left(LostLoadMaxPower_{i,n} + LostLoadMinPower_{i,n} \right) + \\ VOLL_{Reserve} \cdot \left(LostLoadReserve2U_{i,n} + LostLoadReserve2D_{i,n} \right) + \\ VOLL_{Ramp} \cdot \left(LostLoadRampUp_{u,i} + LostLoadRampDown_{u,i} \right) \end{array} \right\}$$

(1)

Since the simulation is performed for a whole year with a time step of one hour, the problem dimensions are not computationally tractable if the whole time horizon is optimized. Therefore, the problem is divided into smaller optimization problems that are run recursively throughout the year. Figure 3 shows an example of such approach, in which the optimization horizon is one day, with a look-ahead (or overlap) period of one day. The initial values of the optimization for day j are the final values of the optimization of the previous day. The look-ahead period is modelled to avoid issues linked to the end of the optimization period such as emptying the
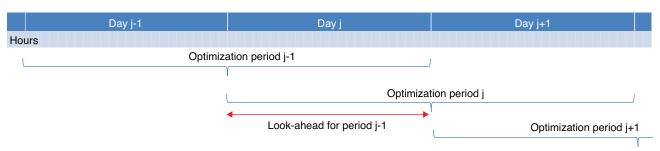

Figure 3: Time horizons of the optimization with look-ahead period [30]

hydro reservoirs, or starting low cost but non-flexible power plants. In this case, the optimization is performed over 48 hours, but only the first 24 hours are conserved [58].

Although the previous example corresponds to an optimization horizon and an overlap of one day, these two values can be adjusted by the user. As a rule of thumb, the optimization horizon plus the overlap period should be as least twice the maximum duration of the time-dependent constraints (e.g. the minimum up and down times). In terms of computational efficiency, small power systems can be simulated with longer optimization horizons, while larger systems should reduce this horizon, the minimum being one day [59]. For the present work, an optimization horizon of four days and an overlap period of one day was used.

A detailed description of the model and its constraints can be found in [60] but its main characteristics can be summarized as follows:

- Minimum and maximum power for each unit
- Power plant ramping limits
- Reserves up and down
- Minimum up/down times
- Load Shedding
- Curtailment
- Pumped-hydro storage
- Non-dispatchable units (e.g. wind turbines, run-of-river, etc.)
- Start-up, ramping and no-load costs
- Multi-nodes with capacity constraints on the lines (congestion)
- Constraints on the targets for renewables and/or CO_2 emissions
- Yearly schedules for the outages (forced and planned) of each units [31].

For other hand, due to The Dispa-SET project is relatively recent, and current version does not evaluate following aspects:
- Grid constraints (DC power-flow).
- Stochastic scenarios.
- Modelling of investment and capacity expansion.
- Modeling of the ancillary markets.
- Mid-term hydro scheduling [59].

Probably the main drawback found is that the tool does not have a defined graphic interface as other commercial software, however it does not should mean a big problem to advanced students or researchers.

3.1. Input data
The model is data-intensive and requires a number of times series, cost data and power plant data. It should be noted that some time series are obtained from interpolating available data (weekly or daily). For the case of specific technical data, some information was restricted from pertinent national entities so references data available in the bibliography are assumed. These are described in the next sub-sections.

3.1.1. Power plants data
Specific techno-economic data must be provided for every power plant installed in the system. The common technical data includes the type of power plants (technology), the area where the unit is located (Zone) and the power capacity. This information is specified in tables 1 and 2 above.

Specific technical data sources comprise fuel type and prices, extracted from [22,43], (it should be noted that the biomass price is assumed to be zero since to cane bagasse waste is used by sugar companies to generate electricity) efficiency [61], CO_2 emission factors (CO_2 intensity) [62], minimum load [19,61,63], ramp up/down [32,61,64], start up time [19,61] and minimum up/down times [61]. Specific data for storage units (storage capacity and efficiency) are found in [65]. It should be noted that the CO_2 emission input does not impact the results since no CO_2 pricing scheme is available in the current Bolivian regulation. A null price of CO_2 emission is therefore assumed.

Economic data refers to the costs incurred by the units when they come into operation, i.e.: fixed cost (no load cost) related of operation and maintenance of units, extracted from [61,66], start-up cost (fuel cost for start-up, auxiliary electricity, chemical products, extra workforce etc.) from [61] and ramping cost (these values are in general relatively low compared to start-up values, still they can be relevant for generation technologies which are designed for baseload applications) from [67]. These two last cost parameters, also called cycling cost, turn important for thermal units [61], since the on/off number and ramping changes of this technologies increasing in response to

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Table 3: Techno-economic data input for the model

| Technology | Fuel cost (€/MWh) | | Efficiency (%) | CO_2 intensity (TCO$_2$/MWh) | Minimum load (%) | Ramp up/down rate (%/min) | Start-up time (h) |
	Subsidized	Non subsidized					
Natural gas thermal	3.55	19.39	35.54	0.7	20	15.42	1
Oil thermal	13.92	77.31	35.54	0.7	20	15.42	1
Natural gas combined cycle	3.55	19.39	55.93	0.37	15	6.42	5
Biomass thermal			35.54		20	15.42	1
Hydroelectric			93.39			9	0.6
Wind-onshore						3.33	
Solar-PV						3.33	
Geothermal			50		10	7	2

Table 4: Techno-economic data input for the model (continuation)

| Technology | Minimum up/down time (h) | Total storage capacity (GWh) | | No load cost (€/MW/h) | Star-up cost (€/MW) | Ramping cost (€/MW) |
		2016	2021			
Natural gas thermal	1			1.88	77	0.8
Oil thermal	1			1.88	77	0.8
Natural gas combined cycle	4			1.94	75.95	0.5
Biomass thermal	1			1.88	77	0.8
Hydroelectric		587.18	994.87	5.48		
Wind-onshore				3.98		
Solar-PV				2.36		
Geothermal				6.16		

fluctuations in system load/supply requirement due to the VRES penetration [68]. A summary of the input data is presented in Table 3 and Table 4, classified by technology type.

3.1.2. Load time series
The times series are provided for the whole year with a time resolution of one hour. Since there are four zones in the model, four load curves are required, aggregatedthe demands of all sectors described above (residential, industrial, public, mining). They are extracted from [69]. Figure 4 shows these load curves for the day with the highest demand (April 19 of 2016). Central, North and South zones present their peak consumption between 8:00 and 9:00 PM, while Oriental zone has two peaks, at 3:00 and 8:00 PM. On the other hand the valley hours (minimum demand) occur near to 5:00 AM for all zones.

3.1.3. VRES Availability Factors
Availability factor is defined as the ratio between the instantaneous renewable generation and the installed nameplate capacity. Three time series are required: solar-PV, wind-onshore, and hydroelectric run-of-river [30]. Solar resources availability factor time series are obtained from global horizontal radiation models using approximate geographic location [70], environmental features [71,72], PV systems technical features [73,74,75], and monthly average solar radiation data of Bolivian solar map and data extracted from [76].

Figure 5 shows the availability factor profile of the five PV centrals in January. The high altitude locations (Uyuni-Colchak, Oruro I & II, Yunchará) have higher availability factors between September and April because of higher radiation levels in this season. High variability is also observed in December and January because of the rain season.
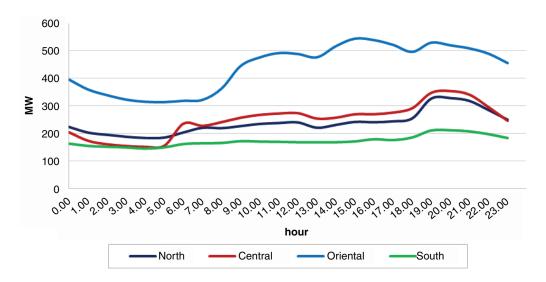
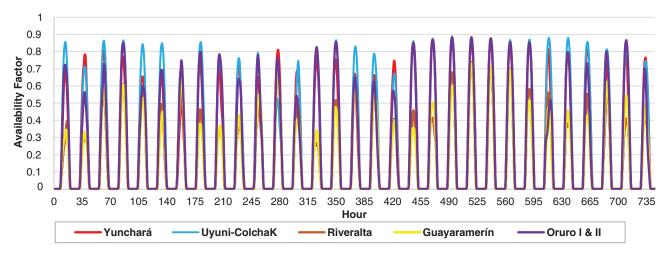Figure 4: Peak of the Bolivian electric load curves on 19th of April of 2016

Figure 5: Solar-PV availability factor time series in January of 2016 for the considered PV locations

Wind resources availability factors are generated using wind hourly velocity from [76] and approximate geographic location and technical features of both installed and planned wind turbines from [52,77,78,79]. Figure 6 displays the availability factor profile of the five wind farms in October. Centrals of Oriental zone (El Dorado, San Julian, Warnes) have a very similar profile and present high wind resources and higher peaks in February, April, July, August and October. On the other hand, and centrals of South Central zones (La Ventolera, Qollpana) are less variable but they have lower wind resource.

Hydro run-of-river resources availability factor are obtained from interpolating average daily flows [80], unit technical data as nominal power, turbine type, efficiency and height of fall were taken from [43,81]. An individual availability factor distribution corresponding to each one of run-of-river units of the SIN is used (Boticaja, Coticucho, Chururaqui, Yanacachi Huaji, Quehata, Harca, Cahua, Santa Isabel, Kilpani, Sainani, Choquetanga, Carabuco, Punutuma, Landara y Kanta). However,in Figure 7 it presents an average profile of all them, it can be seen a higher resource from December to February because of the rainy season.

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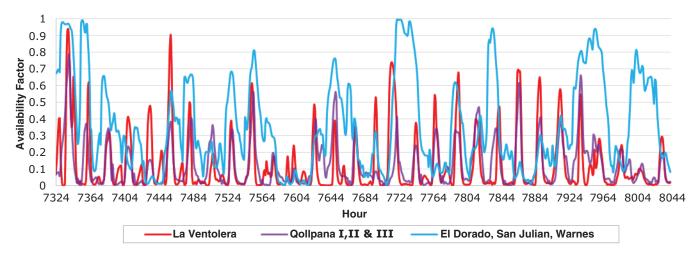
Figure 6: Wind availability factor time series in October of 2016 for all wind-onshore centrals planed by the POES
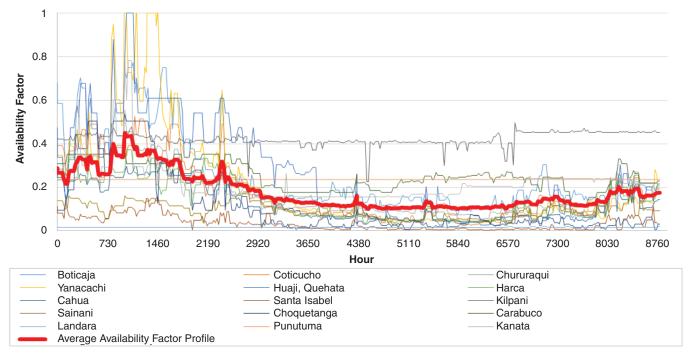

Figure 7: Hydro availability factor time series as average of all hydroelectric run-of-river units at the SIN in 2016

3.1.4. Hydro time series

Hydro storage is characterized by two time series: inflows and storage level.

The "scaled inflows" are defined as exogenous time series for each energy storage unit and are expressed as a fraction of the nominal power of this unit [30]. They are obtained from [82]. An Individual time series corresponding to each reservoir of the SIN is used in all simulation (Corani, Zongo, Tiquimani, Miguillas, Angosutura, Chojlla, San Jacinto and Misicuni). Figure 8 shows an average scaled profile from all of them and it can be seen that higher values happen during the rainy season, (December to February) and lower in winter (June to September).

Because the optimization is performed with a rolling horizon [30] of a few days, long-term storage levels must be provided as an exogenous input. In the contrary case, each optimization would tend to empty the reservoirs to
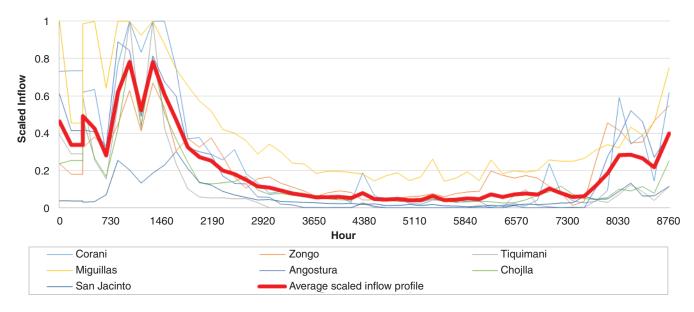
Figure 8: Scaled inflows time series as average of all reservoirs for the SIN reservoirs in 2016
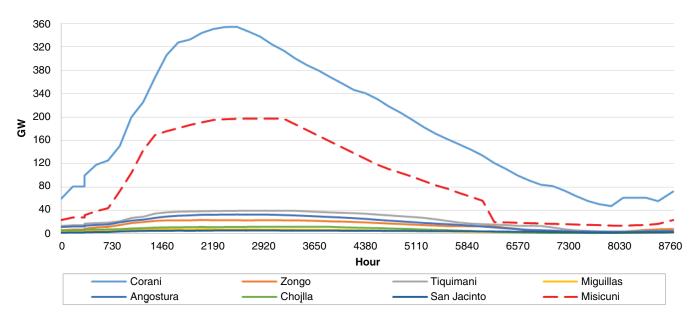

Figure 9: Stored energy evolution in Bolivian reservoirs throughout 2016

their minimum value. Historical volumes accumulated in the reservoirs are therefore imposed as a lower boundary at the end of each optimization horizon. They are expressed as a fraction of the maximum energy that can be storage in the reservoir [30]. These time series are obtained based on the weekly averages collected from [82]; and are shown in Figure 9. In 2016 the main reservoir was Corani and, from 2017, the new Misicuni hydro dam was put into operation, adding an important reservoir capacity. The lower capacity of others is explained by the fact that they were the first to be installed and just were built to supply the low demand of certain towns.

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3.1.5. Outage time series

Outages factor refers to scheduled and unplanned interruptions of generation units and varies from 0 (no outage) to 1 (total outage). The available power is therefore given by the nominal capacity multiplied by (1 – outage factor) [30]. Historical average unavailability of the SIN is 4% [22], and the POES takes 7% for thermal units and 4% for hydro units [22,43]. In this work for practical reasons, a constant value of 7% is assumed for all units.

3.1.6. Grid data

Because of the relative simplicity of the grid in Bolivia, the country is divided in four zones whose cross-border flows are limited by a net transfer capacity (no DC power flow is implemented in the current version of the model). The maximum capacity of transmission lines are obtained from [22,41,43]. Figure 1 provides the total nominal values of each interconnector; the maximum flow registered in 2016 was 264.45 MW from Central to Oriental area [83].

3.2. Scenarios

Knowing the current (2016) and future (until 2021) generation park of the SIN, different scenarios are proposed to assess the Bolivian electric system flexibility under different shares of VRES. All scenarios are evaluated into two prices of natural gas: the subsidized price by Bolivian government, 1.26 €/MMBtu and the opportunity price, i.e. the monetary value at which Bolivian gas is exported, 6.07 €/MMBtu [22,43].

3.2.1. 2016 scenario

This is the reference scenario where all data compiled up to 2016 is used. The power generation fleet is strongly dominated by conventional technologies (thermal and hydroelectric) with a very small percentage of wind-onshore generation and no solar-PV. The total installed power capacity is 1.86 GW, of which 1.34 GW (72.5%) corresponds to thermal units (gas and oil open cycle turbines and gas combined cycle turbines), 0.48 GW (26.1%) correspond to hydroelectric units (run-of-river and hydro dams), and only 0.027 GW (1.5%) of wind-onshore capacity. The total demand reached in this year is 8377.8 GWh with a maximum peak of 1.42 GW.

3.2.2. 2021 scenarios

In 2021 a total power consumptions of 12421 GWh is expected [38] and the generation capacities are increased: the total installed capacity raises to 3.11 GW, of which

1.66 GW (53.88%) are thermal, 0.98 GW (31.81%) are Hydroelectric, wind-onshore capacity grows up to 0.16 GW (5.38%), solar-PV appears with 0.18 GW (5.67%) and a 0.1 GW geothermal is installed (3.26%). The grid is also upgraded with a new 0.14 GW line between Central and North [22], a 0.16 GW line between Central and Oriental, a 0.16 GW line between Central and South and a 0.32 GW lines between Oriental and South [41]. Based on this context, different scenarios with different levels of VRES penetration are defined. First, solar-PV penetration is varied: the power of all PV parks are increased to reach 10%, 20%, 25%, and 40% of all installed capacity. Then, the same is done for wind-onshore penetration. Finally, combined solar-PV/wind-onshore penetration scenarios are simulated increasing the power of both technologies proportionally so that the VRES capacity reaches 10%, 20%, 30%, 40%, and 50% of the total installed capacity. Total power values of solar-PV and wind-onshore technologies for all scenarios are specified in Table 5. The capacities of other technologies are kept unchanged. The current location of VRES units are conserved and the hypothetical solar-PV plant is added in the oriental zone. The time series of 2016 scenario are conserved for the 2021 simulations and are up scaled when necessary.

4. Results

Table 5 highlights the main simulation results. In the results dispatch plots for 2016 (Figure 10) it can be seen that the current Bolivian generation park is clearly dominated by conventional technologies mainly thermal. High energy flows towards the North zone are stated (FlowIn and FlowOut variables) especially at lower consumption hours. This is explained by the presence of smaller units in the North zone, which cycle more effectively and at lower cost and the high start-up cost units in the other zones. The system capacity margin is sufficient in the 2016 simulation, as the demand is met at all time steps.

In the 2021 simulations, load shedding events are simulated, mostly occurring in the Oriental area at peak night hours in April. This due to an insufficient installed capacity in the area compared to the expected load in 2021. Load shedding however disappears at high penetration of wind-onshore and solar-PV, since they contribute to cover the afternoon peak. The remaining load is supplied by solar-PV energy imported from Central and South areas, as shown in Figure 11. To ensure a proper system adequacy, additional simulations are

Table 5: Main results of all SIN scenarios

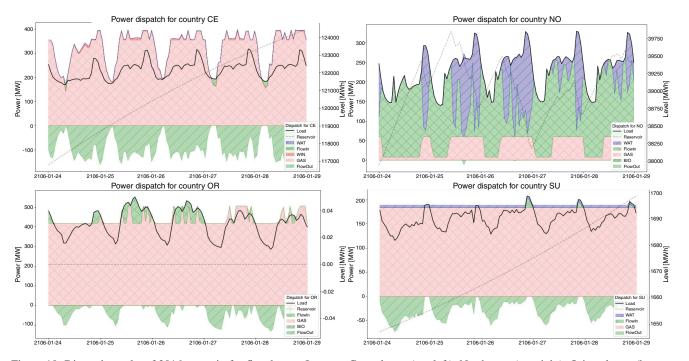| Scenarios | VRES capacity share | Installed capacity (MW) | | | Total load shedding (MWh) | VRES' energy curtailed share | Renewables' Load covered share | Total CO_2 emissions (Mt CO_2) | Total hours of congestion (h) | Average electricity cost (€/MWh) | |
		Solar-PV	Wind-onshore	Total						Subsidized gas natural price	Opportunity gas natural price
2016			27	1855	0	0%	11%	4.85	0	10.6	45.6
2021		174	165	3066	60	0%	31%	4.66	8984	7.4	31.7
2021 Solar-PV penetration	10%	322		3214	28	0%	33%	4.48	9041	7.2	30.6
	20%	724		3615	31	0%	39%	3.99	9195	6.4	27.4
	25%	964	165	3856	33	0%	43%	3.72	9172	6.0	25.7
	30%	1240		4132	40	1%	46%	3.48	9204	5.6	24.0
	40%	1929		4820	33	15%	52%	3.13	9442	5.0	21.6
2021 wind-onshore penetration	10%		322	3223	12	0%	34%	4.42	9031	7.0	30.2
	20%		725	3626	2	0%	41%	3.85	9259	6.2	26.7
	25%	174	968	3868	2	0%	45%	3.52	9322	5.7	24.3
	30%		1244	4144	13	0%	49%	3.18	9370	5.2	22.2
	40%		1934	4835	0	5%	59%	2.50	9351	4.1	17.6
2021 Solar-PV and wind-onshore penetration	10%	234	165	3126	31	0%	32%	4.58	9042	7.3	31.3
	20%	341	341	3409	0	0%	37%	4.19	9151	6.7	28.8
	30%	584	584	3895	0	0%	44%	3.66	9616	5.8	24.7
	40%	909	909	4546	0	2%	54%	2.88	9575	4.7	20.1
	50%	1364	1364	5455	6	13%	63%	2.24	9706	3.8	15.8

Figure 10: Dispatch results of 2016 scenario for five days at January; Central area (top left), North area (top right), Oriental area (bottom left) and South area (bottom right)
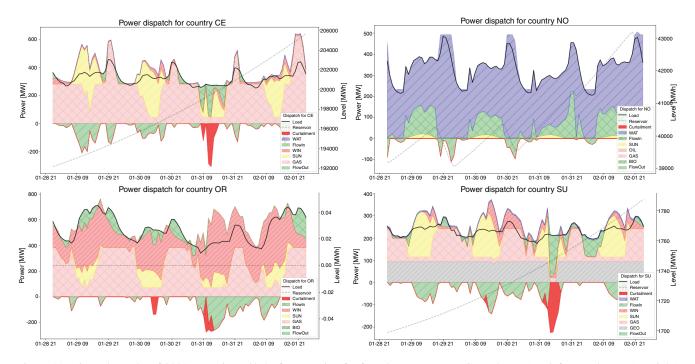
Figure 11: Dispatch results of 2021 scenario at 40% of penetration for four days at January; Central area (top left), North area (top right), Oriental area (bottom left) and South area (bottom right)

run with an additional hypothetical thermal or hydroelectric unit of 50 MW added to Oriental. The simulation results indicate that this is sufficient to suppress all probable load shedding events in all the 2021 scenarios.

The SIN expansion projects price higher-than-expected flexibility, which allows increasing VRES penetration, i.e. 724 MW of solar-PV or 968 MW of wind-onshore or a total combined power of 1160 MW. Higher values result in important amounts of energy curtailed, e.g. 64 GWh are wasted for 40% of solar-PV/ wind-onshore penetration (Table 5). Figure 11 illustrates the curtailment as the red area of the dispatch plot.

The main system limitation lies in the interconnection lines capacity since most of them are congested practically all year, despite the grid reinforcement projects. The number of congestion hours grows with the VRES penetration especially for the Central-Oriental interconnection because of the wind oversupply in the Oriental zone during lower demand hours. The opposite happens at peak night hours since the lack of capacity in the Oriental zone has to be covered by importations from the Central zone. Additional simulations indicate that, to avoid this problem, the Central-Oriental, Central-South and Oriental-South interconnections

should increase up to 975 MW, 470 MW and 510 MW, respectively.

Results in table 5 also show the change in thermal technologies generation: a considerable amount of energy from thermal units is replaced by renewable energy. This is also visible in Figure 12, e.g. by comparing the energy produced by natural gas and oil between 2016 (91%) and 2021 (69%). With additional VRES capacity (e.g. 30%), this is further reduced to 55%. In this last scenario, 1.1 Mt of CO_2 are avoided, which corresponds to a share of 23%.

Dispatching results indicate a certain complementarity between hydro wind and solar resources. This can be seen graphically in Figure 13: during the three first months of the year and part of December, there is an abundance of the water resource that coincides with large radiation levels which could produce large amounts of curtailment energy. This is however attenuated by cloudiness due to the rain season. Conversely, in the winter season with lower radiation levels and water flows reductions (decreasing of hydro-storage consequently), an increase of wind production is observed.

High levels of VRES also affect the average operational cost of energy generation, because of the higher proportion of zero marginal cost units in the system. It is
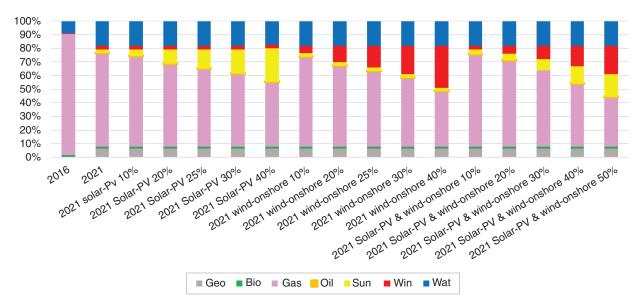
Figure 12: Production by fuel type as a fraction of total energy generated for all scenarios
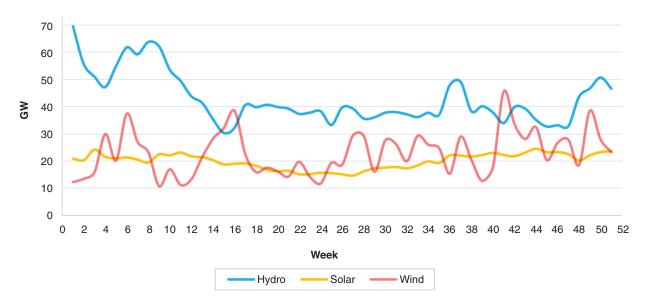
Figure 13: Weekly energy production (MWh) by renewable source type for 2021 scenario at 30% of VRES penetration

important to note that investment costs are not taken into account in these number. Table 5 also shows that the effect of natural gas prices is significant: the current subsidized price lead to very low average generation costs per kWh, which might hamper the profitability of renewable generation units in such a system.

5. Discussion and conclusions

In this work, a power system model of the Bolivian system (focused on electricity generation) was developed out using the Dispa-SET open source tool. A significant effort was dedicated to the gathering and the harmonization of a reference dataset relative to two

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different years (2016 and 2021). Such a dataset did not exist for Bolivia and is now readily usable for various types of simulations and scenarios. The whole model and the input data are released as open-source, thus ensuring a proper reproducibility and re-usability of this work [25] https://github.com/CIE-UMSS/Dispa-SET_Bolivia.

The study carried out shows that Bolivian electric system flexibility depends mainly on the response capacity of its conventional units (mostly gas thermal, and hydro-storage), and on the interconnections between its internal areas (North, Central, Oriental, and South). Others flexibility sources such as DSM or cross-sectoral coupling (e.g. thermal storage, electrical vehicles, etc.) were not considered since they are not planned for implementation in the short-term. This aspects are left for future works simulating longer-term scenarios for the Bolivian power system.

The system capability on ramping response and reserves (spinning/non spinning) together with sources of hydro-storage and the capacity of interconnections between zones are sufficient to cover the flexibility requirements by VRES and avoid any probable load shedding event.

However, one key limitation is the congestion in transmission lines between the four considered zones; as VRES penetration increases, the number of congestion hours increases. This becomes critical for 2021 because of most of lines are congested during the largest part of the year.

Simulation results show that the power system in 2021 could integrate much higher renewable energy shares than usually believed. The system has enough flexible resources to accept between 25-30% of VRES energy, which corresponds to about 964-1240 MW of solar-PV or 968-1244 MW of wind-onshore capacity.

The environmental benefits of a larger VRES capacity installed in the Bolivian electricity system are considerable: around 23% of total CO_2 emissions could be avoided only by increasing the share of renewables and without any further system adaptation required.

An average unavailability value of 7% was used to run all scenarios, nevertheless, by 2021 it is observed a system reserve margin of only 13%. The load shedding events can occur due to a coincidence in the decrease of VRES production and the increase of the load in peak hours, this makes the system susceptible to higher percentages of unavailability, so it is important to incorporate new projects of conventional generation; as the Rositas hydroelectric mega-project in the eastern area

of the SIN, which is planned with a capacity of at least 400 MW [22].

The Bolivian wind atlas shows for example that there are other potential zones to exploit wind generation, such as Titicaca lake shores at northeast of La Paz which open the possibility to develop winnd energy even more. However most of these areas are at a considerable height on sea level, and additional studies are needed to evaluate the technical feasibility of wind farms and achieve good parks planning.

There is some complementarity between renewable resources (wind, solar and water): curtailment levels are decreased if a balanced capacity between wind-onshore and solar-PV is installed. Seasonal variations are also attenuated: from December to March there is a high water availability, and the wind production peak is around January and February, which corresponds to the period of lowest PV generation.

Renewable sources tends to lower the marginal prices of electricity generation, but in the Bolivian case this reduction remains limited, as a reduction of only 1.9€ is achieved due to the natural gas subsidized price. Using the natural gas opportunity price shows a greater influence of renewable technologies on the operational costs, since a reduction of approximately 8.1€ is achieved. However, despite this, operating costs quadrupled, which would significantly affect the electricity tariffs and consequently the end user. Investment costs are not taken into account and might turn out to be prohibitive compared to extremely low cost of the electricity produced from (subsidized) natural gas sources [84,85] since subsidy only benefits the thermal plants at the expense of projects with renewable sources.

It should finally be noted that, historical VRES data from year 2016 have been used in the different proposed scenarios in a deterministic way. To obtain more accurate results, uncertainty and forecasting errors should be taken into account [86,87], e.g. for the sizing of reserves. If relevant stochastic renewable generation and demand time series can be found, the proposed model is suitable to run probabilistic simulations, which is required to better quantify the adequacy of the system.

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