Total transfer capability assessment of HVDC tie-lines in asynchronous grids

Buqing Deng | Yunfeng Wen | Xiaoliang Jiang

1 College of Electrical and Information Engineering, Hunan University, Changsha, China
2 Henan Electric Economic Research Institute, Zhengzhou, China

Abstract
This paper discusses how frequency-stable operational decision-making of asynchronous grids with intensive high-capacity HVDC tie-lines, can be achieved leveraging a novel total transfer capability (TTC) evaluation approach. This problem is formulated as a hierarchical optimization model with multiple decision-makers, in which the master problem is solved by the coordinator to determine the base case maximum acceptable transmission power of each HVDC tie-line, while the sending- and receiving-end grid's local TSO each autonomously solves a frequency constrained optimal power flow sub-problem. Coordinated fast and slow frequency arrest strategies are fully integrated into the TTC assessment framework, which not only ensure that last-resort protections are not triggered following the HVDC bi-pole block contingency, but also take advantage of the potential control capability of the sending- and receiving-end grids and would therefore increase the TTC of HVDC tie-lines. A decentralized algorithm based on accelerated analytical target cascading is developed to solve the formulated model. Case studies on a modified two-area RTS-96 system and a practical large-scale system demonstrate the effectiveness of the proposed approach.

1 INTRODUCTION

An increasing number of ultra-high/high voltage direct current (HVDC) transmission projects have been deployed worldwide to enable the long-distance delivery of massive clean energy generation [1]. So far, 15 ultra HVDC tie-lines have been put into operation in China, thus making some regional sending- and receiving-end grids operating in asynchronous paradigm [2]. For example, the Yunnan Grid is asynchronously interconnected with the main part of South China Grid via 9 HVDC links with a total capacity of 41.6 GW [3]. Early in 2019, the Southwest China Grid realized asynchronous interconnection with the Central and Eastern grids through four high-capacity HVDC links with a total capacity of 30.2 GW.

Although many benefits can be achieved by asynchronous interconnection, asynchronous sending- and receiving-end grids have a lower level of rotational inertia due to the intrinsically zero-inertia feature and non-synchronous interface of HVDC tie-lines [4]. Also, the increasing penetration of renewable generation within the sending/receiving end further jeopardizes the inertia level [5]. Under such circumstance, the huge power imbalance due to an HVDC trip-off might lead to a high-frequency instability in the sending end and a low-frequency collapse in the receiving end, which would finally trigger the last resort protection relays, i.e. over-frequency generation spillage (OFGS) in the sending end and under-frequency load shedding (UFLS) in the receiving end [6]. Therefore, efficiently evaluating the maximum acceptable total transfer capability (TTC) of HVDC tie-lines in asynchronous grids is urgently needed to ensure the economic operation of asynchronous grids and simultaneously guarantee the frequency stability of the sending and receiving ends.

In the literature, extensive efforts have been dedicated to the TTC evaluation of AC tie-lines in synchronous grids. Yang et al. [7] investigated a novel parameter estimation method and developed an output-only based online inter-area TTC assessment method considering small signal stability. Xu et al. [8] presented a TTC evaluation approach for multi-area power systems based on the RPF algorithm, which considers branch N−1 contingencies and other operating limits. Kesherwani et al. [9] proposed...
an evaluation approach of available transfer capability using the holomorphic embedded power flow considering the intact system condition and N-1 contingency conditions. In [10], an interval optimization-based model is deployed for available transfer capability assessment. All these works focus on synchronous grids. Little experience has been achieved to TTC evaluation of asynchronous grids interconnected with large-capacity HVDC tie-lines. Also, traditional centralized TTC evaluation methods are not applicable for application in real-world large power systems managed by multiple decision-makers, i.e. the upper-level coordinator, and lower-level transmission system operators (TSOs) for the sending- and receiving-end grids. This situation necessitates the developing of decentralized approaches to realize hierarchical interacted TTC evaluation between the upper-level coordinator and lower-level TSOs.

Recently, some works [11–13] have explored how frequency-related constraints can be incorporated into power system operation optimization models, such as unit commitment (UC) and optimal power flow (OPF), to enhance the frequency control capability of low-inertia power systems. These works mainly focus on dealing with the potential post-fault frequency violation problem from the system operation point of view, i.e. preparing sufficient online synchronous units and primary reserves to cover a credible contingency. In the absence of coordination between preventive and corrective control measures, as well as the synergy of various fast and slow frequency arrest strategies available in the sending and receiving ends, the produced scheduling/dispatch strategies would be very conservative, and the HVDC links would be operated at derated capacities [14].

Given the above context, this paper investigates how frequency-stable operational decision-making of asynchronous grids with intensive high-capacity HVDC interconnections, can be achieved by leveraging a novel TTC assessment approach. The main contributions are summarized as follows:

1. A hierarchical TTC assessment model oriented to asynchronous grids with multiple decision-makers is proposed. This model can produce the hourly maximum acceptable TTC of each HVDC tie-line, which guarantees post-fault frequency stability of both sending- and receiving-end grids following the HVDC bi-pole block contingency.
2. Coordinated fast and slow frequency control strategies are fully integrated into the TTC assessment framework, which ensures that the last resort protections (OFGS and UFLS) are not triggered following the worst-case contingency. The base case preventive dispatch and post-contingency fast and slow remedial actions are taken into account in a comprehensive manner, the produced TTC evaluation can accurately describe the potential control capability of the sending and receiving ends to deal with the HVDC bi-pole block.
3. A decentralized solution algorithm based on analytical target cascading (ATC) is developed to resolve the large-scale TTC assessment model. Acceleration strategies are introduced to mitigate the total iteration number. Through the use of an interactive solution, the upper-level coordinator and lower-level TSOs could achieve coherence on TTCs of the HVDC tie-lines.

2 | TTC EVALUATION FRAMEWORK FOR ASYNCHRONOUS GRIDS WITH MULTIPLE HVDC TIE-LINES

2.1 | Hierarchical TTC evaluation framework for asynchronous grids

As shown in Figure 1, the asynchronously interconnected sending- and receiving-end grids are operated by an upper-level coordinator and two lower-level TSOs. Accordingly, a hierarchical TTC evaluation framework (linked with a master problem and two sub-problems) applicable for HVDC tie-lines in asynchronous grids is illustrated as follows:

1. Upper level: The coordinator is responsible for HVDC tie-line transmission flows management. Hence, the master problem should be solved by the coordinator to determine the nominal maximum acceptable transmission power of each HVDC tie-line. Post-contingency corrective actions of the remaining HVDC links should be prepared in advance to provide fast frequency control following the HVDC bi-pole block.
2. Lower level: The sending- and receiving-end grid’s TSO each autonomously solves a local frequency constrained optimal power flow (FOPF) problem, which dispatches the generation to meet load demand and also prepares local preventive-corrective combined measures to maintain frequency stability following the HVDC bi-pole block.
3. Interaction between the upper and lower levels: The upper-level coordinator must interact with the lower-level local TSOs to maximize the inter-area power flows transmitted by HVDC tie-lines while, maintaining the frequency stability of the sending- and receiving-end grids following the HVDC trip-off contingency, i.e. avoiding triggering the OFGS and UFLS protections in the sending and receiving end, respectively. Thus, the master problem and sub-problems should be interdependent with the target and response variables.

4. Target variables, including nominal power flows and post-contingency corrective actions of HVDC tie-lines, are produced by the upper-level master problem. After this problem is solved, the target variables will be sent to the sending and receiving ends’ local TSOs.

5. Response variables, which are produced by the sending and receiving ends’ FOPF problems, consist of the HVDC tie-lines’ nominal power flows and post-contingency corrective actions. The response variables define how closely the targets can be met.

During the hierarchical and interactive solution procedure, the coordinator and local TSOs would dynamically change their targets and responses, respectively, to achieve consistency on TTCs of the HVDC tie-lines.

### 2.2 Coordination of fast and slow frequency control

In asynchronous grids with intensive bulk HVDC tie-lines, a single control measure may not be able to maintain system frequency stability following the HVDC bi-pole block [3]. Consequently, to prevent the last-resort frequency defence line (OFGS and UFLS) from being activated in either end, a coordinated frequency arrest strategy that combines fast HVDC corrective actions, and emergency stability control actions, e.g. generation spillage (GS) in the sending end and interruptible load curtailment (ILC) in the receiving end, as well as slow remedial actions (primary frequency control, PFC) are included in the hierarchical TTC evaluation framework. The inclusion of fast flexible actions is essential for accurately estimating the maximum acceptable TTC of each HVDC. Without this consideration, the obtained TTC evaluations would be very conservative, i.e. lower TTC values may be produced.

The coordinated frequency arrest strategy is described as follows:

1. Immediately following the bi-pole block of the $k$-th HVDC at hour $t$ (the initial power loss is $PH_{k,t}$), the remaining HVDC tie-lines will instantly increase their powers to the long-term emergency values, i.e. 110% of the rated capacity.

\[
PH_{k,t} + \Delta PH_{k,t} \leq (1 + \gamma) P_{max}^H
\]  

(1)

Thus, power imbalances of the sending- and receiving-end grids are respectively partially compensated by Equations (2) and (3):

\[
\Delta P^S_{i,t} = PH_{k,t} - \sum_{l \neq k} \Delta PH_{l,t}
\]  

(2)

\[
\Delta P^R_{j,t} = - PH_{k,t} + \sum_{l \neq k} \Delta PH_{l,t}
\]  

(3)

1. Meanwhile, the emergency GS and ILC could be deployed by the sending and receiving ends’ local TSOs to deal with the HVDC bi-pole block. A part of generation units within the sending-end grid can be curtailed by leveraging this fast action strategy. Moreover, shedding certain interruptible loads located in the receiving end is acceptable. As a result, the bulk power imbalances of the two ends can be further reduced to:

\[
\Delta P^S_{i,t} = \Delta P^S_{i,t} - \sum_{j \in RH} PC_{i,j,t}^S
\]  

(4)

\[
\Delta P^R_{j,t} = \Delta P^R_{j,t} + \sum_{j \in RH} \Delta PD_{j,t}^R
\]  

(5)

where the emergency GS and ILC amounts must be bounded within the tolerable ranges:

\[
\forall i \in SH : \sum_{j \in RH} PC_{i,j,t}^S \leq \Delta P_{G_i}^{S,max}, \quad \forall i \in RH : \sum_{j \in RH} \Delta PD_{j,t}^R \leq \Delta P_{D_i}^{R,max},
\]  

(6)

\[
0 \leq \Delta PD_{j,t}^R \leq \varepsilon PD_{j,t}
\]  

(7)

1. The successful implementation of fast HVDC corrective actions and emergency stability control actions should prevent the sending and receiving ends’ post-fault rate-of-change-of frequency (RoCoF) from exceeding the predefined limits.

2. After the governor deadband, generating units located in the sending and receiving ends start to decrease and increase their power outputs (PFR), respectively. During this timeframe, the power imbalance will decrease linearly until it reaches zero at the quasi-steady state. With the coordination of fast and slow control measures, frequency nadirs occurring in the sending and receiving ends should be kept within their acceptable values.

### 3 PROBLEM FORMULATION

#### 3.1 Upper-level coordinator’s master problem

To maximize the HVDC tie-lines’ TTCs and facilitate the coordination between the sending- and receiving-end TSOs, the
The upper-level master problem is formulated as follows as an MILP:

\[
\begin{align*}
\text{max} & \sum_i \sum_t TT_C_{it} \\
& + \sum_t \sum_y \left[ \alpha^S_{h,t} (PH_{ht} - PH^S_{ht}) + \beta^S_{h,t} (PH_{ht} - PH^S_{ht}) \right] \\
& + \sum_t \sum_k \sum_{k \neq k} \left[ \omega^S_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^S_{h,k,t} \right) \\
& \quad + \psi^S_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^S_{h,k,t} \right) \right]^2 \\
& + \sum_t \sum_y \left[ \alpha^R_{h,t} (PH_{ht} - PH^R_{ht}) + \beta^R_{h,t} (PH_{ht} - PH^R_{ht}) \right] \\
& + \sum_t \sum_k \sum_{k \neq k} \left[ \omega^R_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^R_{h,k,t} \right) \\
& \quad + \psi^R_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^R_{h,k,t} \right) \right]^2
\end{align*}
\]

\[s.t.: \quad PH^\text{min} \leq PH_{ht} \leq PH^\text{max}, \forall h \quad \text{Equation (9)}\]

The objective function in Equation (8) maximizes HVDC tie-lines' TTCs (first row in Equation (8)) and coordinates deviations of the target/response HVDC flows and corrective actions (rows 2–5 in Equation (8)), in which the HVDC tie-lines' TTC at hour \(t\) is calculated by \(TT_C_{it} = \sum_y PH_{ht}\).

Equation (9) enforces the base case transmission flow limits of HVDC tie-lines. Equation (10) enforces the power ramping limits of HVDC tie-lines. Equations (11) and (12) ensure that the hourly power flow of each HVDC should be adjusted in a stepwise manner. Equation (13) ensures that the power flow of each HVDC link is not adjusted reversely between adjacent hours. The number of adjustments to each HVDC within the dispatch horizon is constrained by Equation (14) to ensure reliable operation of DC converters [15]. Equations (15) and (16) ensure remaining HVDC tie-lines' corrective action limits following the bi-pole block contingency of the \(k\)-th HVDC.

### 3.2 Sending- and receiving-end TSO’s FOPF problems

In general, the power imbalance due to a generator tripping (or a load loss is much smaller than that caused by the worst HVDC link bi-polar blocking. Consequently, the proposed FOPF explicitly considers frequency stability issues raised by HVDC bi-pole blocking contingencies. The sending- and receiving-end TSOs independently solve their FOPF problems to achieve the following tasks: (1) optimize the generation dispatch to minimize the operating cost; (2) receive target variables from the coordinator, produce response variables and send them to the upper-level coordinator; and (3) prepare preventive and corrective combined measures to ensure the frequency stability. The FOPF model of the two local TSOs is formulated as follows:

\[(i) \quad \text{Sending-end TSO's FOPF problem:} \]

\[
\begin{align*}
\min & \sum_i \sum_t F_i \left( PG^S_{it} \right) + \sum_k \sum_{\rho \neq \psi} VOL_G \cdot PC^S_{s,t,\rho} \\
& + \sum_t \sum_y \left[ \alpha^S_{h,t} \left( PH_{ht} - PH^S_{ht} \right) + \beta^S_{h,t} \left( PH_{ht} - PH^S_{ht} \right) \right] \\
& + \sum_t \sum_k \sum_{k \neq k} \left[ \omega^S_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^S_{h,k,t} \right) \\
& \quad + \psi^S_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^S_{h,k,t} \right) \right]^2 \\
& + \sum_t \sum_y \left[ \alpha^R_{h,t} \left( PH_{ht} - PH^R_{ht} \right) + \beta^R_{h,t} \left( PH_{ht} - PH^R_{ht} \right) \right] \\
& + \sum_t \sum_k \sum_{k \neq k} \left[ \omega^R_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^R_{h,k,t} \right) \\
& \quad + \psi^R_{h,k,t} \left( \Delta PH_{h,k,t} - \Delta PH^R_{h,k,t} \right) \right]^2
\end{align*}
\]

\[s.t.: \quad \sum_i \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (17)}\]

\[
\begin{align*}
& \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (18)}\]
\]

\[
\begin{align*}
& \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (19)}\]
\]

\[
\begin{align*}
& \sum_t \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (20)}\]
\]

\[
\begin{align*}
& \sum_t \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (21)}\]
\]

\[
\begin{align*}
& \sum_t \sum_t \sum_{\rho \neq \psi} PC^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PW^S_{w,\rho} = \sum_i \sum_t \sum_t \sum_{\rho \neq \psi} PH^S_{s,t,\rho} + \sum_y \sum_i \sum_t \sum_{\rho \neq \psi} PD^S_{f,\rho} \quad \text{Equation (22)}\]
\]
DENG ET AL.

OFG relay limits. Equation (30) enforces emergency GS limits as the frequency nadir time \([11, 12]\), so as to avoid triggering the power flow limits of each transmission line within the sending end. Equation (29) ensures that adjustments. Equations (18)–(30), the main differences of this problem include the bi-pole block contingencies, and the terms in the second and third lines in Equation (17) minimize deviations of the target/response HVDCs’ base case flows and post-contingency adjustments.

Equation (18) enforces the hourly system power balance. Equation (19) enforces the generation output limits. Equations (20) and (21) enforce the upward/downward primary reserve procurements of the system. Equation (22) enforces the hourly ramping limits of each unit. Equation (23) enforces the base case power flow limits of each transmission line within the sending end. Equation (24) enforces the HVDC tie-lines’ base case flow. Equations (25) and (26) enforce post-contingency power adjustment limits. Equation (27) determines the sending-end grids’ inertia level. Equation (28) guarantees that the post-fault RoCoF does not exceed the maximum limit. Equation (29) ensures that the primary reserves of the online units are released before the frequency nadir time \([11, 12]\), so as to avoid triggering the OFGS relays. Equation (30) enforces emergency GS limits as described by Equations (2), (4), (6).

(i) Receiving-end TSO’s FOPF problem:

\[
\sum_b SF_{b,i} \left[ \sum_i KG_{h,i} PG_{i,j} + \sum_w KW_{h,w} PW_{w,j} \right] - \sum_b KH_{b,i} PH_{h,b} - \sum_j KD_{b,j} PD_{j,b} \leq PH_i^{\text{max}} \]

\[
PH_{b,i} \leq \Delta PH_{h,b,i} \leq PH_{b,i}^{\text{max}}, \forall b, i \quad (23)
\]

\[
PH_{h,b}^{\text{min}} \leq PH_{h,b} \leq PH_{h,b}^{\text{max}}, \forall b \quad (24)
\]

\[
PH_{h,b}^{\text{max}} + \Delta PH_{h,b} \leq (1 + \gamma) PH_{h,b}^{\text{max}}, \forall b \neq k \quad (25)
\]

\[
\Delta PH_{h,b,i} \leq \Delta PH_{h,b}^{\text{max}}, \forall b \neq k \quad (26)
\]

\[
H_j^R = \frac{\Delta P_{h,i}^{\text{max}}}{2PH_i^{\text{max}}} \leq \text{RoCoF}_{h,i}^{\text{max}} \quad (27)
\]

\[
RD_{b,i} \leq 2R_{b,i}^R \left( f^0 + f \Delta PH_{h,b,i} \right) \quad (28)
\]

\[
\sum_b SF_{b,i} \left[ \sum_i KG_{h,b} PG_{i,j} + \sum_w KW_{h,w} PW_{w,j} \right] \leq PH_i^{\text{max}} \quad (30)
\]

\[
PH_{b,i}^{\text{min}} \leq PH_{b,i} \leq PH_{b,i}^{\text{max}}, \forall b \quad (29)
\]

\[
PH_{h,b}^{\text{max}} + \Delta PH_{h,b} \leq (1 + \gamma) PH_{h,b}^{\text{max}}, \forall b \neq k \quad (31)
\]

\[
\Delta PH_{h,b,i} \leq \Delta PH_{h,b}^{\text{max}}, \forall b \neq k \quad (32)
\]

\[
0 \leq RU_{b,i}^{\text{min}} \leq RU_{b,i}^{\text{max}}, 0 \leq RD_{b,i}^{\text{min}} \leq RD_{b,i}^{\text{max}} \quad (33)
\]

\[
0 \leq RU_{b,i}^{\text{max}} \leq RU_{b,i}^{\text{max}}, 0 \leq RD_{b,i}^{\text{max}} \leq RD_{b,i}^{\text{max}} \quad (34)
\]

\[
\sum_i RU_{b,i}^{\text{max}} \leq \text{max} \left\{ \sum_i RD_{b,i}^{\text{max}} \right\}, \sum_i RU_{b,i}^{\text{max}} \geq \text{TRD}_{b,i}^{\text{max}} \quad (35)
\]

\[
\sum_i RU_{b,i}^{\text{max}} \leq \sum_i RU_{b,i}^{\text{max}}, \sum_i RD_{b,i}^{\text{max}} \leq \sum_i RD_{b,i}^{\text{max}} \quad (36)
\]

\[
\sum_b SF_{b,i} \left[ \sum_i KG_{h,b} PG_{i,j} + \sum_w KW_{h,w} PW_{w,j} \right] \leq PH_i^{\text{max}} \quad (37)
\]

\[
PH_{b,i}^{\text{min}} \leq PH_{b,i} \leq PH_{b,i}^{\text{max}}, \forall b \quad (38)
\]

\[
PH_{h,b}^{\text{max}} + \Delta PH_{h,b} \leq (1 + \gamma) PH_{h,b}^{\text{max}}, \forall b \neq k \quad (39)
\]

\[
\Delta PH_{h,b,i} \leq \Delta PH_{h,b}^{\text{max}}, \forall b \neq k \quad (40)
\]

\[
H_j^R = \frac{\Delta P_{h,i}^{\text{max}}}{2PH_i^{\text{max}}} \leq \text{RoCoF}_{h,i}^{\text{max}} \quad (41)
\]

\[
RoCoF_{h,b}^{\text{R}} \leq \text{RoCoF}_{h,b}^{\text{R max}} \quad (42)
\]

\[
RU_{b,i}^{\text{R}} \leq 2R_{b,i}^{R max} \left( f^0 + f^0 \text{UFLS} + f^R \text{db} \right) \quad (43)
\]

Post-contingency emergency control limits (3), (5), (7).

Unlike the sending-end TSO’s FOPF model Equations (17)–(30), the main differences of this problem include the following: (1) HVDC tie-lines’ power flows are treated as generation in Equations (32), (37), and (42)–(44); (2) Rather than incorporating the GS, post-contingency curtailment of interruptible loads is included in the objective function and Equations (42)–(44) to prevent a low-frequency collapse; (3) The required total upward primary reserves is set larger than the actual power imbalance following the worst HVDC bi-pole block with the emergeny support from remaining HVDCs’ corrective actions and interruptible load curtailments; (4) RoCoF and frequency nadir constraints representing post-fault low frequency variations Equations (42), (43) are enforced to avoid triggering the RoCoF and UFLS relays.
4 | SOLUTION METHODOLOGY

The non-linear terms involved in Equations (29) and (43) can be removed using the McCormick envelope [16]. Thus, the master problem (MILP) and two sub-problems (LP) can be iteratively solved using the ATC algorithm to achieve coherence on the TTCs of the HVDC tie-lines.

4.1 | Accelerated strategies

Accelerated strategies presented in [17] are introduced to enhance the convergence performance of the ATC. The traditional ATC is improved by adopting a prediction type acceleration step, in which the concept of momentum is used to prevent the algorithm from decelerating with the increased number of iterations.

At iteration $n$, the received targets in objective functions Equations (17) and (31) are replaced by:

\[
\Delta PH_{h,k} = PH_{h,k}^{m+1} - PH_{h,k}^m
\]

\[
\Delta PH_{h,k} = \frac{1}{\sigma_n} (PH_{h,k}^{m+1} - PH_{h,k}^m) - \Delta PH_{h,k}^{m-2}
\]

\[
\forall b \neq k
\]

where $\sigma = 1$ and $\sigma_n = (1 + 4\sigma_{n-1})/2$.

The Lagrange multipliers at iteration $n+1$ are updated based on the actual values achieved at iterations $n$ and $n-1$ as follows:

\[
\alpha_{h,k}^{n+1} = \alpha_{h,k}^n + \frac{\sigma_n - 1}{\sigma_{n+1}} (\alpha_{h,k}^n - \alpha_{h,k}^{n-1}), \beta_{h,k}^{n+1} = \rho \beta_{h,k}^n
\]

\[
\omega_{h,k}^{n+1} = \omega_{h,k}^n + \frac{\sigma_n - 1}{\sigma_{n+1}} (\omega_{h,k}^n - \omega_{h,k}^{n-1}), \psi_{h,k}^{n+1} = \rho \psi_{h,k}^n
\]

\[
\alpha_{h,k}^{n+1} = \alpha_{h,k}^n + \frac{\sigma_n - 1}{\sigma_{n+1}} (\alpha_{h,k}^n - \alpha_{h,k}^{n-1}), \beta_{h,k}^{n+1} = \rho \beta_{h,k}^n
\]

\[
\omega_{h,k}^{n+1} = \omega_{h,k}^n + \frac{\sigma_n - 1}{\sigma_{n+1}} (\omega_{h,k}^n - \omega_{h,k}^{n-1}), \psi_{h,k}^{n+1} = \rho \psi_{h,k}^n
\]

4.2 | Solution procedure

The flowchart of this improved ATC based decentralized solution algorithm with acceleration techniques is given as follows:

5 | CASE STUDY

The proposed HVDC TTC assessment approach is tested on a modified two-area RTS-96 system and a large-scale practical power system in China. All formulations are modeled on the GAMS platform and solved using the CPLEX MILP/LP solver. Solutions produced by the CPLEX solver are input to the MATLAB/Simulink model to simulate the frequency dynamics for each HVDC bi-pole block contingency. All experiments are performed on a personal computer with an Intel Core i7-4700MQ 4-Core CPU (2.4 GHz) and 8 GB of memory. For both test systems, the following modes are defined for comparison:

Improved ATC with acceleration techniques

1. Input parameter data and initialize all multipliers.
2. For $n \in N$:
   a. Solve the sending-end TSO’s FOPF sub-problem using LP, then upload the obtained responses variables $(PH_{h,k}^*, \Delta PH_{h,k}^*)$ to the upper-level coordinator.
   b. Solve the receiving-end TSO’s FOPF sub-problem using LP, and send the produced responses variables $(PH_{h,k}^*, \Delta PH_{h,k}^*)$ to the upper-level coordinator.
   c. The coordinator solves the master problem using MILP to obtain the target variables $(PH_{h,k}^*, \Delta PH_{h,k}^*)$.
   d. Check the convergence condition. If yes, then the algorithm terminates. Otherwise, modify the produced target variables using Equations (45)–(46), and update the multipliers using Equations (47)–(50).
   e. Broadcast the updated target variables and multipliers to the lower-level TSOs, and then repeat step 2.

Mode 1: without considering frequency stability constraints, the hourly total primary reserve requirement is set at the capacity of the largest synchronous unit.

Mode 2: considers frequency stability constraints with HVDC corrective control but not the post-contingency emergency GS and ILC measures.

Mode 3: considers frequency stability constraints with post-fault HVDC corrective control and emergency GS and ILC measures.

The size of the spinning reserve is directly related to the output of generators, and then affects the TTC of the HVDC links. Therefore, the spinning reserve in each area of the three modes is also optimized.

5.1 | The modified two-area RTS-96 system

The modified two-area RTS-96 system is depicted in Figure 2, where the sending and receiving ends are connected by three HVDC links h1 (500 MW), h2 (600 MW) and h3 (750 MW). The wind farms located at the sending end are at buses 107, 113, 114, 117, 118, and 123, with a total capacity of 2000 MW. At the receiving end are buses 207 and 204 with a total capacity of 300 MW. The maximum allowable adjustment number of each HVDC is set at 6, and the emergency overload rate is set at 10%. The governor’s deadband is 33 mHz, the maximum tolerable RoCoF is 0.8 Hz/s, and the triggering frequencies of OFGS and UFLS are set at 50.5 and 49.2 Hz, respectively.
Table 1 compares results produced by the three modes. TTE and TOC represent the total transferred energy of HVDC tie-lines and the total operating cost, respectively. $\text{InTTE}$ and $\text{InTOC}$ are respectively the increased transferred energy and operating cost produced by modes 2 and 3 in comparison with those produced by mode 1. We can observe that mode 1 obtains the cheapest solution with transmitting the most energy (43,373 MWh). However, because frequency stability constraints are not considered in the model, the solution would result in serious frequency collapse both at the sending- and receiving-end grids following the worst HVDC bi-pole block. The total transferred energy of HVDC tie-lines produced by mode 2 is 38,879 MWh ($-10.36\%$ lower than mode 1), which is the most expensive one among the three modes ($4.0\%$ higher than mode 1). Thus, imposing frequency constraints leads to a decrease in the TTE and an increase in the TOC. The TTE (40,782 MWh) produced by mode 3 is only $5.97\%$ less than produced by mode 1, and its TOC ($4,902,236$) is just $2.27\%$ higher than mode 1. Therefore, compared with modes 1 and 2, mode 3 achieves a good compromise between TTE and TOC, which can guarantee the transfer capability of HVDC tie-lines while achieving a considerable cost reduction.

Figure 3 shows hourly TTCs of each HVDC tie-lines produced by the three modes. The hourly TTCs of HVDC links $h2$ and $h3$ under mode 2 should be set significantly lower than those produced by mode 1 to ensure frequency stability (only relying on corrective control of remaining HVDC links and primary frequency control of synchronous units), so as to obtain manageable contingency sizes caused by the HVDC trip-off contingency. In contrast, with the emergency support from GS (sending end) and ILC (receiving end), the average hourly TTCs produced by mode 3 can be upgraded. Therefore, the HVDC transmission capacity can be maximally applied in mode 3.
Table 2 compares the hourly worst contingency size (hourly largest TTC, i.e. $\max\{PH_t^h\}$) and post-contingency corrective actions produced by modes 2 and 3. The corrective actions include power adjustments of remaining HVDCs (modes 2 and 3, denoted as HC), emergency GS and ILC (only mode 3). One can observe that the hourly largest TTC of the three HVDC tie-lines produced by mode 3 is larger than those produced by mode 2 at almost all periods. The reason is that the post-contingency power imbalance could be reduced to the greatest extent with coordinated fast and slow frequency control strategies in mode 3. Thus, primary reserves and HVDC corrective actions needed to cover the actual power loss are considerably reduced. Then, the hourly base case TTC can be improved. For example, at hour 17, the maximum acceptable TTC of HVDC link $h3$ produced by mode 3 is 705 MW, which is 116.14\% of that produced by mode 2 (607 MW). To cope with the huge power imbalance (607 MW) caused by the bi-pole block of HVDC link $h3$, Mode 2 requires 180 MW increased powers provided by the remaining HVDC tie-lines $h1$ and $h2$. In mode 3, the total post-contingency HVDC power adjustment amount is reduced to 148 MW, while the emergency GS (26 MW) and ILC (66 MW) are triggered respectively by the sending- and receiving-end grids to ensure the frequency stability both grids.

Figures 4 and 5 respectively show the hourly post-contingency RoCoFs and frequency nadirs produced by modes 1 and 3 for the sending- and receiving-end grids. The post-fault RoCoFs and frequency nadirs of both ends produced by mode 3 strictly satisfy the operating requirements. This condition further demonstrate that the proposed model can produce TTCs of HVDC tie-lines while guaranteeing the frequency stability of the system under the coordination of fast and slow frequency control strategies. By contrast, the post-fault RoCoFs and frequency nadirs achieved by mode 1 do not satisfy their limits at most hours, because the power imbalance caused by the HVDC bi-pole block contingency exceeds the total primary reserves of the sending and receiving ends.

The solutions at hour 20 produced by modes 1 and 3 are selected for frequency dynamics simulation. The results are shown in Figure 6. For model 1, since frequency stability constraints associated with the HVDC bi-pole block are not involved, the power imbalance (735 MW) caused by the HVDC bi-pole block contingency leads to a sharp increase at the sending end (the frequency nadir reaches 51.0 Hz) and a dramatic drop at the receiving end (the frequency nadir approaches 46 Hz), OFGS relays at the sending end and UFLS relays at the receiving end must be activated to cope with serious frequency

![Figure 6](image-url)
violations, which will result in a part of generation and loads being curtailed in the sending and receiving ends, respectively. For mode 3, the fast frequency arrest strategies can immediately reduce the initial power imbalance (691 MW) to a relatively low level, i.e. 517 MW power surplus at the sending end (with 148 MW HVDC corrective actions and 26 MW GS), and 524 MW power loss at the receiving end (with 148 MW HVDC corrective actions and 19 MW ILC). The altered power imbalances can be fully covered by the downward and upward reserves of the sending- and receiving-end grids, respectively. As a result, frequency violation problems of the sending and receiving ends after the fault are effectively suppressed, and the expansion of the fault range are avoided.

Figure 7 shows the evolution of TTE and total operating cost of the sending and receiving ends produced by mode 3 solved by the traditional and accelerated ATC. The traditional ATC converges after 50 iterations to obtain the optimal solution, while the accelerated ATC only needs 22 iterations. Moreover, the solution time decreases from 498 to 213 s. Therefore, the introduced multiplier updating strategies can effectively accelerate the convergence speed of the ATC algorithm.

5.2 Asynchronous interconnected China southern power grid

The asynchronous interconnected China Southern power Grid (CSG) are used to test the performance of the proposed TTC assessment approach in a large-scale practical system. That the receiving end of this practical system does not encounter frequency instability problems following the worst HVDC bipolar blocking. As shown in Figure 8, Yunnan grid is asynchronously interconnected with the main part of CSG through 9 HVDC links with a total capacity of 41.6 GW. The nominal transmission capacities of KL. UHVDC, NC HVDC, CS HVDC, PQ UHVDC, XD UHVDC, J2 HVDC, YF HVDC, LX HVDC, and YG HVDC are 8000, 6400, 5000, 5000, 5000, 3200, 3000, 3000, and 3000 MW, respectively.

Figure 9 shows the hourly TTC of each HVDC tie-line produced by modes 1–3. For modes 1 and 3, except for the KL. UHVDC, the hourly TTCs of other HVDC tie-lines can be set at their nominally rated power capacities. For Mode 3, the produced TTCs of the KL. UHVDC at all periods are lower than those produced by mode 1. The purpose is to ensure that frequency violation problems caused by bi-pole block of the KL. UHVDC can be handled by the coordinated fast and slow frequency control strategies. For mode 2, because frequency control capability of the sending- and receiving-end grids are limited (emergency GS and ILC control are not enforced), the hourly TTCs of the KL. UHVDC are cut down to below 6500 MW, and the hourly TTCs of the NC HVDC are also lower than the rated power capacity. Therefore, the proposed approach can improve the inter-area TTCs of practical large-scale asynchronous grids with intensive high-capacity HVDC tie-lines.

Figure 10 compares the hourly post-contingency RoCoFs and frequency nadirs produced by modes 1 and 3 for the sending end.
coordinated fast and slow frequency control strategies. Figure 11 shows the post-contingency frequency dynamics of the sending end at hour 20 produced by modes 1 and 3, which further illustrates the effectiveness of the proposed frequency arrest strategies.

Figure 12 depicts the convergence curve of the TTE and TOC produced by mode 3 solved using traditional and accelerated ATC. The results produced by accelerated ATC nearly coincide with those obtained by traditional ATC after only 25 iterations. The traditional ATC takes 721.7 s to converge with TTE and TOC of 983,470 MWh and $98,425,173, respectively, while the accelerated ATC obtains the final solution after 514.3 s.

6 | CONCLUSION

A hierarchical TTC assessment approach oriented to asynchronous grids with intensive and high-capacity HVDC tie-lines is proposed. A decentralized solution algorithm based on ATC is developed to resolve the large-scale TTC evaluation model with multiple decision makers. Simulation results on the modified two-area IEEE RTS-96 system and a practical system in China demonstrate the following: (1) The TTC evaluation procedure of HVDC tie-lines must consider potential frequency instability issues caused by the HVDC bi-pole block contingency; (2) The maximum acceptable TTCs of HVDC tie-lines can be significantly improved by considering the coordinated fast and slow frequency control strategies, thereby relieving the stress of primary reserve procurement and increasing the utilization factor of HVDC tie-lines; (3) The solution efficiency of the ATC algorithm can be improved by applying the accelerated strategies.

ACKNOWLEDGMENTS

The authors would like to express our gratitude to all editors and reviewers for your valuable comments and suggestions. This research was supported by National Natural Science Foundation of China (52077066), Hunan Provincial Natural Science Foundation for Excellent Young Scholars (2020JJ3011), and Huxiang Young Talents Science and Technology Innovation Program (2020RC3015).

NOMENCLATURE

Throughout the paper, the superscripts S and R indicate the sending- and receiving-end grids, respectively.

\[ F_i \] Cost function of synchronous unit \( i \).

\[ PH_{i,j} \] Initial power imbalance at hour \( t \).

\[ I_{i,j} \] Whether the \( b \)-th HVDC tie-line adjusts its power at hour \( t \).

\[ \Delta P_{h,b}^{\max} \] Emergency ramping limit of the \( b \)-th HVDC tie-line.

\( f^0 \) Nominal frequency value.

\( \tau_{b, \min} \) Minimum duration time interval.

\( \varepsilon \) Predefined constant.

\[ PG^S_{i,t}, PG^R_{i,t} \] Power output of unit \( i \) at hour \( t \).

\[ RU^S_{i,t}, RU^R_{i,t} \] Hourly upward primary reserve of unit \( i \).

\[ RD^S_{i,t}, RD^R_{i,t} \] Hourly downward primary reserve of unit \( i \).

\[ \Delta P_{h,b}^\prime, \Delta P_{h,b}'' \] Imbalance power following HVDC corrective control and GS/ILC.

\[ RoCaF_{h,t}^S, RoCaF_{h,t}^R \] Post-contingency RoCaF at hour \( t \).

\[ \tilde{x}^+, \tilde{x}^-_{h,b} \] Power adjustment step rising and falling edge of the \( b \)-th HVDC link.

\[ PG^S_{i,t}, PG^R_{i,t} \] Minimum output limit of unit \( i \).

\[ PG^S_{i,t}, PG^R_{i,t} \] Maximum output limit of unit \( i \).

\[ PW^S_{w,t}, PW^R_{w,t} \] Output of wind farm \( w \) at hour \( t \).

\( PD^S_{j,t}, PD^R_{j,t} \) Load demand of bus \( j \) at hour \( t \).

\[ \Delta RH_{h,b}^\prime, \Delta RH_{h,b}^\prime \] Ramping-up/down rate limits of the \( b \)-th HVDC tie-line.

\[ PH_{h,b}^{\min}, PH_{h,b}^{\max} \] Minimum/maximum power limits of the \( b \)-th HVDC tie-line.

\[ RU_{i,t}^S, RU_{i,t}^R \] Upward primary reserve limits.

\[ RD_{i,t}^S, RD_{i,t}^R \] Downward primary reserve limits.

\[ DG^S_{i,t}, DG^R_{i,t} \] Ramping-down rate limit of unit \( i \).

\[ UG^S_{i,t}, UG^R_{i,t} \] Ramping-up rate limit of unit \( i \).
Shift factor matrices.

Total upward/downward primary reserve requirements.

Maximum power limit of line \( l \).

Inertia constant of unit \( i \).

System inertia level at hour \( t \).

Maximum tolerable RoCoF.

Ramping rate of unit \( i \).

OFGS/UFLS triggering frequency.

Frequency deadband.

Imbalance power following HVDC corrective control.

Post-contingency curtailed powers of unit \( i \) and load \( j \).

Generation spillage and interruptible load curtailing limits.

Maximum allowable adjustment number and overload coefficient of HVDC link \( b \).

Base case power of the \( b \)-th HVDC tie-line at hour \( t \).

Post-contingency increased power of the \( b \)-th HVDC tie-line at hour \( t \).

Lagrangian multipliers.

**Indices and Sets**

**B Variables**

**C Parameters**

Indices of HVDC tie-lines and AC lines.

Indices of synchronous units, loads, wind farms.

Indices of contingencies, time periods, iteration numbers.

Sets of triggered units and interruptible loads.

Penalty factors of generation and load shedding

**REFERENCES**

1. Wang, T., et al.: Coordinated modulation strategy considering multi-HVDC emergency for enhancing transient stability of hybrid AC/DC power systems. CSEE J. Power Energy Syst. 6(4), 806–815 (2020)

2. Shu, Y., Tang, G., Pang, H.: A back-to-back VSC-HVDC system of Yu-E power transmission lines to improve cross-region capacity. CSEE J. Power Energy Syst. 6(1), 64–71 (2020)

3. Zhou, B., et al.: Principle and application of asynchronous operation of China southern power grid. IEEE J. Emerging Sel. Top. Power Electron. 6(3), 1032–1040 (2018)

4. Zhang, M., Yuan, X., Hu, J.: Inertia and primary frequency provisions of PLL-synchronized VSC HVDC when attached to islanded AC system. IEEE Trans. Power Syst. 33(4), 4179–4188 (2018)

5. Gu, H., Yan, R., Saha, T.K.: Minimum synchronous inertia requirement of renewable power systems. IEEE Trans. Power Syst. 33(2), 1533–1543 (2018)

6. Ai, Q., et al.: Frequency coordinated control strategy of HVDC sending system with wind power based on situation awareness. IET Gener. Transm. Distr. 14(16), 3179–3186 (2020)

7. Yang, D.Y., et al.: Synchronized ambient output-only based online inter-area transfer capability assessment considering small signal stability. IEEE Trans. Power Syst. 36(1), 261–270 (2021)

8. Xu, S., Miao, S.: Calculation of TTC for multi-area power systems based on improved ward-PV equivalents. IET Gener. Transm. Distr. 11(4), 987–994 (2017)

9. Kesherwani, S., Mohapatra, A., Srivastava, S.C.: An efficient holomorphic embedded based approach for available transfer capability evaluation. Int. J. Electr. Power Energy Syst. 122, 1–10 (2020)

10. Kou, X., Li, F.: Interval optimization for available transfer capability evaluation considering wind power uncertainty. IEEE Trans. Sustainable Energy 11(1), 250–259 (2020)

11. Wen, Y., et al.: Frequency dynamics constrained unit commitment with battery energy storage. IEEE Trans. Power Syst. 31(6), 5115–5125 (2016)

12. Wen, Y., et al.: Toward flexible risk-limiting operation of multi-terminal HVDC grids with vast wind generation. IEEE Trans. Sustainable Energy 11(3), 1750–1760 (2020)

13. Nguyen, N., et al.: Optimal power flow incorporating frequency security constraint. IEEE Trans. Ind. Appl. 55(6), 6508–6516 (2019)

14. Kalsha, M.M., Rather, Z.H.: A new control scheme for fast frequency support from HVDC connected offshore wind farm in low-inertia system. IEEE Trans. Sustainable Energy 11(3), 1820–1837 (2020)

15. Farsani, P.M., Vennalaganti, S.G., Chaudhuri, N.R.: Synchrophasor-enabled power grid restoration with DFIG-based wind farms and VSC-HVDC transmission system. IET Gener. Transm. Distr. 12(6), 1339–1345 (2018)

16. Sherali, H.D., Adams, W.P.: A Reformulation-Linearization Technique for Solving Discrete and Continuous Nonconvex Problems. Springer, Berlin (1998)

17. Safarian, F., Mohammadi, A., Kargarian, A.: Temporal decomposition for security-constrained unit commitment. IEEE Trans. Power Syst. 35(3), 1834–1845 (2020)

How to cite this article: Deng, B., Wen, Y., Jiang, X.: Total transfer capability assessment of HVDC Tie-Lines in asynchronous grids. IET Gener. Transm. Distr. 1–11 (2021). https://doi.org/10.1049/gtd2.12223