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New modeling framework considering economy, uncertainty, and security for estimating the dynamic interchange capability of multi-microgrids

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ABSTRACT

The increasing integration of distributed generation introduces severe challenges to the secure and economical operation of multi-microgrids (MMGs). Therefore, an accurate and timely estimation of secure ranges for dynamic interchange adjustments is necessary for microgrid operators. This study develops a new modeling framework for estimating the interchange capability between MMGs and a distribution network (DN) to increase the situation awareness of the microgrid operator. This framework contains a two models, namely, (1) the proposed prediction model, which considers the economical operation, the robustness of power interchange, and the uncertainty of renewable resources on a microgrid level to obtain the operation states and predicted interchange capabilities, and (2) the correction model, which determines the available interchange capabilities (AICs) while considering the effect of security constraints and spinning reserve on the DN level. AICs ensure the control flexibility and security of microgrids. The approach based on model predictive control is used in this framework to optimize the system operation on the microgrid and DN levels. The point estimation method and second-order conic programming are used to solve the two-level model to guarantee a globally optimal solution and improved computational efficiency. Finally, a distribution system with multiple microgrids is applied to prove the effectiveness of the proposed framework.

1. Introduction

Technological advancements, environmental policies, and energy market deregulation have spurred the deployment of distributed generators (DGs), small renewable installations, and large distributed energy storage systems. Traditional paradigms, which rely on centralized power generation and are distributed through medium-voltage and low-voltage networks, have been adapted to incorporate aggregated systems of DGs (i.e., microgrids) [1]. Coupled with the increasing importance of the Energy Internet, microgrid is one of the fundamental units that provide the same power as the grid with the potential to improve its reliability, power quality, and environmental impact through controls and the coproduction of heating and cooling [2]. The full exploitation of multi-microgrids (MMGs), which involves the design of a new control architecture and the development of novel management tools, has attracted research attention in recent years [3–7].

The dynamic adjustment of interchange flow between adjacent microgrids allows microgrid operators to utilize available internal and external flexible generation resources and available transfer capability (ATC) and provide market participants with cost-saving opportunities in both regions efficiently. In Ref. [5], a centralized multi-objective optimization algorithm was proposed to coordinate MMGs optimally based on a distribution-interline power flow controller. An optimal control algorithm was presented in Ref. [6] for the management of grid-connected MMGs with the Monte Carlo (MC) method. This algorithm finds the optimal operating points of each dependent system in an active distribution grid. Meanwhile, Ref. [7] proposed a decentralized optimal power flow algorithm to coordinate the MMGs and improve the overall performance of a distribution network (DN).

From the development trends of renewable energy and energy marketization, future active distribution grids may include numerous microgrids that work as independent systems with different rules, constraints, and objectives (e.g., reliability maximization, cost minimization, and emission minimization) [5]. Every microgrid operator seeks to manage the amount of power exchange dynamically rather than implement power transactions with no control on

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Nomenclature

Symbols, abbreviations, and acronyms

min, max	Minimum and maximum
dch, ch	Discharge and charge
MGCC	Microgrid control center
DNCC	Distribution network control center
PIC	Predicted interchange capability
DPICP	Dynamic power interchange capability prediction
DPICC	Dynamic power interchange capability correction
MG	Microgrid
DG	Distributed generator
PV	Photovoltaic
WT	Wind turbine
MT	Microturbine
DE	Diesel engine
ESD	Energy storage device
BESS	Battery energy storage system
SOC	State of charge

Variables and parameters of the microgrid model

$P_{Mi}^{j,t}$, $P_{Di}^{j,t}$	Power production of the *i*th MT and the *i*th DE at hour *t* in the *j*th microgrid
$P_{W}^{j,t}$, $P_{V}^{j,t}$	Power production of the WT and PV at hour *t* in the *j*th microgrid
$P_{ULi}^{j,t}$, $P_{ILi}^{j,t}$	Power consumption of the *i*th uninterruptible load and the *i*th interruptible load at hour *t* in the *j*th microgrid
$P_{MTL}^{j,t}$, $H_{MTL}^{j,t}$	Power and heat transmission from cooperative microgrids to the *j*th microgrid at hour *t*
$P_{PCC}^{j,t,dn}$, $P_{PCC}^{j,t,up}$	Minimum and maximum power interchange capabilities between the *j*th microgrid and DN at hour *t*
$P_{PCC}^{j,t}$	Power transaction at hour *t*, $P_{PCC}^{j,t} < 0$ if the *j*th microgrid purchases power from the DN and $P_{PCC}^{j,t} > 0$ if the *j*th microgrid sells power
$P_{Si}^{j,t}$	Power production of the *i*th ESD at hour *t* in the *j*th microgrid
$W_{Si}^{j,t}$	Stored energy inside the *i*th ESD at hour *t* in the *j*th microgrid
$P_{DGi}^{j,t}$	Power production of the *i*th DG at hour *t* in the *j*th microgrid
$H_{L}^{j,t}$	Heat demand in the *j*th microgrid at hour *t*
UR_{Mi}, DR_{Mi}	Ramp-up/down rates of the *i*th MT
UR_{Di}, DR_{Di}	Ramp-up/down rates of the *i*th DE
N_M	Number of cooperative microgrids
N_T, N_D, N_S, N_I, N_U	Numbers of MT, DE, and ESD units and interruptible and uninterruptible loads in the *j*th microgrid

Variables and parameters of the distribution network model

$\bar{P}_{PCCi}^{t,dn}$, $\bar{P}_{PCCi}^{t,up}$	Minimum and maximum predicted interchange capabilities between the microgrid and DN at the *i*th bus and hour *t*
$\hat{P}_{PCCi}^{t,dn}$, $\hat{P}_{PCCi}^{t,up}$	Minimum and maximum available interchange capabilities between the microgrid and DN at the *i*th bus and hour *t*
P_{Li}^{t}, Q_{Li}^{t}	Active/reactive powers of the *i*th bus at hour *t*
P_{Gi}^{t}, Q_{Gi}^{t}	Active/reactive power productions of the slack bus at the *i*th bus and hour *t*
P_{Bi}^{t}, Q_{Bi}^{t}	Active/reactive power productions of the BESS at the *i*th bus and hour *t*
E_{Bi}^{t}	Stored energy inside the BESS at the *i*th bus and hour *t*
Q_{PCCi}^{t}	Reactive power production of the microgrid at the *i*th bus and hour *t*
$r_{Gi}^{t,dn}$, $r_{Gi}^{t,up}$	Down/up spinning reserve provisions of the slack bus at the *i*th bus and hour *t*
$r_{Bi}^{t,dn}$, $r_{Bi}^{t,up}$	Down/up spinning reserve provisions of the BESS at the *i*th bus and hour *t*
V_{i}^{t}	Voltage of the *i*th bus at hour *t*
δ_{ij}^{t}	Voltage phasor difference between the *i*th and *j*th buses at hour *t*
g_{ij}, b_{ij}	Conductance and susceptance between the *i*th and *j*th buses
N_{DN}, N_G, N_B	Numbers of buses, grid-connected microgrids, and BESS in the DN

its tie-line power. Thus, microgrid operators must have real-time knowledge of the secure range for potential interchange adjustments to accomplish the objective of each independent microgrid.

Methods for determining the secure interchange adjustment range include security region methods [8–10] and various advanced nonlinear methods, such as direct methods [11], continuation methods [12–14], nonlinear optimization approaches [15,16], and distributed computation frameworks [17,18]. The majority of these methods are applied to ATC estimation for independent power systems [9–16], while several calculate the interchange capability between multi-area power systems [8,17,18]. Most of these methods consider only physical system constraints (e.g., power line transmission capacity and voltage magnitude) or stability constraints (e.g., limit-induced and saddle-node bifurcations) while preventing the current or near-future system operation situation. Furthermore, a single case study [11–15] cannot cover all operational scenarios even under maximum load generation. Specifically, a single case study for a complicated system, such as MMGs, is highly likely to be significantly different from actual system operating conditions. Thus, the analysis result corresponds to neither an economical nor a secure system operation.

This study develops a new modeling framework that consists of models for dynamic power interchange capability prediction and correction (DPICP and DPICC, respectively) for estimating the secure interchange adjustment range between MMGs and DNs to address the problems mentioned. In the DPICP model, each microgrid operator solves a stochastic multi-objective dispatch problem with a look-ahead period for obtaining the possible economical dispatch points and predicting the upward/downward ramping capability of MMGs. The following uncertainties are dominant in this stochastic problem: (1) heat and electricity load demands and (2) photovoltaic (PV) and wind turbine (WT) power forecast errors. Furthermore, the upward/downward ramping capabilities of controllable units, including microturbine (MT) and diesel engine (DE), are considered in this model. The DPICP model is suitable for calculating the predicted interchange capabilities (PICs) from the perspective of MMG operators who must execute the trade-off between operation cost and control robustness. However, the influence of the exchanging power of MMGs on the security of the DN cannot be overlooked. Therefore, DPICC model-based corrective control measures must be implemented to avoid contingencies on the DN level.

The major contributions of this study are as follows. (1) A new modeling framework based on the model predictive control (MPC) approach is designed for estimating a secure range for dynamic interchange adjustments between MMGs and the DN. The available interchange capabilities (AICs) can still be obtained under this framework should some microgrids isolate themselves from