Multi-Timescale Coordinated AGC of Islanded Microgrids with Cascaded Run-of-the-River Hydropower and Volatile Energies

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Abstract—To enable power supply in rural areas and to exploit clean energy, fully renewable microgrids consisting of cascaded run-of-the-river hydropower and volatile energies such as pv and wind power are built around the world. In islanded operation mode, to ensure frequency stability, the automatic generation control (AGC) of hydropower is essential. However, due to the limited water storage capacity of run-of-the-river hydropower and the river dynamics constraints, without coordination between the cascaded plants, the traditional AGC with fixed participation factors cannot fully exploit the adjustability of cascaded hydropower. When large variations in the volatile energies or load occur, to avoid frequency instability, load shedding can be inevitable, which deteriorates the power supply reliability. To address this issue, this paper proposes a coordinated AGC by jointly considering power system frequency dynamics and the river dynamics that couples the cascaded hydropower plants. The timescales of the power system frequency dynamics and river dynamics are very different. To unify the multi-timescale dynamics to establish a model predictive controller that coordinates the cascaded plants, the frequency dynamics model is approximated as a quasi-stationary one. The cascaded plants are coordinated by optimizing the AGC participation factors in a receding-horizon manner, and load shedding is minimized. Simulation of a real-life microgrid on PSS/E shows a significant improvement in the proposed controller in terms of power supply reliability.

Index Terms—automatic generation control, cascaded run-of-the-river hydropower, coordinated control, hybrid renewable microgrid, model predictive control, multi-timescale control

NOMENCLATURE

\( \tilde{x}, \hat{x} \) The nominal/initial value and the increment of variable \( x \), i.e., \( x = \tilde{x} + \hat{x} \).

\( x, X \) Lower and upper limits of \( x \).

\( \omega \) System frequency deviation.

\( \omega_{\text{ref}} \) System frequency deviation reference.

\( \Omega^G \) Set of hydropower generators.

\( \Omega^{\text{sh}} \) Set of sheddable loads.

\( u_{\text{gi}} \) Guide vane opening of the \( i \)th hydropower unit.

\( P_{\text{gi}} \) Power of the \( i \)th hydropower unit.

\( P^e_{\text{gi}} \) Power reference of the \( i \)th hydropower unit.

\( P_S \) Total power of the volatile energies.

\( P_D \) Load power.

\( T_J \) System inertia time constant.

\( T_{\text{gi}} \) Governor time constant of the \( i \)th hydropower unit.

\( T_{\text{wi}} \) Water hammer effect time constant.

\( R_{\text{gi}} \) Governor droop of the \( i \)th hydropower unit.

\( R_D \) Droop of the load.

\( I_\omega \) Integral of frequency deviation.

\( K_\text{P}, K_\text{I} \) Proportional and integration gains of AGC.

\( c_{\text{gi}} \) Participation factor of the \( i \)th generator in AGC.

\( P_{\text{sh}} \) Total load shedding.

\( P_{\text{sh},i} \) Power of the \( i \)th sheddable load.

\( P_{\text{inj}} \) Nodal power injection vector.

\( P_B \) Vector of the branch power flow.

\( A_{\text{Net}} \) Susceptance-weighted incidence matrix.

\( B_{\text{Net}} \) Nodal susceptance matrix.

\( Q_{\text{turb}}^\text{i} \) Turbine discharge at the \( i \)th hydro plant.

\( Q_{\text{sp}}^\text{i} \) Water spillage at the \( i \)th hydro plant.

\( H_{\text{up}}^\text{i} \) Upstream water stage at the \( i \)th hydro plant.

\( H_{\text{down}}^\text{i} \) Downstream water stage at the \( i \)th hydro plant.

\( \eta_i \) Efficiency of the \( i \)th hydropower unit.

\( g \) Gravity acceleration.

\( H, Q \) Water stage and discharge along the river.

\( W, S \) River width and flow cross-sectional area.

\( I_o, I_f \) River bed and equivalent friction slopes.

\( m \) Manning’s roughness coefficient, \( \text{m}^{-1/3} \text{s} \).

\( \Omega^m \) Set of monitoring points on the river.

\( x_R, u_R, z_R \) River boundary condition vector, including upstream inflow and downstream stage.

\( \text{set} \) \( x_R \equiv [Q^T, H^T]^T \), river state vector.

\( \text{set} \) \( u_R \equiv [Q_{\text{turb}}^\text{i}^T, Q_{\text{sp}}^\text{i}^T]^T \), river control vector.

\( z_R \) River boundary condition vector.
via long-distance transmission lines in normal operation mode, but these need to operate in islanded mode during planned or accidental transmission line outages, especially those caused by natural disasters in rural mountain areas \[2\], \[3\].

In islanded operation, considering the volatility of solar, wind, and load power, frequency stability is one of the most important issues \[9\], \[10\]. Due to the lack of support from an external power grid and energy storage systems (ESSs) such as battery banks in rural areas, the automatic generation control (AGC) of cascaded hydropower is essential to stabilize the frequency against pv/wind and load volatilities.

Until now, on the topic of using cascaded hydropower to mitigate solar and wind volatility, elaborations have been made by the community, including scheduling \[11\]–\[13\] and online control \[15\]–\[17\]. However, these works focus on grid-connected operations. On the other hand, existing studies on the frequency control of islanded microgrids with hydropower focus only on the timescale of the electromechanical dynamics \[9\], \[10\]. However, a study on the AGC of islanded microgrids with cascaded hydropower that considers the coupling between the cascaded plants is, to the best of the authors’ knowledge, still lacking. This paper aims to fill this gap.

To stabilize the frequency against the volatilities of renewable generation and load, AGC needs to adjust the power output of the cascaded hydropower plants. However, the adjustment of cascaded run-of-the-river hydropower is not only limited by the ramping ability of the turbine generators but also subject to the river dynamics. This is because in contrast to the conventional dam hydropower, in run-of-the-river hydropower, the water storage capacity is very limited, and the water energy is spatially distributed along the river. The utilization of water is subject to the river dynamics, and the cascaded plants are therefore hydraulically coupled \[15\]–\[17\]. Moreover, river operation and ecological regulations often require that the water stage along the river is limited within an allowed interval \[18\], which further limits the adjustment of hydropower.

If we do not consider the river dynamics but use a traditional AGC that allocates incremental power with fixed proportions to the cascaded plants, unacceptable violation of the river operation constraints or a large amount of load shedding to maintain the frequency stability may occur, as exemplified in Section IV.C. In contrast, if we consider the river dynamics and accordingly coordinate the cascaded plants by dynamically adjusting the AGC participation factors, as later illustrated in Fig. 3, the adjustment ability of the hydropower can be maximized, and consequently, load shedding can be minimized.

However, power system frequency dynamics and river dynamics, which is usually characterized by the shallow water equations \[15\]–\[19\], have very different timescales, as illustrated in Fig. 2(a). If we directly combine them to establish a model predictive controller (MPC) with a time resolution compatible with the frequency dynamics and a horizon that can accommodate the river dynamics, the curse of dimensionality will arise. To address this issue, we reformulate the AGC dynamics model in a quasi-stationary manner. Thus, the detailed model of frequency dynamics can be replaced by simple algebraic functions and then easily incorporated into the MPC formulation with the dynamic river model without causing the curse of dimensionality, as illustrated in Fig. 2(b).

Following the above presented ideas, this paper proposes a coordinated AGC for islanded microgrids with cascaded run-of-the-river hydropower and volatile generations. The framework of the proposed controller is shown in Fig. 3. Specifically, the following two contributions are made:

1) A approximate quasi-stationary AGC model is deduced for modeling the hydropower turbine discharge as a function of the control arguments (AGC participation factors, frequency reference, and load shedding). This model is a simple algebraic function and thus can be easily incorporated into an MPC formulation.

2) Based on the deduced quasi-stationary AGC model and the dynamic river model based on the shallow water equations, an MPC jointly considering the multi-timescale dynamics is established to update the AGC participation factors in online operation to coordinate the cascaded plants and minimize load shedding.

A simulation of a real-life microgrid verifies that, compared to the traditional AGC, the proposed control approach has a significantly reduced amount of load shedding and improved power supply reliability.
The proposed AGC

The Proposed AGC

Power System
Frequency
Dynamics

MPC Optimizer
(see Section III)

Load, PV, and
Inflow Forecasting

River State/Estimator

Hydropower
Plant 1
Hydropower
Plant 2
Hydropower
Plant 3

Load power
P_L
Solar power
P_S
Load shedding
P_{sh}

Fig. 3. Framework of the proposed controller. The orange, blue, and purple colors represent the electromechanical and hydraulic sides and the controller.

This paper is organized as follows. Section II deduces the quasi-stationary AGC model of islanded microgrid frequency dynamics and introduces the dynamic river model. Section III presents the mathematical formulation of the proposed controller. Finally, in Section IV case studies are presented.

II. MODELING OF THE FREQUENCY DYNAMICS OF A MICROGRID WITH CASCaded RUN-OF-THE-RIVER HYDROPOWER

To coordinate cascaded hydropower plants, the electromechanical side, i.e., the power system frequency dynamics, and the hydraulic side, i.e., the river dynamics, need to be jointly considered. As noted in the Introduction, we deduce a quasi-stationary AGC model in Section II-A to describe the relation between the water discharge of the hydropower plants and the AGC control variables and use the shallow water equations to depict the river dynamics in Section II-B. Then, in Section II-C these models are combined to depict the overall system.

A. Electromechanical Side: Quasi-stationary Model of AGC

Since the electrical distance in the regional microgrids is very short, an islanded microgrid can be approximated as a single aggregated bus [20]. Its frequency dynamics with the PI-based AGC can be modeled as:

\[
\dot{\omega}(t) = \frac{1}{T_D} \sum_{i \in \Omega} P_{Gi}(t) + P_S(t) - \alpha_D (P_D(t) - P_D^{sh}(t))
\]

(1)

\[\dot{P}_{Gi}(t) = \frac{2}{T_{wi}} \left[ u_{Gi}(t) - T_{wi} \dot{u}_{Gi}(t) - P_{Gi}(t) \right], \]

(2)

\[\dot{u}_{Gi}(t) = \frac{1}{T_{gi}} \left[ P_{ref}^{Gi}(t) - \frac{\omega(t)}{R_{Gi}} - u_{Gi}(t) \right], \]

(3)

\[P_{ref}^{Gi}(t) = P_{Gi}(t) + c_{Gi} \left[ K_p (\omega^{ref} - \omega(t)) + K_L I_L(t) \right], \]

(4)

\[\dot{\omega}(t) = \omega^{ref} - \omega(t), \]

(5)

where (1)–(5) represent the rotor and hydro turbine-governor dynamics with consideration of the water hammer effect [20]; (4)–(5) is the PI-based AGC; and

\[\alpha_D = 1 + \omega(t)/R_D \]

is the droop characteristics of the load.

Generally, over short time periods, the frequency can be well stabilized by the hydro governor and PI-based AGC [7]–[10]. However, as noted in the Introduction, considering the river dynamics, the AGC participation factors should be repeatedly optimized to coordinate the cascaded plants over longer time periods. To approximate the relation between the participation factors and the mean turbine discharges for a time period compatible with the river dynamics, (1)–(5) are considered to be quasi-stationary.

Specifically, assuming the left-hand sides of (1)–(5) and (5) to be zero, and using the fact that \( \sum_{i \in \Omega} c_{Gi} = 1 \), we obtain the approximate power output of each hydro generator, as

\[P_{Gi}(t) = c_{Gi} \left[ \alpha_D (P_D(t) - P_D^{sh}(t)) - P_S(t) \right] + \sum_{j \in \Omega} \frac{\omega_{ref}^{Gi}}{R_{Gj}} - \frac{\omega_{ref}^{Gi}}{R_{Gj}}. \]

(7)

Generally, load shedding is realized by tripping feeders. The total amount of load shedding is the sum of the products of the binary variable \( \pi_j(t) \) and the capacity of feeders \( P_{Dj}^{sh}(t) \):

\[P_{Dj}^{sh}(t) = \sum_{i \in \Omega} \pi_j(t) P_{Dj}^{sh}(t). \]

(8)

Substituting (8) into (7) and rearranging, we can approximate the power of each hydropower generator, expressed as a linear combination of \( \omega_{ref}^{Gi} \), \( c_{Gi} \omega_{ref}^{Gi} \), and \( \pi_j c_{Gi} \), as

\[P_{Gi}(t; c_{Gi}, \omega_{ref}^{Gi}, \pi) = \left[ P_D(t) - P_S(t) \right] c_{Gi} - \frac{1}{R_{Gi}} \omega_{ref}^{Gi} + \frac{\sum_{i \in \Omega} 1/R_{Gi}}{c_{Gi} \omega_{ref}^{Gi}} - \sum_{j \in \Omega} P_{Dj}^{sh}(t) \pi_j c_{Gi}. \]

(9)

Note that although in deducing (9) we use a quasi-stationary assumption which is not mathematically rigid, the correctness of (9) is validated numerically. In Section IV-D, more specifically in Fig. 13, the simulation on PSS/E shows that (9) accurately gives the mean values of hydropower outputs over each 10-minute interval, which is adequate for establishing a receding-horizon controller.

Finally, we establish the relation between hydropower generation \( \hat{P}_{Gi} \) and turbine discharge \( Q_{H,i}^{turb} \). \( \hat{P}_{Gi} \) is a nonlinear function of water head \( H_{H,i}^{head} := H_{H,i}^{up} - H_{H,i}^{down} \) and \( Q_{H,i}^{turb} \), known as the production function [21], which is expressed as

\[P_{Hi} = f_{Hi} \left( H_{H,i}^{head}, Q_{H,i}^{turb} \right), \quad i \in \Omega_H. \]

(10)

To facilitate the formulation of the controller, by linearizing (10), turbine discharge is approximated by a linear function as

\[Q_{H,i}^{turb} = \hat{P}_{Gi} \frac{H_{H,i}^{head}}{\eta_i g H_{H,i}^{head}} - \hat{P}_{Gi} \frac{H_{H,i}^{up}}{\eta_i g H_{H,i}^{up}} \]

(11)

Substituting (9) into (11), the turbine discharge \( \hat{Q}_{H,i}^{turb} \) is finally represented as a linear combination of \( H_{H,i}^{up}, H_{H,i}^{down} \), \( c_{Gi}, \omega_{ref}^{Gi}, \) and \( \pi_j c_{Gi} \). In a word, by adjusting these AGC parameters, the turbine discharge can be controlled.

B. Hydraulic Side: State-Space Model of the River Dynamics

In existing studies, two typical models, i.e., the time delay model [13, 14] and the state-space model based on the shallow water equations [15–17], are mostly used to depict cascaded hydropower. The time delay model is more suitable for cascaded large reservoirs but not suitable for run-of-the-river hydropower because river dynamic constraints cannot...
be considered. In contrast, the shallow-water-equation-based model is more suitable for cascaded run-of-the-river plants and dynamic river constraints [22]. Hence, we adopt it here.

The shallow water equations are partial differential equations of the water volume and momentum conservation [19]:

$$
0 = \frac{\partial Q}{\partial t} + \frac{\partial H}{\partial t},
$$

$$
0 = \frac{1}{g} \frac{\partial}{\partial t} \left( \frac{Q}{S} \right) + \frac{1}{2g} \frac{\partial}{\partial y} \left( \frac{Q^2}{S} \right) + \frac{\partial H}{\partial y} + I_f - I_0,
$$

where $y$ denotes the position. The equivalent friction slope $I_f$ is empirically modeled by the Manning–Strickler formula [19]:

$$
I_f = m^2 Q |Q| (W + 2H)^{4/3} S^{-2} (W H)^{-4/3},
$$

where $m$ is typically 0.030 for a natural river and 0.012 for channels [19]. Other parameters such as the river width and slope can be measured or estimated via data assimilation [23].

In normal operation, water stage varies within only a small range. Thus, the river dynamics can be linearized [19]. Then, discretizing the water flow into nonoverlapping cells of length $h$ as Fig. 4 and using the finite-difference format, the linear dynamic river model can be obtained [17], [19] compactly as

$$
\dot{x}_R(t) = A_R x_R(t) + B_R u_R(t) + C_R z_R(t),
$$

where $A_R$, $B_R$, and $C_R$ are constant matrices.

The river control variables $u_R(t)$ are determined by the hydropower plants, and the hydraulic coupling of the cascaded plants is naturally modeled in [15]. The river operation constraints can also be formed with $x_R$. See the detailed deduction of (15) in our previous work [17] or other works [15, 16].

In online operation, a state estimator, e.g., the Kalman filter [24], can be employed to provide river state estimation using available measurements such as the turbine discharges and water stages at the plants. This provides full-state feedback for the proposed controller, as shown in Fig. 3.

### C. The Overall State-Space Model

Substituting the quasi-stationary AGC model [9] and turbine discharge model [11] into the dynamic river model [15], the overall state-space model is obtained compactly as

$$
\dot{x}(t) = Ax(t) + B(P_S(t), P_D(t))u(t) + Cz(t) + u(t)^T F(P_D(t)) u(t),
$$

where $A$, $B(\cdot)$, $C$, and $F(\cdot)$ are coefficient matrices, where $A$ and $C$ are respectively identical to $A_R$ and $C_R$ in [15]; $x(t)$ and $z(t)$ are the same as $x_R(t)$ and $z_R(t)$; $u(t) := [c_{C}(t)^T, \omega^{ref}(t), \bar{\pi}(t)^T, Q^P_{in}(t)^T]^T$ is the vector of decision variables of the controller; $u(t)^T F(P_D(t)) u(t)$ are the quadratic terms of control variables in [9]; $B(P_S(t), P_D(t))$ and $F(P_D(t))$ are functions of $P_S(t)$ and $P_D(t)$.

The framework of this model is illustrated in Fig. 2(b).

### D. Discussion on the Dimensionality of Modeling

In the proposed model (16), because the frequency dynamics are modeled by algebraic functions [9], the state variables are related only to the river dynamics. In the case study in Section IV, the size of the dynamic river model [15] is 200. Considering the MPC step length $T = 600$ s and horizon $N = 12$ or 7, 200 s, the size of the discrete system model [23] is $200 \times 12 = 2400$, which is appropriate for online control.

Otherwise, if additionally considering the detailed frequency dynamics (11–5) with $2 + 2 \times 3 = 8$ states, with a step length of 1 s that is compatible with the frequency dynamics, the overall size of the state reaches $(8 + 200) \times 7200 \approx 1.5 \times 10^8$. Even if the frequency and river dynamics are discretized in different time resolutions, the size of the states reaches $7200 \times 8 + 12 \times 200 = 60000$, 25 times that of the proposed model. If we use an interior point method (IPM) with a time complexity of $O(n^4)$ to solve the MPC, the efficiency of the proposed model is 25$^4$ times better.

### III. FORMULATION OF THE COORDINATED AGC

As shown in Fig. 3, an MPC is employed to repeatedly optimize the AGC participation factors to coordinate the cascaded plants and to give commands of the frequency reference and load shedding in a receding-horizon manner. Given the prediction horizon $N$ and step length $T$, the objective and constraints of the MPC are formulated, as explained below.

#### A. Control Objective

The overall control objective involves maintaining the system frequency and reducing load shedding. Meanwhile, the river state, such as the water stage, should not deviate too far from the nominal. The detailed objective includes the following components.

1) Deviation in the Frequency Reference: According to (9), the load power can be adjusted by the frequency reference, which assists power balance in the islanded system. However, the frequency should not deviate from zero if unnecessary. Therefore, the following quadratic function is minimized:

$$
J_1 = \sum_{k=0}^{N-1} \omega^{ref}(kT)^2.
$$

2) Load Shedding: On the premise of power balance and frequency stability, load shedding should be minimized to improve power supply reliability, which is expressed as:

$$
J_2 = \sum_{k=0}^{N-1} P_{sh}^D(kT).
$$

3) River Stage Deviation: During the control process, the water stage and discharge along the river and channels of the plants should not deviate far from the nominal. This can be achieved by minimizing the following quadratic function:

$$
J_3 = \sum_{k=1}^{N} x_R(kT)^T x_R(kT).
$$

4) Water Spillage: When the upstream inflow exceeds the power demand and the upper limit of the water stage is encountered, plant water spillage is needed to ensure operational security. Spillage occurs only when needed, represented as minimizing

$$
J_4 = \sum_{k=0}^{N-1} \sum_{j \in \Omega^S} Q_{Gi}^p(kT).
$$

Fig. 4. Spatial discretization framework of the water flow [17].
5) Quadratic Terms of the AGC Participation Factors: Finally, to avoid oscillation in the AGC participation factors, the following quadratic term is included in the objective:

$$J_5 = \sum_{k=0}^{N-1} c_G(kT)^T c_G(kT).$$  \hspace{1cm} (21)

The overall control objective is defined as a weighted sum of the above terms with positive weight parameters:

$$J = \lambda_1 J_1 + \lambda_2 J_2 + \lambda_3 J_3 + \lambda_4 J_4 + \lambda_5 J_5.$$  \hspace{1cm} (22)

B. Equality Constraints

The equality constraints in the proposed controller include two components, as listed below.

1) System Dynamics Model: The state-space model \((16)\) is temporally discretized into the equality constraints as:

$$x((k+1)T) = \hat{A} x(kT) + \hat{B} \left(P_2(kT), P_3(kT)\right) u(kT) + \hat{C} z(kT) + u(kT)^T \hat{F} \left(P_2(kT), P_3(kT)\right) u(kT)$$  \hspace{1cm} (23)

for \(k = 0, \ldots, N-1\), where \(\hat{A}, \hat{B}, \hat{C}\) and \(\hat{F}\) are coefficient matrices; the pv/wind power, load power, and river inflow in the future are given as forecasts from the dispatching system.

2) Sum of the AGC Participation Factors: Obviously, the AGC participation factors, frequency reference, and load shedding are updated that the water stage stay within an allowed interval. This is considered at monitoring points along the river and channels:

$$H_{ij} \leq H_i(t) \leq \overline{H}_i, \quad i \in \Omega^m.$$  \hspace{1cm} (35)

If additional constraints such as the switching counting limit of load shedding need to be considered, they can also be easily included in the MPC. To save space, this is not discussed here.

D. MPC Formulation

Summarizing all the above, the overall MPC problem in the proposed coordinated AGC is established:

$$\min_{U} [22], \quad \text{subject to} \quad [23] - [56],$$  \hspace{1cm} (36)

where \(U = [u(0)^T, \ldots, u((k-1)T)^T]^T\) is the sequence of the control variables. The MPC problem \((36)\) is a typical mixed-integer quadratic programming (MIQP), which can be solved using commercial solvers such as IBM ILOG Cplex.

IV. Case Study

A. Simulation Platform

To verify the proposed control method, a detailed simulation platform is established jointly based on PTI PSS/E 34 and Wolfram Mathematica 11.3, as shown in Fig. 5 The electrical side is based on PSS/E, including detailed network, GENCLS generator and HYGOV governor models. The hydraulic side is based on Mathematica, including the shallow-water-equation-based river model \((12) - (13)\), solved by the finite difference method. The electrical and hydraulic sides communicate with each other via the PSSPY interface. The proposed controller \((50)\) is modeled on Mathematica and solved by IBM ILOG Cplex via the NETLink interface. The step length of dynamic river simulation is 10 s, and the control period of AGC is 4 s.

Fig. 5. Comparison of the simulation framework with actual system.
TABLE I
RIVER SECTION DATA IN THE CASCADED HYDROPOWER SYSTEM

| #  | Type            | Length    | Width | Slope | Friction |
|----|-----------------|-----------|-------|-------|----------|
| 1  | Natural River   | 15000 m   | 14.34 m | 1.35% | 0.030    |
| 2  | Natural River   | 10000 m   | 18.23 m | 1.23% | 0.030    |
| 3  | Channel         | 10000 m   | 3.30 m  | 0.07% | 0.012    |
| 4  | Natural River   | 1800 m    | 20.50 m | 1.25% | 0.030    |
| 5  | Natural River   | 11000 m   | 20.84 m | 1.03% | 0.030    |
| 6  | Channel         | 11400 m   | 3.30 m  | 0.07% | 0.012    |
| 7  | Natural River   | 11000 m   | 24.15 m | 1.98% | 0.030    |
| 8  | Natural River   | 8000 m    | 21.64 m | 2.01% | 0.030    |
| 9  | Channel         | 8300 m    | 3.30 m  | 0.07% | 0.012    |
| 10 | Natural River   | 7000 m    | 19.49 m | 1.55% | 0.030    |

TABLE II
DATA OF THE HYDROPOWER PLANTS IN THE SIMULATION

| #  | Name | Rated MW | Initial MW | Ramping Limits | Initial Head |
|----|------|----------|------------|----------------|--------------|
| 1  | MP   | 15 MW    | 8.47 MW    | ±5 MW/min      | 125.6 m      |
| 2  | YJW  | 20 MW    | 12.24 MW   | ±6.67 MW/min   | 181.3 m      |
| 3  | MGQ  | 12 MW    | 6.15 MW    | ±4 MW/min      | 91.0 m       |

B. Case Setting

The real-life microgrid located in Xiaojin County, Sichuan Province, China, shown in Fig. 1, is used in this case study. The data of the ten river sections are listed in Table I and the data of the three cascaded hydropower plants (MP, YJW, and MGQ, from upstream to downstream) that participate in AGC are given in Table II. Four other smaller hydropower plants (HJQ, HK, SGQ, and MW) do not participate in AGC. Their power references are fixed at 2.60, 2.70, 4.00, and 4.20 MW. Five feeders of power 1, 1, 2, 2, and 4 MW at buses 36 and 37 serve as shedding loads, and each one is permitted to switch once per hour. The network constraints are not considered.

We choose to test the proposed controller in the dry season, as in the wet season, there is always abundant water to generate enough electrical power. In contrast, in the dry season, water resources are limited, and the total hydropower generation cannot satisfy the load demands without solar power generation and load shedding. In this situation, the adjustability of the hydropower should be fully exploited, where the proposed coordinated controller shows its value.

Specifically, for this case study, the upstream water inflow and its forecast are as shown in Fig. 6(a), being much smaller than the rated turbine discharge of 33.3 m³/s. The pv and load power and their forecasts are shown in Figs. 6(b) and 6(c).

In the controller, the prediction step length is set as $T = 600$ s. Since the water wave travels through the cascaded plants for one more hour, we set the prediction horizon of the controller to be two-times longer, i.e., 2 hour or $N = 12$. The objective function is set as

\[
L_t = \int_0^{12} F_{\text{D}}(t) dt
\]

with $1 = 10$, $2 = 10$, $3 = 1$, $4 = 1$, and $5 = 10$. The river operational constraints include water stage limits at the monitoring points 800 m upstream of the dams and plants. On natural river reaches and channels, the limits are ±0.2 m and ±0.5 m around the nominal point, respectively. The frequency reference limit is set as ±0.1 Hz.

C. Benchmarking Control Methods and Simulation Results

Four benchmarking control methods (denoted as BMs hereafter) of AGC are used for comparison:

1) BM1: PI-based AGC with fixed participation factors, $\omega_{\text{ref}} = 0$, and no load shedding.

2) BM2: PI-based AGC with fixed participation factors that are proportional to the capacities of the cascaded plants, and $\omega_{\text{ref}} = 0$. Load shedding is based on a mixed-logic controller as in Fig. 7. The decision period of load shedding is 10 min.

3) BM3: Same as BM2, but the frequency reference is set as $\omega_{\text{ref}} = -0.1$ Hz to minimize load power consumption.

4) BM4: A receding-horizon generation scheduling with $N = 12$ and $T = 600$ s is used to determine the nominal power references of the hydropower plants, the frequency reference, and the load shedding every 10 minutes. The PI-based AGC with fixed participation factors calculates the incremental power references to stabilize frequency within each period of 10 minutes. The scheduling model is similar to [35] but without consideration of the adjustment of the AGC participation factors.

Note that BM4 is also first proposed in this paper. As briefly mentioned in the Introduction, to the best of the authors’ knowledge, there is no publication on the AGC of islanded microgrids with cascaded run-of-the-river hydropower. Due to space limit, the detailed model of BM4 is not presented here.

To quantify the performances of the different controllers, the following indices are defined:

1) Total Loss of Load (in MWh):

\[
\text{LoL} = \int_0^{12} F_{\text{D}}(t) dt
\]

2) Root-Mean-Square Frequency Deviation (in Hz):

\[
\text{FD} = \sqrt{\frac{1}{T} \int_0^{T} \omega(t)^2 dt}
\]

By simulation, the performance indices of the benchmarking methods and the feasibility of the river stage constraints are listed in Table III. In detail, because load shedding is not considered in BM1, the water stage at the MP plant descended to an unacceptably low value, as shown in Fig. 8(a). This violates the river operation constraints and may exhaust the water storage; therefore, it is strictly forbidden in operation.
The load shedding control in BM2 ensures that the water stage limits are not violated. However, from the water stage curves in Fig. 8(b), we can see that the cascaded plants are not coordinated at all. This causes the adjustability of the cascaded hydropower to not be fully exploited, leading to the largest load shedding shown in Table III. Setting the frequency reference to the lower limit, i.e., \(-0.1\) Hz, to reduce the load demand in BM3, load shedding still reaches 29.33 MWh.

BM4 coordinates the cascaded plants by scheduling the base power references every 10 minutes. Thus, the adjustability is significantly improved, indicated by the decreased load shedding shown in Table III. However, as shown in Fig. 8(a), the power outputs of the plants deviate from the scheduling within each 10-minute interval due to the solar power and load volatility. This portion of the power adjustment is not coordinated in BM4, in contrast to the proposed method, implied by the differences between the water stage curves of different plants, as plotted in Fig. 8(c). In other words, the adjustability of the hydropower can be further exploited.

### D. Simulation Result of the Proposed Controller

By simulation of the proposed method, the AGC participation factors, as the outputs of the controller, are plotted in Fig. 10. The system frequency reference and the actual deviation are shown in Fig. 11. The power generation of the plants are shown in Fig. 8(b), and a comparison of the total power generation and load shedding to the load demand is given in Fig. 12. The water stages of the plants are given in Fig. 8(d).

The overall performance indices of the proposed method are listed in Table III compared to those of the benchmarking methods. As can be seen, the proposed method further reduces the total load loss and frequency deviation compared to BM4.

The following phenomena exemplify how the proposed method coordinates the cascaded plants. From Figs. 10 and 8(d), at 10:00 am, the stage at the MP plant descends to the lower limit, causing the plant to lose its power adjustability. This is caused by the drop in the upstream inflow shown in Fig. 8(a). In this situation, the proposed controller lowers the AGC participation factor of MP to almost zero in response. After 20:00, since solar power drops to zero and does not fluctuate, the proposed controller slowly adjusts the participation factors to drive the water stages of the plants to rise to the nominal value slowly and synchronously.

Then, comparing Figs. 8(c) and 8(d) (e.g., the magnified parts), over the whole process, the difference between the water stages of the cascaded plants becomes smaller than that under BM4. This outcome reveals that the proposed method better coordinates the cascaded plants. As a result, the load loss and frequency deviation are reduced; see Table III.

Moreover, comparing Figs. 9(a) and 9(b), we can see that the power curves of the proposed method are slightly smoother than those of BM4. This result again shows that the proposed method offers a better coordination of cascaded plants over short time periods. Obviously, this improvement is achieved by considering the multi-timescale dynamics.

In addition, the proposed quasi-stationary model (9) is verified numerically. The mean power of the hydropower plants over every 10-minute interval obtained by model (9) and

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**TABLE III**

| Method | Loss of Load (MWh) | Frequency Deviation (Hz) | Water Stage Feasibility |
|--------|--------------------|--------------------------|------------------------|
| BM1    |                    |                          | Feasible               |
| BM2    | 44.17              | 0.0071                   | Infeasible             |
| BM3    | 29.33              | 0.0384                   | Feasible               |
| BM4    | 15                 | 0.0835                   | Feasible               |
| Proposed | 12                 | 0.0782                   | Feasible               |

---
the actual mean power obtained by the PSS/E-based simulation are comparatively plotted in Fig. 13. Clearly, the incremental hydropower obtained by the quasi-stationary AGC model (9) match with the simulation results with a quite decent accuracy. In addition to the aforementioned good performance of the proposed controller, this result again shows that the quasi-stationary model (9) is adequate for establishing the proposed optimal controller.

E. Simulation Results of the Proposed Control Method under Various Scenarios Compared to those of BM4

To validate the improvement in the proposed method more comprehensively, especially considering the various operational conditions in a real-life system, we tested it under 100 different scenarios. The solar power curves used are empirical data recorded in the Xiaojin system from April to July, 2018. The water inflow and load demand are random samplings. For visualization, 20 out of the 100 scenarios used for simulation are plotted in Fig. 14.

The simulation results of the proposed method are compared to those of BM3 and BM4. The differences between the total load loss and frequency deviation of the proposed method and those of BM3 and BM4 are respectively plotted as one mark per scenario in Figs. 15 and 16. Seen from Fig. 15 compared to BM3, the proposed controller performs dramatically better in terms of reducing both the total load loss and frequency deviation. Comparing the proposed method and BM4, as observed from Fig. 16 most points appear on the left half-plane, meaning that in most scenarios, the proposed method also outperforms BM4 in reducing load loss without compromising the frequency deviation.

Based on all the results above, we can conclude that the proposed multi-timescale AGC better coordinates the cascaded hydropower plants and exploits the overall power adjustability compared to the benchmarking methods. In other words, the proposed method is better in improving the power supply ability and reliability of islanded microgrids with cascaded run-of-the-river hydropower and volatile generations.

V. Conclusions

A coordinated AGC for islanded microgrids with cascaded run-of-the-river hydropower and volatile generations is proposed. An MPC is established to dynamically adjust the AGC participation factors to coordinate the cascaded plants. A simulation of a real-life system shows that the proposed controller improves the power supply reliability compared to that yielded by the other control methods.

Currently, the proposed method has not taken the stochastic characteristics of solar, wind and load power into its modeling and optimization, but recent work has shown that considering these stochastic characteristics improves the control performance [17]. In future studies, taking the stochastic characteristics of the volatile generations and load into consideration could be a promising work direction.

References

[1] J. Chen, Y. Mei, Y. Ben, and T. Hu, “Emergy-based sustainability evaluation of two hydropower projects on the Tibetan Plateau,” Ecological Engineering, vol. 150, p. 105838, May 2020.
