Dynamic Determination Method of Balancing Capacity for Economic Dispatching Control and Load Frequency Control Considering Vertical Bifacial PV Systems and One-Axis Tracking PV Systems

NISHIDA, Keito
Department of Electrical and Electronics Engineering
University of Fukui
nishida.keito@pws.fuee.u-fukui.ac.jp

SHIGENOBU, Ryuto
Department of Electrical and Electronics Engineering
University of Fukui
lute@u-fukui.ac.jp

ITO, Masakazu
Department of Electrical and Electronics Engineering
University of Fukui
itomasa@u-fukui.ac.jp

IRIGUCHI, Tsuyoshi
Department of Electricity Distribution
Hokuriku Electric Power Transmission and Distribution Company
t.iriguchi@nw.rikuden.co.jp

SHIMIZU, Yasuhiro
Department of Electricity Distribution
Hokuriku Electric Power Transmission and Distribution Company
yasu.shimizu@nw.rikuden.co.jp

Abstract

Under massive PV installation, a PV side has the following challenges: output peak shifting, output curtailment. A vertical bifacial PV system (BiPV) and a one-axis tracking PV system (TPV) are reported to adjust a PV output curve. However, even if installing these PV systems, a power system has a challenge of a shortage of balancing capacity for economic dispatching control (EDC) and load frequency control (LFC) to handle supply-demand imbalances. This paper aims to determine statistically and deterministically a balancing capacity of EDC and LFC according to forecast errors and mid-cycle fluctuations for each UC time step, PV capacity, and PV output level. Then, to verify the effectiveness, this paper plans UC as a day-ahead scheduling while securing balancing capacities determined by the proposed method and executes detailed demand/supply and system frequency simulations as an operation. As a result, the maximum PV capacity increased by 67.2 points for BiPV, and the potential of PV power generation increased by 25.7 points for TPV.

Keywords

Dynamic Determination Method, Balancing Capacity of EDC and LFC, Vertical bifacial PV system, one-axis Tracking PV system, Maximum PV capacity, Potential of PV power generation

1. INTRODUCTION

A synchronous generator (SG) adjusts the output according to a supply-demand imbalance. In planning and operation, firstly, a unit commitment (UC) determines optimal (e.g., minimize fuel cost) SG output based on forecasted value. Each SG is also scheduled as securing output margin for balancing capacity (BC), which is required approximately 2-3% of a system capacity [OCCTO, 2022]. During the operation, a supply-demand imbalance is compensated by the BC margin with SG functions such as economic dispatching control (EDC) and load frequency control (LFC) at several time cycles. Here, the power system under massive PV installation has the following challenges: an increase in forecast error and fluctuations, a reduction in system inertia caused by a decrease in parallel SGs, and the complications of securing BC. Even if the BC is secured at UC scheduling, the challenge remains about a shortage of BC in operation with increasing PV output fluctuation and forecast error [OCCTO, 2022]. In addition, the PV side has the following challenges: output peak shifting, output curtailment, and efficient power generation.

A new PV system has been proposed to change the PV output curve to enhance the power generation by PV and ensure the number of parallel SGs. RAHIMAT et al. [2022] and MARK et al. [2022] reported a vertically installed bifacial PV (BiPV) system and one-axis tracking PV systems (TPV) to improve PV power generation, compared to mono facial PV (MPV) systems. SHIGENOBU et al. [2021] also proposed that the PV peak output is shifted by facing the BiPV's surface to the east or west to strengthen the power system's resilience. In the United States, it has been reported that the introduction rate of TPV reached 90% in 2021 [MARK et al., 2022]. However, BiPV and TPV generate more power than MPV during sunrise and sunset, resulting in steep changes in PV output. Therefore, when introducing BiPV and TPV, the effects on the system frequency by the following occurrences need to analyze; high ramp-up and ramp-down rates of SG output speeds, change in the parallel status of SGs.

A UC is planned according to the demand value. Under a maximum PV introduction, UC should be scheduled flexibly SG's output for the forecast error that changes hourly. In operation, SG must adjust its output considering demand fluctuations, area requirement (AR) and PV fluctuations in real time, and economic efficiency. OKUYAMA et al. [2021] proposed calculating the required BC by creating a forecast error scenario for each UC time step. In this method, the BC is secured by using interconnectors between regions, but detailed analysis has not been performed by considering the demand and PV output fluctuations and forecast errors in real time. Besides, the forecast errors were not considered the amount and direction of the errors. These factors vary not only on time but also on the PV capacity and output levels. On the other hand, TSUJII et al. [2021] discussed calculating the BC derived from the maximum deviation of the PV output fluctuations in real time. SAIDA et al. [2021] proposed setting EDC and LFC target values based on AR fluctuations and generation costs. These studies set EDC and LFC target values considering AR or PV output fluctuations, assuming the SGs continuously operate. When the output fluctuations and forecast errors increase, and the number of SGs is insufficient to secure the BC, SGs stopped have to be started. However, considering the start and shutdown duration time constraints, an early startup before the scheduled time may decline the SG's performance ability.

Therefore, forecast errors and fluctuations should be estimated according to time, PV capacity, and output levels to secure a flexible and accurate BC. Then, the analysis process to calculate and secure BC requires integrating UC scheduling while securing BC and operation.

This paper proposes a method to dynamically determine the required BC (DD-BC) at UC scheduling by time, PV output, and PV capacity levels, considering the introduction of MPV, BiPV, and TPV. Moreover, this paper integrates and analyses the UC scheduling while securing BC and the operation on the day. The BC focused on by the DD-BC consists of the BC of EDC (BC-EDC) and the BC of LFC (BC-LFC). In operation, EDC mainly corresponds to long-term fluctuations, including forecast errors with a cycle time of 30 minutes or more. LFC handles to even shorter periods of mid-cycle fluctuations. To create statistical data that corresponds to PV output levels for each UC time step, forecast errors and mid-cycle fluctuations are calculated from historical time-series data that includes measured and forecasted. Using this statistical data and the PV output forecast, which includes time information, required BC-EDC and BC-LFC are determined for each UC time step. To verify the effectiveness, a UC is scheduled to secure each required BC, and the effect of demand and PV output fluctuations on power system frequency is details analyzed by supply-demand frequency simulation. Finally, the effect of applying the DD-BC is revealed to increase the maximum PV capacity and potential of PV power generation. In addition, the effectiveness of the BiPV and TPV is quantitatively analyzed.

2. ANALSIS MODEL: IEEJ AGC30 MODEL

The AGC30 model [IEEJ] provides the following.

1. Model of SG with each function for various fuels
   - Output by GF, LFC, and EDC command values.
   - Control delay according to oil, coal, and LNG.
2. LFC and EDC model
   - Determinate EDC and LFC command values based on net demand and AR fluctuations.

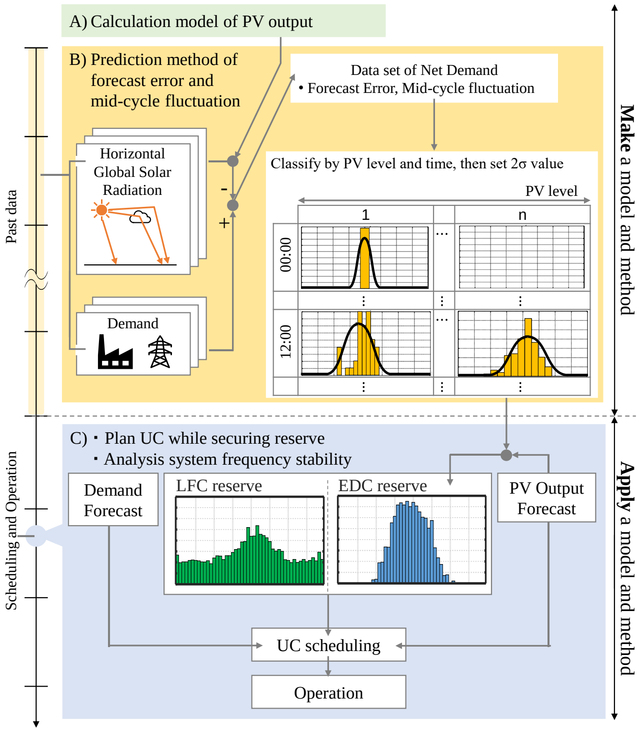

Fig. 1 Flow chart of the proposed method.

   - Set the calculation cycle of LFC and EDC.
3. A framework combining a UC with an operation.
   - Analyze the effect of forecast error and changes in system inertia on system frequency deviation.
   - Evaluate system frequency based on the following equation (1) derived from the oscillation equation.

$$\frac{\sum M_g}{S_B} \cdot \frac{df}{dt} = \frac{\sum P_g - ND}{S_B}, \quad (1)$$

where g is number of SG, f is power system frequency, M_g is an inertia constant [MW·s] at SG g, S_B is reference capacity [MVA], P_g is output [MW] at SG g, ND is net demand [MW].

The AGC30 model calculates result of power system operation scheduled by UC.

3. DYNAMIC DETERMINATION METHOD OF BALANCING CAPACITY (DD-BC)

The "dynamic determination" in DD-BC represents that the required BC is calculated deterministically by considering statistically data of according to forecast errors and mid-cycle fluctuations for each UC time step, PV capacity, and PV output level. Hence, the process secures flexible BC to reflect PV characteristics, as it differs from the conventional BC according to only demand. The DD-BC is divided into stages A, B, and C, as shown below and Figure 1.

A) Calculation model of PV output
   (data collection, output forecast)
B) Prediction method of forecast error and mid-cycle fluctuation of net demand

(statistics: estimate fluctuations and system analysis)

C) Schedule UC while securing BC and operation (deterministic: analyze system frequency stability)

Further details steps of each stage are given as below.

3.1 Stage A: Calculation model of PV output

Considering each PV system, this stage formulates a PV output from available horizontal global solar radiation. Thus, the PV surface irradiance, which depends on azimuth, tilt angle, location, and utilization conditions, is calculated [JSES, 2020]. The available horizontal global solar radiation in UC scheduling uses the 30 minutes value of the day-ahead data.

A1: Direct-diffuse separation

Horizontal global solar radiation includes both the direct radiation that reaches the ground from the sun and the diffuse radiation that is scattered in the atmosphere and reaches the ground. Thus, horizontal global solar radiation is divided into direct and diffuse irradiance.

A2: Calculate the PV surface irradiance

The PV surface irradiance is calculated as sum of the direct, diffuse and ground reflection components, which is given by

$$I_{\beta\gamma} = I_{b\beta\gamma} + I_{d\beta\gamma} + I_{r\beta\gamma}, \tag{2}$$

where $I_{\beta\gamma}$ is PV surface irradiance as azimuth β and tilt angle γ , $I_{b\beta\gamma}$, $I_{d\beta\gamma}$, and $I_{r\beta\gamma}$ are irradiance of a direct beam, diffused sunlight, and ground reflected components, respectively.

A3: Formulate PV output

Using the PV surface irradiance in A2, PV capacity, and a performance ratio, PV output is formulated as follows:

$$P^{PV} = I_{\beta\gamma} \cdot PV \cdot PR, \tag{3}$$

where PV is PV capacity [MW], PR is a performance ratio.

3.2 Stage B: Prediction method of forecast error and mid-cycle fluctuation of net demand

This stage at statistically analyses the past data and makes statistical data then dynamically determines the required BC at UC scheduling by time, PV output level, and PV capacity level, considering the MPV, BiPV, and TPV. Analyzed time step is 30 minutes to create dataset for statistical analysis.

B1: Make a dataset for each fluctuation

This step uses the forecasted and measured net demand introduced by each PV system. Then, the dataset aggregates the forecast errors and mid-cycle fluctuations calculated below.

The forecast error calculates the difference between the forecasted and measured output at the initial time of each time step. The mid-cycle fluctuation calculates the positive and negative maximum deviation between the measured output and value with a moving average applied to the measured output.

B2: Classify each fluctuation using the PV output level

Note that each fluctuation (forecast error and mid-cycle fluctuations) varies constantly, and the amount and direction differ according to weather conditions and time. Thus, the PV output level is adopted as a resolution of weather conditions. The resolution classifies each fluctuation for each UC time step. The PV output level classification range defines that the value divides PV capacity by the total number of SGs with EDC or LFC function. Each fluctuation is classified by the following equations:

$$\boldsymbol{E}_{t,n}^{flu} = \{\varepsilon_{t,d}^{flu} \mid w^{fn} \cdot (n-1) \leq P_{t,d}^{PVfcst} < w^{fn} \cdot n\}, \tag{4}$$
$$w^{fn} = \frac{PV}{\boldsymbol{G}^{fn}},$$
$$flu = \{error, mid\}, fn = \{EDC, LFC\},$$

where t is each UC time step, d is date number, n is PV output level classification number, $\boldsymbol{E}_{t,n}^{error}$ and $\boldsymbol{E}_{t,n}^{mid}$ are the set of each fluctuation for each PV output level classification number n at time t, $\varepsilon_{t,d}^{error}$ and $\varepsilon_{t,d}^{mid}$ are the value of each fluctuation [MW] at time t on date number d , w^{LFC} and w^{EDC} are PV output level classification range for each fluctuation [MW], $\boldsymbol{G}^{LFC}$ and $\boldsymbol{G}^{EDC}$ are the set of SGs with EDC, LFC function, respectively, $P_{t,d}^{PVfcst}$ is PV output forecast [MW].

B3: Make statistical data for various estimation widths

This step evaluates various estimation widths (1σ: 68.3% value, 2σ: 95.5% value, 3σ: 99.7% value) of $\boldsymbol{E}_{t,n}^{error}$ and $\boldsymbol{E}_{t,n}^{mid}$ to consider the economic and robustness. Then, statistical data are created by calculating each estimated fluctuation at all UC time steps and PV output levels. This statistical data indicates the one-to-one correspondence between PV output levels and each fluctuation for each UC time step.

3.3 Stage C: Schedule UC while securing BC and analysis system frequency stability

When the BC is secured deterministically from the statistical analysis (stage B), the importance exists in the width to consider the range (e.g. 1σ, 2σ, 3σ). In the case of 1σ, it is possible to achieve an economical system, but the power system's resilience decreases, and the system frequency may deviate due to insufficient BC during operation. In the case of 3σ, the system has strong resilience, but it is expected to be inefficient and uneconomical. This paper adopts 2σ statistical data and estimates the values of each fluctuation for each UC time step. After scheduling UC, the effect of the PV output fluctuation, the forecast error and demand on the system frequency is analyzed using AGC 30 model.

C1: Estimate each fluctuation for each UC time step

Using the 2σ statistical data created in Step B and the PV output forecast, the forecast error and mid-cycle fluctuation for each UC time step are estimated below

$$\varepsilon_t^{flu} = \{\varepsilon_{t,n}^{flu} \mid w^{fn}\cdot(n-1) \le P_t^{PVfcst} < w^{fn}\cdot n\}, \quad (5)$$

where $\varepsilon_{t,n}^{error}$ and $\varepsilon_{t,n}^{mid}$ are estimated values of each fluctuation of time step t, PV output level classification number n, P_t^{PVfsct} is PV output forecast [MW].

C2: Dynamic determinate BC, UC, and operation

The forecast error and mid-cycle fluctuation calculated in C1 are handled by EDC and LFC, respectively, during operation . Thus, the required BC-EDC and the required BC-LFC at UC scheduling are equal to each estimated fluctuation. Furthermore, the BC-EDC is allocated based on the merit order, and the BC-LFC is allocated in proportion to the SG output speed. Then, the UC is scheduled while satisfying the constraint of securing the BC-LFC in equation (6) and the BC-EDC in equation (7). The UC in this paper determines the optimal output and start-stop state of the SG to minimize the fuel cost. The objective function is the total fuel cost of all SGs, and the constraints are defined as securing each BC, the supply-demand balance, the start and shutdown duration time, the ramp rate of output and the limitation of SG outputs. Further details of the objective function and each constraint are given in previous research [NISHIDA et al., 2022].

【securing the BC-LFC】

$$\sum_{g\in \boldsymbol{G}^{LFC}} \left(p_g^{max} - p_{g,t}^{LFC}\right)\cdot u_{g,t} = LFC_t, \quad (6)$$

【securing the BC-EDC】

$$\sum_{g\in(\boldsymbol{G}^{EDC}\cap \boldsymbol{G}^{LFC})} \left(p_{g,t}^{LFC} - p_{g,t}^{UC}\right)\cdot u_{g,t} \quad (7)$$
$$+ \sum_{g\in(\boldsymbol{G}^{EDC}\cap \overline{\boldsymbol{G}^{LFC}})} \left(p_g^{max} - p_{g,t}^{UC}\right)\cdot u_{g,t} \ge EDC_t,$$

where the first term of securing the BC-EDC represents the amount of BC-EDC secured by a SG that cooperate with both EDC and LFC function, and the second term represents the amount of BC-EDC secured by a SG that has an EDC function but no LFC function. Furthermore, u represents the start-stop state of the SG.

4. NUMERICAL SIMULATION

4.1 Condition

PV capacity [%] is defined as the ratio of the PV capacity [MW] to the maximum demand [MW], which is given by

$$PV\ [\%] = \frac{(PV^{exi} + PV^{add})[\text{MW}]}{max(D)\ [\text{MW}]}, \quad (8)$$

where PV^{exi} is existing PV capacity [MW], PV^{add} is additional PV capacity [MW], D is demand [MW].

Additional PV systems are assumed into five types, as shown in Table 1: south-facing MPV (MS), east-facing BiPV (BiE), west-facing BiPV (BiW), mono facial TPV (MT), and bifacial TPV (BiT). The power generation efficiency on the rear side of BiE, BiW, and BiT is set at 70% [CHRIS et al, 2019]. The existing PV system is assumed MS and set as 1100 [MW] [ANRE], which is the total PV capacity of December 2021 at the three prefectures in Hokuriku in Japan (the demand load during the light load period: 3500 MW, the heavy load period: 5000 MW). Then, a sweeping analysis is performed, increasing the additional PV capacity for each system as a variable.

Stage B uses FY2018 data, and the PV output (existing and additional) to make the dataset is calculated as follows. First, the forecasted and measured PV output for each existing and additional system in FY2018 are calculated. Next, each PV output is normalized by the PV capacity for each month in FY2018 [ANRE]. Finally, the PV output for the dataset is obtained by adding the value of the existing PV system output multiplied by 1100 MW and the value of the additional PV system output multiplied by the additional variable PV capacity.

Table 1 Additional PV installation system.

Case	Tilt	Direction	Module type
MS	20	South	Mono facial
BiE	90	East	Bai facial
BiW	90	West	
MT	Tracking	South	Mono facial
BiT	Tracking	South	Bai facial

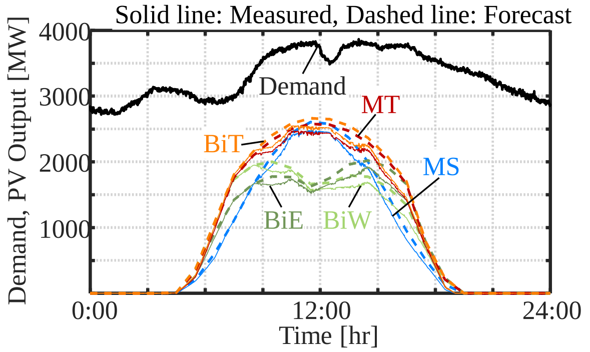

Fig. 2 Demand measured and forecast,
PV output measured and forecast at PV capacity 85.3%.

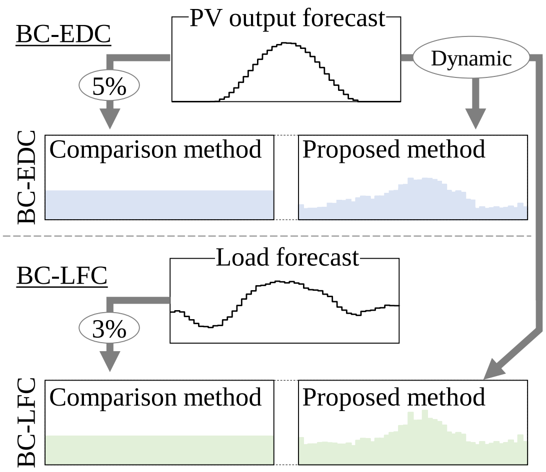

Fig. 3 Profile of comparison and proposed method.

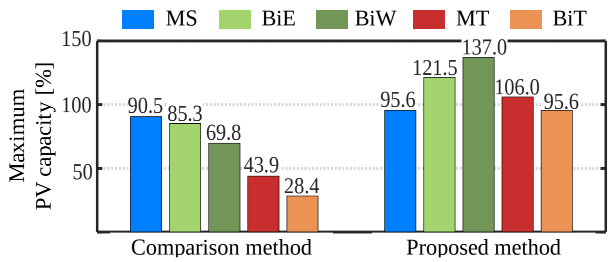

Fig. 4 Maximum PV capacity at each PV system.

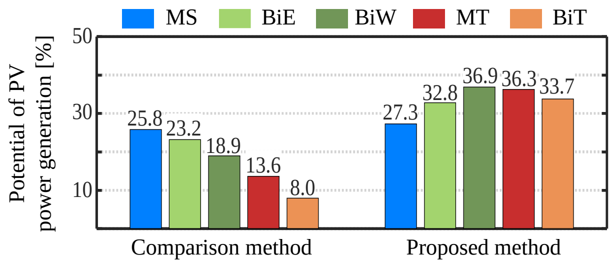

Fig. 5 Potential of PV power generation at each PV system.

Figure 2 shows the forecasted and measured PV output and demand on the analysis day at a PV capacity of 85.3% (existing PV capacity is 1100 MW, additional PV capacity is 2200 MW). The comparison method assumes a constant daily BC-LFC of 3% and BC-EDC of 5%, and the EDC calculation cycle during operation on the day is set to 300 seconds (Figure 3).

4.2 Evaluation indexes

The maximum PV capacity [%] is defined as a maximum value of PV capacity [%] that satisfies the management target value of the system frequency stay rate (±0.1 Hz: 95% or more, and ±0.2 Hz). The potential of PV power generation [%] is defined as the ratio of PV power generation [MWh] at the maximum PV capacity to electricity demand [MWh].

4.3 Results: Maximum PV capacity and Potential of PV power generation

The maximum PV capacity for each method and system is shown in Figure 4, and the potential of PV power generation is shown in Figure 5. As the results, Figure 4 clearly shows that the DD-BC enabled to introduce of PV in the MS by 95.6%, in the BiE by 121.5%, in the BiW by 137.0%, in the MT by 106.0% and in the BiT by 95.6%. Furthermore, an increase in maximum PV capacity is observed in MS by 5.1 points, in BiE by 36.2 points, in BiW by 67.2 points, in MT by 62.1 points, and in BiT by 67.2 points compared to the comparison methods. From Figure 5, by applying the DD-BC, PV generated 27.3% in MS, 32.8% in BiE, 36.9% in BiW, 36.3% in MT, and 33.7% in BiT. Moreover, an increase in the potential of PV power generation is confirmed in MS with 1.5 points, in BiE with 9.6 points, in BiW with 18.0 points, in MT with 22.7 points, and BiT with 25.7 points more than in the comparison methods.

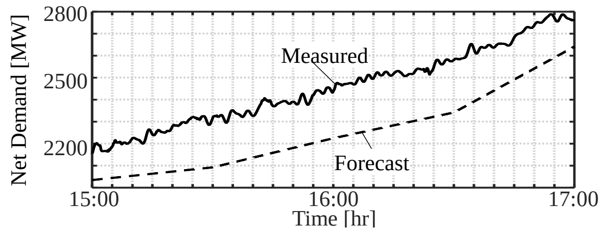

Fig. 6 Measured and forecasted output of net demand.

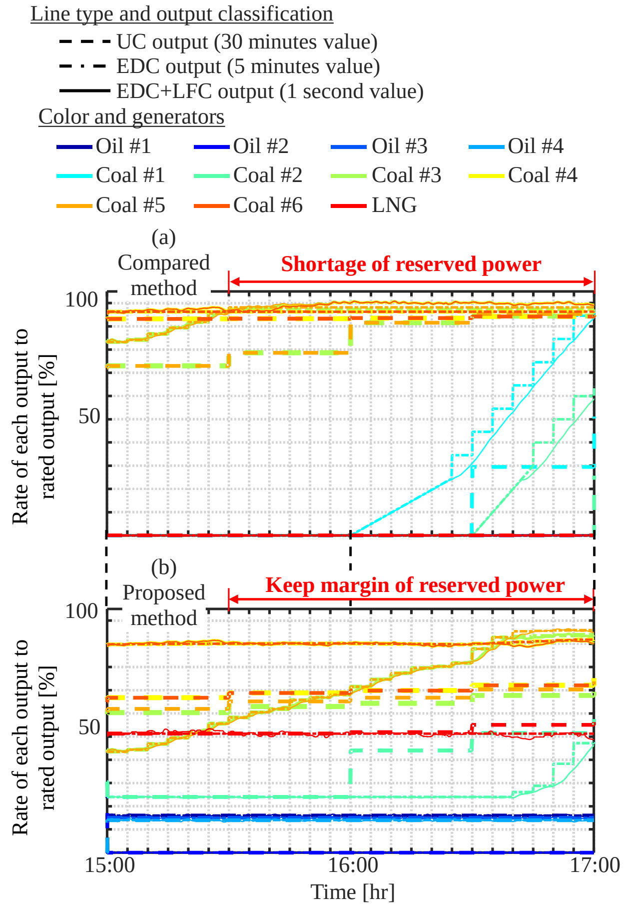

Fig. 7 Rate of output to rated output by applying each method.

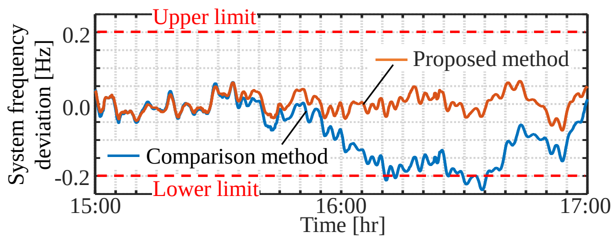

Fig. 8 System frequency deviation by applying each method.

These results indicate that introducing BiW, which shifts PV peaks to the high demand times in the evening, led to the most increase in maximum PV capacity. Also, the introduction of BiT, which generate more efficiently than other PV systems, increased the largest potential of PV power generation.

4.4 Discussion: Power system analysis at BiW

When the BiW was introduced at 75.0%, the net demand during the 15:00 to 17:00 is shown in Figure 6, the ratio of each SG output to its rated output is shown in Figure 7, and the system frequency deviation is shown in Figure 8. Figure 6 shows that the measured net demand exceeded the forecasted value. Thus, each SG has to adjust its output by applying the EDC and LFC functions within the range of the secured BC. Figure 7 (a) reveals that power was supplied by both EDC and LFC functions between 15:00 and 15:30 to handle forecast errors and mid-cycle fluctuations of net demand. After 15:30, the output ratios of all operating SGs reached 100%, which indicated a shortage of BC. In order to secure the BC, one SG was scheduled to start at 16:00 and one at 16:30. However, this situation led to the difficulty of an immediate start-up. Therefore, these SGs could not compensate for the error and fluctuations, consequently, the system frequency deviates the management target value (Figure 8). On the other hand, in Figure 7 (b), the DD-BC ensured no lack of BC, and the EDC and LFC handled correctly to deal with the error and fluctuations of the net demand. Therefore, the system frequency deviation was suppressed within the management target.

5. CONCLUSION

This paper proposed a method to dynamically determine the BC of EDC (BC-EDC) and the BC of LFC (BC-LFC) at UC, separated by each UC time step, PV output level, and PV capacity level, considering the introduction of BiPV and TPV. In this DD-BC, forecast errors and mid-cycle fluctuations were calculated and statistically analyzed to create statistical data that correspond to PV output levels for each UC time step. The required BC-EDC and BC-LFC were determined for each UC time step using this statistical data and the PV output forecast. Then, a UC was scheduled to secure each required BC, and the effect of the demand and PV output fluctuations on the system frequency was analyzed in detail by supply-demand frequency simulation. As a result, it was confirmed that the DD-BC increased the maximum PV capacity and the potential of PV power generation for all PV systems. The introduction of BiW led to the largest increase in maximum PV capacity, with 67.2 points. The introduction of BiT also increased the largest potential of PV power generation by 25.7 points. Furthermore, by analyzing the power system, the DD-BC prevented a shortage of BC-EDC and BC-LFC and kept the system frequency deviation within the management target.

This study adopted the 2σ equivalent value of the past data as the estimated value for each fluctuation. It is possible to increase the estimation range (e.g., 3σ equivalent value) for larger fluctuations and forecast errors. However, the available SG output range may be narrowed, and then the system frequency stability may decrease. Thus, in the future, it is necessary to analyze the effect of different estimated ranges for each fluctuation on the SG output and the system frequency.

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