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Future scenarios of variable renewable energies and flexibility requirements for thermal power plants in China

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Abstract

In 2017 about 37% of the world's wind turbines and 50% of the world's photovoltaic (PV) panels are installed in China. But at the same time a huge amount of wind power and PV power is wasted mainly because of insufficient flexibility of thermal power which is the dominant source in China's electricity system. This paper aims to assess the flexibility requirements for thermal power plants to accommodate large-scale variable renewable energies (VREs). This paper constructs three scenarios for the reference year of 2030, where VREs account for 16%, 19% and 22% in the electricity system respectively, and simulates corresponding residual load time series (residual load = load − hydropower − nuclear power − wind power − PV power). We find that the current 1%/min ramp rate of thermal power plants is basically sufficient to deal with ramps in residual load in the future. But the current 60% minimum load level of thermal power plants has to be improved to 40% or even 30%, otherwise the economic losses of VREs curtailment will be as high as $947.2 \times 10^8 - 1632.0 \times 10^8$ CNY per year in the future. It is necessary and beneficial for the central authority to invest in retrofitting the existing huge thermal power plants to improve their minimum load level.

Keywords: Operational flexibility; VREs integration; power modeling; residual load; curtailment algorithm; minimum load level.

1. Introduction

Low carbon transition has become a trend in the world. Many countries have set ambitious targets with regard to decarbonizing their energy systems. For example, European Union (EU) countries have agreed that by 2030 at least 27% of final energy consumption will be from renewable sources in the EU as a whole [1]. For China, it has promised to increase the share of non-fossil fuels as part of its primary energy consumption to 20% by 2030 [2]

These renewable targets mean in the future a large part of energy use will come from VREs. VRE is a renewable energy source that is non-dispatchable due to its fluctuating nature as opposed to a controllable renewable energy source such as hydropower. In this paper VREs specifically refer to wind energy and solar PV energy. The penetration of VREs induces integration problems. In future generation portfolios with high VREs, thermal power plants will subject to frequent ramping and start-up/shut-down [3], which induces thermal damage and shortens the lifetime of power plants. As the inherent uncertainty

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of VREs, an increased size of reserve is required to maintain short-term balance between power generation and load [4]. Also, the penetration of VREs may lead to a redesign of electricity market to provide sufficient incentives for generators performing in a flexible manner [5]. Besides, the expansion of current transmission network is required to balance VREs generation over large areas [6, 7]. Overall, the increasing VREs impose new requirements for the system flexibility.

It is thus important to understand the relationship between increasing VREs and increased flexibility requirements. Several metrics were proposed to quantity flexibility requirements [8, 9]. Some researches have been done on describing the flexibility requirements for specific countries or regions. For example, Shaker, et al. [10] analyzed characteristics of net load of California's power system from the perspectives of average daily shapes, duration curves, volatility and hourly ramps. Similarly, Deetjen et al. [11] studied how wind power and solar power impact flexibility requirements of Texas's grid based on the ramp and volatility of net load. Huber, et al. [12] measured ramp magnitude and ramp frequency across Europe and pointed that ramping flexibility needed in the future are mainly determined by the penetration of VREs, their mix and the geographic system size. In these researches flexibility requirements are usually assessed using statistical analysis of VREs generation time series and residual load (or net load) time series. Actually, the residual load (or net load) time series has been the basis for other researches related to VREs integration such as economic dispatch and unit commitment [13, 14].

In China, thermal power is the dominant source in the electricity system, providing about 70% of electricity demand. But about 90% of thermal generation is from coal-generation. Currently, the insufficient flexibility of coal-fired power plants has limited the accommodation of VREs. This paper aims to assess the flexibility requirements for thermal power plants to accommodate large-scale VREs. This paper constructs three scenarios for the reference year of 2030, with 16% VREs in S1, 19%

VREs in S2 and 22% VREs in S3, and simulates corresponding residual load time series (residual load = load − hydropower − nuclear power − wind power − PV power). This paper can be classified as literatures quantifying flexibility requirements. But the difference from previous studies is that we specifically associate residual load time series with flexibility parameters of thermal power plants. We seek to answer in the future whether the current ramp ability of thermal power plants is sufficient to follow ramps in residual load, and what is the requirement for the minimum load level of thermal power plants to accommodate VREs. The assessment of ramp rate of thermal power plants is based on analysis of ramp magnitude and ramp frequency of residual load. To estimate the requirement of minimum load level, we propose a curtailment algorithm which can calculate the amount of curtailed VREs under a given minimum load level based on residual load. The major contributions of this paper is that we show that the current ramp ability of thermal power plants is basically sufficient to deal with ramps of residual load in the future, and we calculate curtailment rates and economic losses under different minimum load levels in the future, which is useful for the policy-maker. To the best of our knowledge, it is the first time to estimate flexibility requirements of thermal power plants with large-scale VREs in the electricity system in China.

The rest of this paper is organized as follows: section 2 projects three scenarios for the year of 2030 and constructs corresponding residual load time series; section 3 introduces flexibility parameters of thermal power plants and presents curtailment algorithm; section 4 shows the main results of this paper; section 5 gives conclusions.

2. Scenarios

This section constructs three scenarios (see Table 1) and simulates corresponding residual load time series. Residual load = load − hydropower − nuclear power − wind power − PV power. We set 448 GW wind and 352 GW solar PV in S1 as predicted in [15], 448 GW wind and 552 GW solar PV in S2, and 548 GW wind

	Current	S1	S2	S3
Wind	164, 0.31	448, 1.01	448, 1.01	548, 1.24
Solar	130, 0.12	352, 0.47	552, 0.73	552, 0.73
Hydro	314, 1.19		400, 1.42	
Nuclear	36, 0.25		136, 0.97	
Thermal	1106, 4.55	1106, 5.13	1106, 4.87	1106, 4.64
Demand	6.42 PWh		by 2030: 9 PWh	

Table 1: Current status [16] and future scenarios for the year of 2030 (the left figures are capacities in GW and the right figures are annual generation in PWh, 1 PWh = 10^{12} kWh). Both hydropower and nuclear power in S1, S2 and S3 are assumed to be the same.

Figure 2: Wind power curve (cut-in speed: 3 m/s, cut-off speed: 25 m/s, rated speed: 11 m/s).
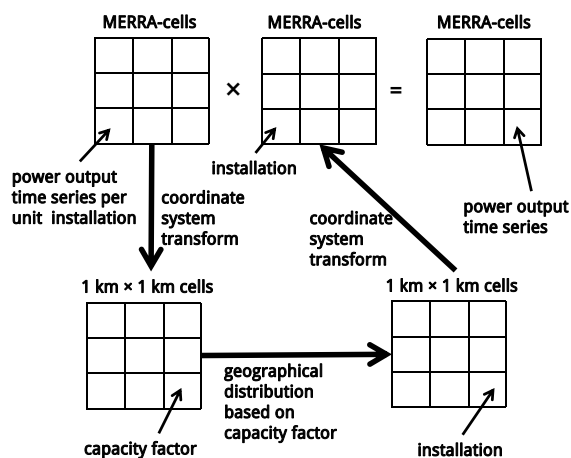

Figure 1: Calculation of VREs generation time series in each MERRA-cell.

and 552 GW solar PV in S3. Based on the national plan [2], we project that hydropower will be 400 GW, nuclear power will be 136 GW, and thermal power will be unchanged. The capacities of hydropower, nuclear power and thermal power are the same in S1, S2 and S3.

2.1. Simulation of VREs generation

The simulation of VREs generation time series is based on NASA's reanalysis data MERRA-2 (https://gmao.gsfc.nasa.gov/reanalysis/MERRA-2) which provides wind speeds and solar irradiation data at 1 hour temporal resolution and 0.5° lat × 0.625° lon spatial resolution [17]. This includes two parts: one is to calculate the power output time series per unit inst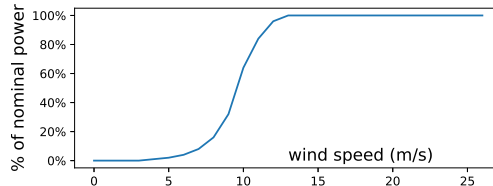allation in each MERRA-cell, the other is to distribute installations of wind and solar PV in each MERRA-cell. The process is illustrated in Fig. 1.

2.1.1. Power modeling

We model wind power output and PV power output time series per unit installation in each MERRA-cell. This paper focuses on onshore wind, as offshore wind takes a tiny fraction currently and its future is full of uncertainty. The hub height is set at 80 m in this paper. Wind speed at 80 m height is extrapolated from wind speeds at heights of 2 m, 10 m and 50 m provided by MERRA-2 using the logarithm profile law [18]. Although there are different types of wind turbines, their power curves are usually similar. The power curve used in this paper is shown in Fig. 2. Using this power curve the wind power output time series per unit installation in each MERRA-cell can be obtained, as well as the capacity factors (generation over one year normalized by installed capacity). The PV system in this paper is assumed to be of fixed horizontal system. The process to obtain PV power output includes two steps: first converts irradiance on ground provided by MERRA-2 into irradiance on PV panel; then converts panel irradiance into PV power. It is realized by using the toolbox of PVLIB [19]. Therefore, the PV power output time series per unit installation and capacity factor in each MERRA-cell can be obtained.

2.1.2. Distribution of installations

The next step is to determine installations of wind and solar PV in each MERRA-cell for the year of
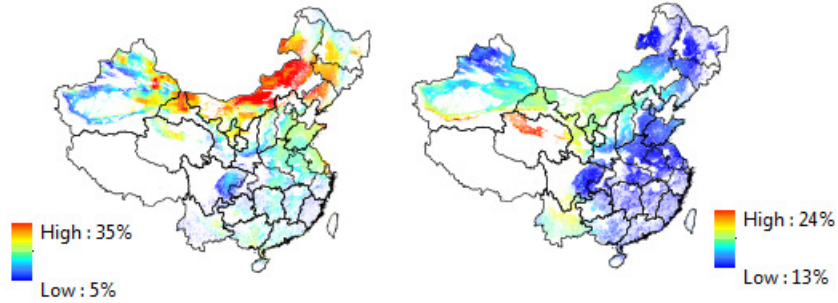
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Figure 3: Capacity factors of wind (the left) and solar PV (the right) in mainland China. Capacity factor is generation of wind or PV normalized by installed capacity. White areas are excluded land which are unsuitable for wind farms or PV stations construction.

2030. To begin with, lands which are not suitable to install wind and PV are eliminated. These are 1) protected land, data provided by RESDC (Chinese Academy of Sciences http://www.resdc.cn); 2) shifting sandy land and semi-shifting sandy land, data provided by Cold and Arid Regions Sciences Data Center in Lanzhou (http://westdc.westgis.ac.cn); 3) forest, water body, wetland and man-made built-up, data provided by RESDC; and 4) land with elevation more than 3000 m, data provided by Cold and Arid Regions Sciences Data Center in Lanzhou. Besides, the slope constraints are set at 20% for wind and 5% for solar PV [7], using slope data provided by Cold and Arid Regions Sciences Data Center in Lanzhou. The land resolution is 1 km × 1 km. Secondly, we scale up current installations of wind and solar PV in each province to future scenarios (see Table 1), that is, we assume shares of each province in wind and solar PV respectively are unchanged in the future. Data about current provincial installations of wind and solar PV are taken from [20, 21]. In reality installations are usually located in sites with higher capacity factors for the purpose of higher investment profits. Hence we assume that within each province installations of wind and solar PV are randomly located in 1 km × 1 km cells where the capacity factors rank in the top 25% (capacity factors of wind and PV are shown in Fig. 3). Furthermore, we assume that a 1 km × 1 km cell is exclusively installed wind turbine or solar PV, and the power densities are assumed to be 3 MW/km^2 for wind [22]

and 20 MW/km^2 for solar PV [23]. Based on the above description installations of wind and solar PV in each 1 km × 1 km cell can be determined, which is then mapped to MERRA-cells. Consequently, wind power output and solar PV power output time series in each MERRA-cell can be obtained respectively. By aggregating all the MERRA-cells the national wind generation and solar PV generation time series (8760 hours) are constructed respectively.

Since the national wind generation and PV generation time series are unknown, the validation of our simulation becomes a problem. But based on national statistics [16, 20], the capacity factor of wind power is in a range of 24.2 – 26.7% and that of PV power is in a range of 11.0 – 18.6% (include the curtailed wind power and PV power). In our simulation capacity factors of wind power and solar PV power are 25.7% and 15.1% respectively. Therefore, to some extent, this simulation is reliable.

2.2. Residual load

Residual load is defined as load minus the sum of hydropower, nuclear power, wind power and PV power. Here, we seek to construct residual load time series.

Firstly, 8760-hour load curve is constructed. Predictions for electricity demand by 2030 are usually ranged in 8.5 – 10 PWh [15, 24]. Here we assume 9 PWh electricity demand. Since national hourly
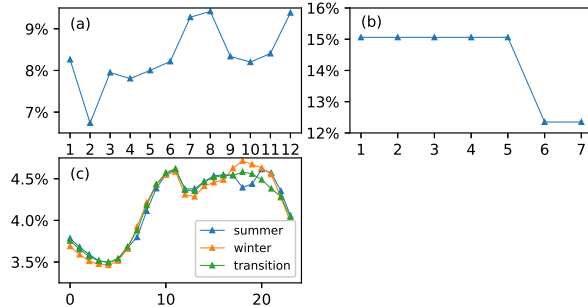
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Figure 4: Normalized monthly (a), weekly (b) and daily (c) load curves.

load records cannot be accessed, a procedure is developed to construct a 8760-hour load curve for the year of 2030 based on load features. Fig. 4 shows normalized monthly load curve, normalized weekly curve and normalized daily load curve. The normalized monthly load curve is based on monthly load data from 2010 – 2016 [25]. The load on weekends is usually lower than that on weekdays varying between 75% and 86% according to load data in European countries (ENTSO-E, https://www.entsoe.eu). Here we assume daily load on weekends is 82% lower than that on weekdays. The normalized daily load curves in summer (Jun. – Aug.), winter (Nov. – Jan.) and transition periods (Feb. – Apr. and Sep. – Nov.) are constructed based on [26] [27]. Hence, the total 9 PWh electricity demand can be split into 8760-hour load based on the normalized monthly, weekly, daily load curves.

In this paper hydropower refers to conventional hydropower. Note that this paper does not take into account pumped hydropower (currently about 26 GW). We assume hydropower is monthly variable. Monthly capacity factors of hydropower are based on national statistics [28] (see Fig. 6). We assume that generation of nuclear power is constant with a capacity factor 81% [16] (see Fig. 6). Annual generation of hydropower, nuclear power, wind power, PV power and thermal power in S1, S2 and S3 is listed in Table 1. As time series data of load, hydropower, nuclear power, wind power and PV

power are prepared, these lead to residual load time series. The shapes of residual load in S1, S2 and S3 are depicted in Fig. 6.

The central authority has set a cap for the total energy consumption to 6 btce by 2030 (billion ton coal-equivalent, as coal is the dominant source in China energy is usually measured by coal-equivalent) [2]. If the average heat rate of coal-fired power plants is assumed to fall to 300 grams coal-equivalent per kWh[2], non-fossil sources (wind, PV, hydro and nuclear) in S1, S2 and S3 will account for 19.35%, 20.65% and 21.80% of total energy consumption respectively (note that the national target is 20%).

3. Measurements of thermal power flexibility

There are two important flexibility parameters for thermal power plants: minimum load level and ramp rate. The minimum load level is the lowest level at which a power plant can operate for an extended time, expressed as a percentage of the maximum capacity. The ramp rate is the average speed at which power output can be increased or decreased between the minimum and maximum load, expressed as a percentage of the maximum capacity per minute [29]. As about 90% of thermal generation comes from coal, we take the average flexibility parameters of coal-fired power plants as reference values. Currently, the minimum load level of coal-fired power plants is about 50–70% [30] and we take 60% as reference value. The average ramp rate is 1%/min [30].

Firstly, we want to assess whether the current 1%/min ramp rate of thermal power plants is sufficient to follow ramps in residual load. It is evaluated based on hourly ramp magnitude and hourly ramp frequency of residual load. Here hourly ramp is defined as changes of residual load between two consecutive hours. Secondly, we want to establish the relationship between minimum load level of thermal power plants and VREs curtailment. Fig. 5 illustrates residual load and VREs generation in two consecutive days. Hereafter we call the maximum in daily residual load as a peak, and the minimum as
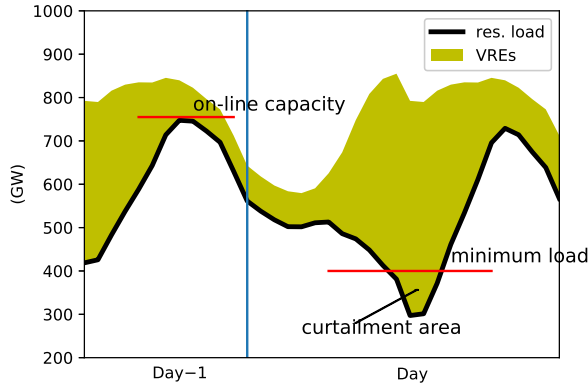
Figure 5: Illustration of residual load and VREs generation in two consecutive days. Thermal power changes between its on-line capacity and minimum load, where on-line capacity is the sum of capacities of all active thermal power plants and minimum load = on-line capacity × minimum load level. We assume that the VREs below the minimum load of on-line thermal power plants are curtailed.

Curtailment Algorithm:
given residual load time series and minimum load level (L)
for each day in one year:
    if $\text{valley}_{day} < \text{peak}_{day-1} \times L$:
        then calculate the area
            between $\text{peak}_{day-1} \times L$ and residual load
output the sum of curtailment areas

Using this simple algorithm, we can estimate what is the minimum load level required to keep VREs curtailment at a low level in the future.

4. Results

In this section, we describe the future scenarios, estimate ramp ability of thermal power plants to deal with ramps of residual load in the future and calculate curtailment rates under minimum load levels of 60%, 40% and 30%.

4.1. Residual load in the future

By 2030 non-fossil sources will account for about 20% in energy use and about 43 – 48% in the electricity system (see Table 1). In particular, VREs account for 16% in S1, 19% in S2 and 22% in S3. The annual electricity demand will continue to grow in the next ten years in China, which is a different case from developed countries. Although a huge amount of wind and PV installed annually, in the future they only partly cover the growth of electricity demand, instead of replacing thermal power. In our scenarios thermal generation will increase from 4.55 PWh currently to 5.13 PWh in S1, to 4.87 PWh in S2, to 4.64 PWh in S3. Note that annual full load hours of thermal power in the future scenarios are still at a low level, 4195 – 4638 hours.

Generation of different sources in each month is shown in Fig. 6. Wind power is extremely lower in June, July, Auguster and September, and PV power is lower in November, December and January. The shapes of daily residual load in S1, S2 and S3 are also depicted in Fig. 6. As observed peaks always appear in the early night when there is no PV power. The new phenomenon is that valleys occur around noon.

a valley. On-line capacity is the sum of capacities of all active thermal power plants, and minimum load equals to on-line capacity multiplying minimum load level. In order to meet the peak in the early night the on-line capacity of thermal power plants has to be greater than or equal to the peak. Then with the decreasing of residual load, these on-line thermal power plants have to ramp down until they reach the minimum load level. As illustrated in Fig. 5, we assume that the VREs below the minimum load of on-line thermal power plants are curtailed. There is no day ahead electricity market in China right now. In reality thermal power generators as the majority in the electricity system do not like to pay for expensive costs of shut-down and start-up [31], and grid companies prefer thermal power as it is stable and easy to manage. Therefore VREs owners are usually the ones suffered curtailment loss. An algorithm is described to calculate the amount of curtailed VREs under a given minimum load level.
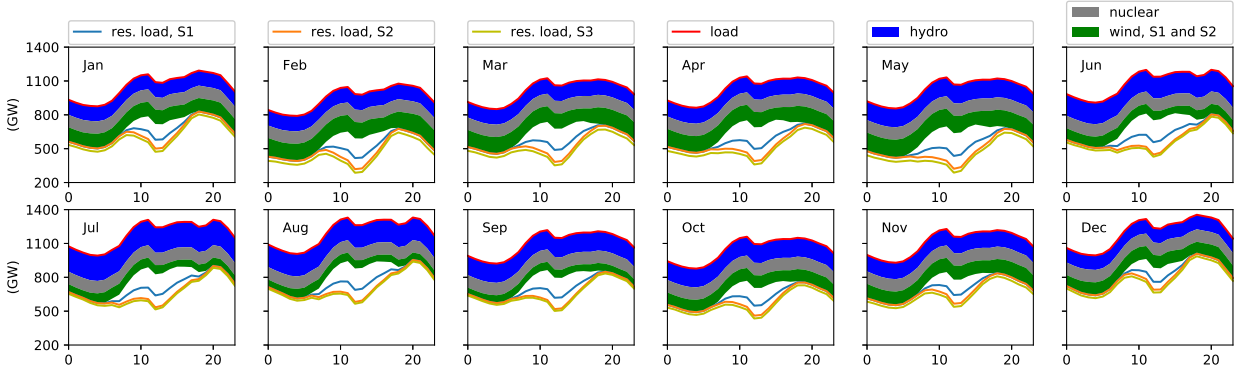
Figure 6: Average daily shapes of load and residual load in S1, S2 and S3 on weekdays, and average daily generation of hydropower, nuclear power and wind power. Hydropower and nuclear power are the same in S1, S2 and S3. Wind generation in S1 and S2 are shown in the green area. Note that in our scenarios setting, S2 has 3% more PV power than S1, and S3 has 3% more wind power than S2. The area between blue line and orange line is the 3% PV power, the area between orange line and yellow line is the 3% wind power.

Note that in our scenarios setting, S2 has 3% more PV power than S1, and S3 has 3% more wind power than S2. The additional 3% PV power in S2 radically drives down valleys around noon. By contrast, the additional 3% wind power in S3 basically does not change the shape. This can be explained that PV power are concentrated in the day, whereas wind power spreads evenly. We see that the increase of PV power does not contribute to reduce capacity of thermal power as no PV power in the night, but it radically lowers valleys, which threatens traditional base-load operation. The peaks in December in S1, S2 and S3 will be as high as 1060 – 1080 GW, which implies in the future it is necessary to keep current 1106 GW thermal power or even more as spinning reserve is also required. Thermal power will continue to play an important role in China's electricity system in the near and medium term.

4.2. Ramp rate

The distributions of hourly ramps of residual load in S1, S2 and S3 are shown in Fig. 7. In S3 the additional 3% wind power only slightly affects ramp magnitude. But the effect of additional 3% PV power is significant in the day. In S2 and S3, the 3% PV power increases downward ramp

magnitude from 6.00 to 12.00, then it enlarges upward ramp magnitude from 12.00 to 18.00. The ramps between 19.00 and 20.00 are separated into two groups, which is because residual load peaks at 19.00 in summer and at 17.00 in winter. Note that the distribution of ramps between 23.00 and 00.00 is quite different from others. It is due to the assumption in simulating residual load time series that load on weekends is 82% lower than that on weekdays. Therefore, residual load will ramp down significantly from Friday's 23.00 to Saturday's 00.00; similarly, ramp up significantly from Sunday's 23.00 to Monday's 00.00. Statistically, in all three scenarios, residual load ramps within ±50 GW with about 70% probability, and within ±100 GW with about 98% probability. Therefore, in the most cases residual load ramps within ±100 GW except the extreme cases mainly happened in transitions from weekdays to weekends or form weekends to weekdays.

Actually hourly ramps within 100 GW in residual load can be followed easily by thermal power, as long as there is sufficient spinning reserve. For example, if in a moment the on-line capacity of thermal power is 800 GW and thermal power output is 600 GW, it can ramp up to 800 GW or ramp down to 480 GW
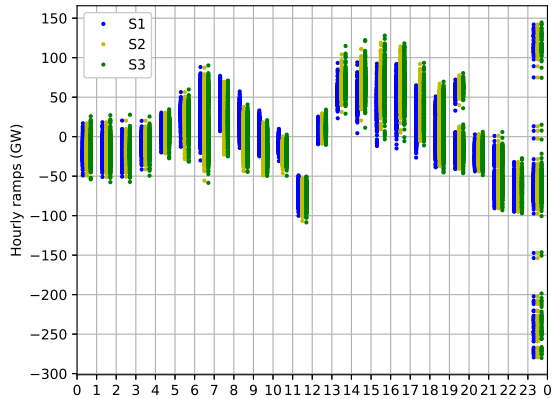
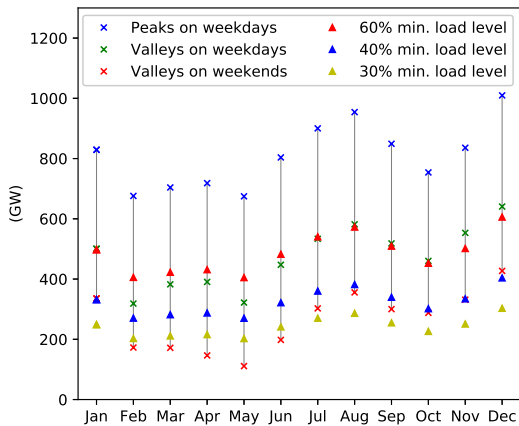Figure 7: Distributions of hourly ramps in 24 hours.

Figure 8: Illustration of positions of average peaks, valleys and minimum load in each month in S2.

(if minimum load level is 60%) in the next hour. Obviously, the current 1%/min ramp ability is sufficient to deal with ramps of residual load in the future.

4.3. Minimum load level and VREs curtailment

The lower minimum load level of thermal power plants means more flexible volume to accommodate VREs. This paper considers minimum load levels of 60%, 40% and 30%, the former is the current average level, the latter two are the expected levels in the future. Fig. 8 illustrates average peaks on weekdays, average valleys on weekdays, average valleys on weekends and positions of 60%, 40% and

Min. load level	60%	40%	30%
S1	16.00%, 947.2	0.94%, 55.7	0.06%, 3.6
S2	19.31%, 1344.0	2.36%, 164.3	0.50%, 34.8
S3	20.71%, 1632.0	3.21%, 253.0	0.88%, 69.3

Table 2: Curtailment rates (the left figures) and economic losses (the right figures, in the unit of 10^8 CNY) in S1, S2 and S3 under the minimum load levels of 60%, 40% and 30% respectively. 1 CNY = 0.125 EUR = 0.145 USD.

30% of peaks in each month. In reality, VREs will be curtailed instead of shut-down of thermal power plants, if the valley is below the minimum load. As observed, if the current 60% minimum load level can be upgraded to 40%, VREs curtailments only happen on weekends; if it is further upgraded to 30%, curtailments only happen on weekends in several months. Obviously, the minimum load level is the key factor limiting flexibility of thermal power plants.

Using the curtailment algorithm, curtailment rates (curtailed VREs/VREs generation) under minimum load levels of 60%, 40% and 30% are calculated (see Table. 2). The results show that if we do not retrofit the existing power plants, the curtailment rates will be as high as 16.0%, 19.3% and 20.7% in S1, S2 and S3 respectively. Such high curtailment rates will greatly sacrifice profits of VREs owners and discourage investment in VREs projects. Hence to further develop VREs the essential step is to improve the minimum load level of thermal power plants. If by 2030 the minimum load level can be improved to 40%, the curtailment rates will radically decrease to 0.9% in S1, 2.4% in S2 and 3.2% in S3; if further improved to 30%, the curtailment rates will be below 1%. The effects of improving minimum load level are significant. We assume the average price of VREs is 0.4 CNY/kWh by 2030 [1]. The corresponding economic losses, the amount of curtailed VREs multiplying the price, are given in Table 2. As we seen, it is a huge economic loss under the 60% minimum load level. However, if the

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[1]Currently, feed-in tariffs for wind power are in a range of 0.4 − 0.57 CNY/kWh in different regions [32], and for centralized PV power are in a range of 0.55 − 0.75 CNY/kWh in different regions[33].

minimum load level can be upgraded to 40%, the saved losses in one year are 891.5×10^8 CNY in S1, 1179.7×10^8 CNY in S2 and 1379.0×10^8 CNY in S3. This is a great economic incentive for the authority to invest in retrofitting of the existing huge thermal power plants to improve minimum load level.

In 2017 VREs curtailment rate is about 18% (12% for wind power and 6% for PV power) [20]. Using the curtailment algorithm given current residual load time series, the corresponding minimum load level is 65% (the reference value is 60%). This gap is partly due to perfect network assumed in simulating residual load time series. With the deployment of UHV (ultra-high voltage) transmission lines [2], which can aggregate the whole country's sources, in the future VREs curtailment because of insufficient inter-province or inter-region transmission lines will be greatly decreased. Hence the estimations of VREs curtailment for the future are reliable in this paper.

5. Conclusions

This paper has described future scenarios with 16 – 22% VREs in China's electricity system and simulated corresponding residual load time series. It has been shown that the penetration of wind power and PV power only partly covers the growth of electricity demand, instead of replacing thermal power. In the future, it is necessary to keep current huge thermal power, or even more, to deal with peaks in residual load. The flexibility requirements of thermal power plants have been estimated based on residual load time series. It has been shown that the current 1%/min ramp rate of thermal power plants is basically sufficient to deal with ramps in residual load in the future, but the current 60% minimum load level has to be upgraded. Curtailment rates will be 16.0%, 19.3% and 20.7% in S1, S2 and S3 respectively, if the minimum load level is unchanged in the future. But the curtailment rates can be sharply decreased to 0.9%, 2.4% and 3.2% in S1, S2 and S3 respectively, if the minimum load can be improved to 40% in the future. The benefits of improving minimum load level from 60% to 40%

can be 891.5×10^8 CNY, 1179.7×10^8 CNY and 1379.0×10^8 CNY in S1, S2 and S3 respectively in one year. This is a huge economic incentive for the central authority to upgrade the average minimum load level of thermal power plants.

In order to improve the flexibility of thermal power plants (mainly coal-fired power plants), the central authority has launched a pilot project in 2016 [34], which requires the minimum load level of condensing units (generate electricity only) to be improved to 30–35%, and that of thermoelectric units (co-generation of power and heat) to be improved to 40–50% by decoupling power and heat using heat storage. Based on the national plan [2], by 2020 there will be more than 200 GW coal-fired power plants retrofitted, mainly in the north, the northeast and the northwest. We believe that by 2030 the average minimum load level of thermal power plants will be at least 40%.

In recent years, PV installation increases dramatically, 43.18 GW in 2015, 77.42 GW in 2016, 130.25 GW in 2017. As discussed, PV power can sharply drive down the valley which is associated with the minimum load level of thermal power plants. From the perspective of system flexibility, the installation of PV should be followed with the improvement of minimum load level. The current exponential speed of PV installation is obviously too fast, which will lead to a result that the more PV is installed, the more PV power is curtailed. The expansion of domestic market of PV is mainly stimulated by the feed-in tariffs [35]. It is necessary to further reduce feed-in tariffs to control the PV installation speed.

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