Enhanced Flexible Ramping Product Formulation for Alleviating Capacity Shortage in Look-ahead Commitment

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***Abstract*—The roll-out of a flexible ramping product provides independent system operators (ISOs) with the ability to address the issues of ramping capacity shortage. ISOs procure flexible ramping capability by committing more generating units or reserving a certain amount of headrooms of committed units. In this paper, we raise the concern of the possibility that the procured flexible ramping capability cannot be deployed in real-time operations due to the unit shut-down in a look-ahead commitment (LAC) procedure. As a solution to the issues of ramping capacity shortage, we provide a modified ramping product formulation designed to improve the reliability and reduce the expected operating cost. The trajectories of start-up and shut-down processes are also considered in determining the ramping capability. A new optimization problem is formulated using mixed integer linear programming (MILP) to be readily applied to the practical power system operation. The performance of this proposed method is verified through simulations using a small-scale system and IEEE 118-bus system. The simulation results demonstrate that the proposed method can improve the generation scheduling by alleviating the ramping capacity shortages.**

***Index Terms*—Flexible ramping product, look-ahead commitment (LAC), mixed integer linear programming (MILP), reliability.**

Nomenclature

A. Indices and Sets

Ω_t	Set of time periods
Ω_g	Set of generators
Ω_{fg}	Set of fast-start generators, $\Omega_{fg} \subset \Omega_g$
Ω_{sg}	Set of slow-start generators, $\Omega_{sg} \subset \Omega_g$
g	Index of generator, $g = G_1, G_2, ..., G_N$
t	Index of time period, $t = 1, 2, ..., T$

B. Parameters

α_t	Additional ramping capability requirement to cover 15-min-ahead net load forecasting error
C_g^{NL}	No-load cost of generator g
C_g^{LP}	Linear production cost of generator g
C_g^{SU}	Start-up cost of generator g
MP	A big number to penalize load shedding
NL_t	Short-term forecasting net load during period t
$P_g^{\max}$	The maximum production capacity of generator g
$P_g^{\min}$	The minimum production capacity of generator g
$P_g^{SU,k}$	Power output of generator g in the k^{th} interval of start-up process applied only for slow-start units
$P_g^{SD,k}$	Power output of generator g in the k^{th} interval of shut-down process applied only for slow-start units
RR_g	Ramping rate of generator g
RR_g^{SU}	Start-up ramping rate of generator g
RR_g^{SD}	Shut-down ramping rate of generator g
SU_g	Duration of start-up process of generator g applied only for slow-start units
SD_g	Duration of shut-down process of generator g applied only for slow-start units
$UFRC_t, DFRC_t$	Requirements for upward and downward flexible ramping capabilities of system during period t

C. Variables

δ_{gt}^{SD}	Auxiliary variable of generator g to calculate negative downward ramping capability during period t
δ_{gt}^{SU}	Auxiliary variable of generator g to calculate negative upward ramping capability during period t
DR_{gt}	Downward flexible ramping capability of generator g during period t
LS_t	Continuous variable of load shedding during period t

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NUR_{gt}	Negative contribution of generator g to system upward flexible ramping capability during period t
NDR_{gt}	Negative contribution of generator g to system downward flexible ramping capability during period t
p_{gt}	Power output of generator g during period t
$\bar{p}_{gt}$	The maximum available power output of generator g during period t
UR_{gt}	Upward flexible ramping capability of generator g during period t
x_{gt}	Binary variable, which is equal to 1 if generator g generates power above the minimum capacity during period t and 0 otherwise
y_{gt}	Binary variable, which is equal to 1 if generator g starts up during period t and 0 otherwise
z_{gt}	Binary variable that is equal to 1 if generator g shuts down during period t and 0 otherwise

I. Introduction

LARGE-SCALE renewable energies such as solar and wind power are being introduced into power systems in order to avoid carbon emissions from fossil fuels and moderate global warming [1]. The increasing penetration of renewable energy is expected to continue owing to recent innovations in renewable generation technologies together with cost competitiveness. However, the non-dispatchable characteristics of renewable energy resources are posing new challenges to power system operators, that is to say, the considerable uncertainty and variability in the output of renewable generation should be considered in power system operations [2].

Traditionally, power system operators make unit commitment decisions considering various types of reserves to cover the uncertain and variable nature of net load, i.e., the demand minus the output of renewable generation. Much attention has been paid to estimate the optimal requirements for reserves to accommodate the increasing amount of renewable energy resources [3]-[5]. The approach of providing an appropriate amount of deterministic reserves has advantages in that it could be readily applicable to practical power system operations. Another way to manage the uncertainty and variability of net load is the application of a stochastic programming model [6]-[8], which attempts to minimize the expected operating costs for net load in the plausible scenarios without any explicit reserve constraints. This approach is economically preferred to the deterministic approach, but it has limitations in computational complexity, market settlements definition, and practical implementation [9]-[11]. Policy functions have been developed to reduce the computational burden and make the stochastic programming more practical in the application of batteries to power system scheduling [12] and reserve responses to contingencies [13].

To deal with the increasing uncertainty introduced by renewable energy, a look-ahead commitment (LAC) model is commonly used in independent system operator (ISO) market to optimize the commitment of resource. In California ISO (CAISO) market, a short-term unit commitment is solved for 15-min intervals in the real-time market and the commitment decisions can be implemented starting from the intervals in the trading hour [14]. However, in some ISO markets, the commitment solutions from LAC are not mandatory. For example, in PJM and Midcontinent ISO (MISO) market, LACs are recommendations and dispatchers have the operation discretion. In particular, MISOs only adhere to 32% of the LAC recommendations, which may be attributable to the sub-optimality of the recommendations [15].

In addition to reserve products, to further integrate renewable energies, some ISOs have introduced ramping services in their electricity markets. CAISO and MISO have ramping services known as “flexiramp” and “ramp capability product”, respectively, which are designed to improve the operation capability to ramp from one generation level to another during the successive dispatch intervals [16], [17]. Flexible ramping capability (FRC) products and reserves share similarities in that both ancillary services set aside a predefined amount of generation capacity. However, their purposes and the expected deployment time have a clear distinction. FRC products withhold generation capacity, expecting to use the procured capability one interval later. The main objective of FRC products is to compensate the ramping capacity shortage. In contrast, ISOs ensure that the reserves are available to deal with contingencies that might arise in the same interval.

Whereas regulation and contingency reserves are deployed after unexpected outage event occurs, the design of FRC is straightforward to resolve the larger net load variation and uncertainty and to reduce the price spikes. FRC is less complex to implement, and it is a more favorable option from the production cost perspective. In addition, a transparent FRC price signal is obtained to provide effective economic incentives for resource flexibility. Although LAC is implemented in several ISO markets, it is not enough to ensure the ramping capability without a look-ahead dispatch (LAD). Although an LAD is capable of ensuring the ramping capability, the quality of an LAD solution is heavily influenced by the forecasts. What is more, the implementation of an LAD is more complex and extensive compared with that of an FRC. Detailed information and analysis on the comparison of FRC with other market options can be found in [18].

In recent years, ISOs have already experienced the ramping capacity shortage [18], and the research on improving FRC in power system operations has become very popular [18]-[25]. Reference [18] proposes an FRC model for the MISO market and derives the cost-effectiveness of the model using various numerical analyses, e.g., simulation on single-interval dispatch and time-coupled multi-interval dispatch. Reference [19] provides a mathematical formulation of ramping products that can be incorporated with the existing CAISO market rules. The optimal requirements for FRC are investigated in [20], where the reliable operation is emphasized in power systems with high penetration of renewable energies. The benefits of using wind power generation or electric vehicles as FRC providers are studied in [21], [22]. Reference [24] demonstrates the impacts of FRC products on stochastic economic dispatch, and shows that the market efficiency can be enhanced with FRC products. Reference [23] extends its research to [24], which focuses on the application of FRC products to unit commitment. In [24], the market solutions incorporating FRC products are compared with the benchmark results obtained from stochastic unit commitment. A comprehensive review on the modeling and implementation of FRC products is provided in [25].

However, to the authors' best knowledge, very few studies address the issues of ramping capacity shortage, especially when FRC is considered in unit commitment. In other words, the generation scheduling obtained from the conventional formulations cannot guarantee the availability of FRC even though the solution obtained does satisfy all the system constraints, including the FRC requirements as formulated in [24], [26]. The issue of ramping capacity shortage, which represents the case where the actual available FRC is less than the calculated FRC, might arise when the commitment status of generating units is arranged to be changed, i.e., the start-up of idle generator and shut-down of non-idle generator. The increasing penetration level of intermittent renewable generation makes thermal power plants start up and shut down more frequently [24]. It is therefore important to precisely formulate FRC in the unit commitment problem. We focus on the problem that, when a unit commitment decision made in a previous window has negative impacts on the following window, the ramping capacity shortage occurs in a series of rolling LAC windows. That is, this issue we raise arises only when commitment is changed. The congestion in transmission system can also be a cause for ramping capacity shortage but that is beyond the scope of this paper.

To the authors' best knowledge, the FRC formulations adopted in the CAISO and MISO markets are very close to the ones presented in [24]. It is noted that the CAISO FRC implementation [27] is different from the FRC conceptual design described in [24] that we take as the benchmark. However, we want to point out that the CAISO implementation model in [27] focuses on the real-time dispatch problem and does not consider the impacts from the unit commitment decisions. Therefore, like the FRC conceptual design described in [24], it is unclear that the CAISO implementation model described in [27] could resolve the issue we address in this paper, i. e., the ramping capacity shortage imposed by the unit commitment decisions in the LAC process. Because of the lack of the complete unit commitment and economic dispatch model from [27], for the sake of brevity, we reserve the analysis of a CAISO implementation model like that in [27] to future work.

There are some market procedures for the ISOs that contribute to the discussion of the issue of ramping capacity shortage raised in this paper. In the current procedures of an LAC in the ISO market, it is common that only commitment decisions are considered for implementation and units are not allowed to decommit (shut-down). This is an ad-hoc solution to prevent the shut-down of units in the real-time operation. Although it is effective from the perspective of reliability, it is not the most economical solution.

This paper aims to reveal the possibility of ramping capacity shortage in power system operation even though the explicit FRC constraints are satisfied at the scheduling stage. This issue of ramping capacity shortage exists in the formulation in the literature such as [24] and [26]. This paper proposes a new method to manage the issue of ramping capacity shortage in LAC when the flexible ramping product is considered and thereby can potentially improve the quality of LAC solutions. Moreover, we provide a formulation including the start-up and shut-down trajectories of slow-start generators in determining FRC. The proposed optimization problem is formulated as a mixed integer linear programming (MILP) model, which can be solved efficiently using off-the-shelf optimization software.

This paper focuses on the enhancement to the mathematical formulation of FRC and provides the proof of concept. The proposed formulation is designed to resolve the issue of ramping capacity shortage of FRC in the market and therefore requires less out-of-market corrections. Although the implementation is relevant with the practical details, it is beyond the scope of this paper.

The remainder of this paper is organized as follows. Section II presents the conventional unit commitment formulation with ramping product and addresses the issue of ramping capacity shortage. The proposed method is provided in Section III. Simulations based on the proposed method are presented in Section IV, and Section V summarizes the results of this work and draws conclusions.

II. Ramping Product in Unit Commitment

A. Conventional Unit Commitment Formulation with Ramping Product

In CAISO and MISO markets, two separate types of FRC, i.e., termed upward FRC and downward FRC, are co-optimized with energy and other ancillary services. The goal of upward FRC is to alleviate the upward ramping capability shortage, which occurs, for example, when the actual output of renewable generation is much smaller than anticipated. Besides, the downward FRC is secured in preparation for a sudden drop in net load. The requirements for the upward FRC and downward FRC, which are calculated just prior to $t=1$, i.e., the beginning point of running real-time LAC, are given as:

$$\begin{cases} UFRC_t = \max\{(NL_{t+1} - NL_t) + \alpha_t, 0\} \\ DFRC_t = \max\{(NL_t - NL_{t+1}) + \alpha_t, 0\} \end{cases} \quad t=1, 2, ..., T \tag{1}$$

The objective of the upward FRC $UFRC_t$ is to manage the net load variations between two successive intervals (i.e., expected change in net load) and the forecasting error in the next interval (i.e., unexpected change in net load). The net load forecasts are made and updated for each LAC run. The parameter α_t is used to represent the net load ramping error between two successive intervals resulted from the net load forecasting error. In CAISO markets, the historical data using statistical analysis are used to calculate α_t. The error distribution can also be assumed to follow the Gaussian model, and α_t can be set based on the standard deviation of the Gaussian model [20].

ISOs schedule the commitment status, generation dispatch, and ancillary service decisions after solving the day-ahead unit commitment problem. The objective of unit commitment is to minimize the operating costs while satisfying power system constraints (e.g., power balance, reserve provision, and transmission line flow limits) and generating unit constraints (e.g., the minimum and the maximum output limits, ramping rate limits, and the minimum on/off time limits). The proposed method in this paper can be applied to both day-ahead and real-time unit commitments. Except for FRC constraints expressed as (8) - (15), other reserve constraints such as regulation reserve, spinning reserve, supplemental reserve, and network constraints are also neglected to enable a clear interpretation of the obtained results. The mathematical formulation for real-time LAC with FRC constraints can be modeled as [24]:

$$\min \left\{0.25 \sum_{t \in \Omega_t} \sum_{g \in \Omega_g} (C_g^{NL} x_{gt} + C_g^{LP} p_{gt} + C_g^{SU} y_{gt} + LS_t \cdot MP)\right\} \quad (2)$$

s.t.

$$\sum_{g \in \Omega_g} p_{gt} = NL_t - LS_t \quad \forall t \quad (3)$$

$$P_g^{\min} x_{gt} \le p_{gt} \le \bar{p}_{gt} \le P_g^{\max} x_{gt} \quad \forall g, \forall t \quad (4)$$

$$\bar{p}_{gt} \le p_{g(t-1)} + RR_g \cdot x_{g(t-1)} + RR_g^{SU} \cdot (x_{gt} - x_{g(t-1)}) + P_g^{\max}(1 - x_{gt}) \quad \forall g, \forall t \quad (5)$$

$$\bar{p}_{gt} \le RR_g^{SD} \cdot (x_{gt} - x_{g(t+1)}) + P_g^{\max} x_{g(t+1)} \quad \forall g, \forall t \quad (6)$$

$$p_{g(t-1)} - p_{gt} \le RR_g \cdot x_{gt} + RR_g^{SD} \cdot (x_{g(t-1)} - x_{gt}) + P_g^{\max}(1 - x_{g(t-1)}) \quad \forall g, \forall t \quad (7)$$

$$P_g^{\min}(x_{gt} + x_{g(t+1)} - 1) \le UR_{gt} + p_{gt} \le \bar{p}_{g(t+1)} + P_g^{\max}(1 - x_{g(t+1)}) \quad \forall g, \forall t \quad (8)$$

$$P_g^{\min}(x_{gt} + x_{g(t+1)} - 1) \le -DR_{gt} + p_{gt} \le \bar{p}_{g(t+1)} + P_g^{\max}(1 - x_{g(t+1)}) \quad \forall g, \forall t \quad (9)$$

$$-RR_g \cdot x_{g(t+1)} - RR_g^{SD} \cdot (x_{gt} - x_{g(t+1)}) - P_g^{\max}(1 - x_{gt}) \le UR_{gt} \le RR_g \cdot x_{gt} + RR_g^{SU} \cdot (x_{g(t+1)} - x_{gt}) + P_g^{\max}(1 - x_{g(t+1)}) \quad \forall g, \forall t \quad (10)$$

$$-RR_g \cdot x_{gt} - RR_g^{SU} \cdot (x_{g(t+1)} - x_{gt}) - P_g^{\max}(1 - x_{g(t+1)}) \le DR_{gt} \le RR_g \cdot x_{g(t+1)} + RR_g^{SD} \cdot (x_{gt} - x_{g(t+1)}) + P_g^{\max}(1 - x_{gt}) \quad \forall g, \forall t \quad (11)$$

$$-P_g^{\max} x_{gt} + P_g^{\min} x_{g(t+1)} \le UR_{gt} \le P_g^{\max} x_{g(t+1)} \quad \forall g, \forall t \quad (12)$$

$$-P_g^{\max} x_{g(t+1)} \le DR_{gt} \le P_g^{\max} x_{gt} - P_g^{\min} x_{g(t+1)} \quad \forall g, \forall t \quad (13)$$

$$\sum_{g \in \Omega_g} UR_{gt} \ge UFRC_t \quad t = 1, 2, ..., T-1 \quad (14)$$

$$\sum_{g \in \Omega_g} DR_{gt} \ge DFRC_t \quad t = 1, 2, ..., T-1 \quad (15)$$

$$x_{g(t+1)} - x_{gt} = y_{g(t+1)} - z_{g(t+1)} \quad \forall g, \forall t \quad (16)$$

$$x_{gt}, y_{gt}, z_{gt} \in \{0, 1\} \quad \forall g, \forall t \quad (17)$$

$$\begin{cases} p_{gt} \ge 0 & \forall g, \forall t \\ \bar{p}_{gt} \ge 0 & \forall g, \forall t \end{cases} \quad (18)$$

$$LS_t \ge 0 \quad \forall t \quad (19)$$

The objective function (2) is defined to minimize the operating costs, which include generation costs, start-up costs, and the costs of load shedding. Equation (3) represents the power balance that should be maintained with load shedding. Equations (4) - (7) impose the technical limit of each generating unit. The contribution of each generating unit to FRC is restricted by (8) - (13). The constraints related to upward FRC limits are formulated as (8), (10), and (12), whereas downward FRC limits are enforced in (9), (11), and (13). The requirements for upward FRC and downward FRC are defined by (14) and (15), respectively, with FRC values determined using (1). The logical constraint for commitment states as well as start-up and shut-down variables is given in (16). The binary variables are represented in (17), and the non-negative constraint applied for p_{gt} and $\bar{p}_{gt}$ of generating units is given by (18). Note that neither the upward FRC nor downward FRC of generating units is included in (18). The load shedding during each interval is required to be non-negative in (19). If the trajectories of start-up and shut-down processes of generators are considered in a day-ahead optimization problem, (3) should be replaced with (20) [28].

$$\sum_{g \in \Omega_g} p_{gt} + \sum_{g \in \Omega_{gs}} \sum_{k=1}^{SU_g} P_g^{SU,k} y_{g(t-k+SU_g+1)} + \sum_{g \in \Omega_{gs}} \sum_{k=1}^{SD_g} P_g^{SD,k} z_{g(t-k+1)} = NL_t - LS_t \quad \forall t \quad (20)$$

B. Issue of Ramping Capacity Shortage

In order to show when and how the issue of ramping capacity shortage emerges, a simple test system that has four generators (G_1-G_4) is used. Because G_1 is the baseload generator, whose output is constant and other generators are fast-start units, the trajectories of start-up and shut-down processes are disregarded. In other words, the optimization problem expressed as (2)-(19) is solved. The same recursive approach utilized in [23] is adopted to emulate practical power system operation as follows.

1) Prior to $t=1$, the conditions are initialized, i.e., the dispatch target for the end of interval $t=0$ and the commitment decisions (on/off states) for $t=0, 1$.

2) At $t=1$, the multi-interval optimization problem is solved to find the on/off states at $t=2,3,4$ and the dispatch target for the end of interval $t=1,2,3,4$ with the boundary conditions from the first step.

3) At $t=2$, the multi-interval optimization problem is solved to find the on/off states for $t=3,4,5$ and the dispatch target for the end of interval $t=2,3,4,5$ with the boundary conditions from the second step.

4) At $t=3$, 4, ..., using the solutions from the previous steps as boundary conditions, the multi-interval optimization problem is solved. The target time intervals for the commitment decisions and dispatch targets are rolled forward one interval at a time.

Table I shows the solution of optimization problem at different determining time when the optimization problem is solved.

The generator data for the simple test system are tabulated in Table II. Table III shows the net load and ramping requirements for the simple test system when the forecasting of the LAC calculation is made at $t=1$, $t=2$, and $t=3$. It is assumed that the net load NL_t can vary in the range of ±30 MW, so α_t is set to be 30 MW. For example, $UFRC_t$ needed for the net load variations from $t=2$ to $t=3$ can be calculated at $t=2$ as $640\ \text{MW}-660\ \text{MW}+30\ \text{MW}=10\ \text{MW}$ according to (1). Likewise, it can be computed that $DFRC_t$ needed for the net load variations from $t=2$ to $t=3$ can be calculated at $t=2$ as 50 MW. Note that NL_t depends on when the forecasting is made. For example, NL_t at $t=3$ are 640 MW and 665 MW, respectively, when the forecasting for the LAC calculation is made at $t=2$ and $t=3$. It should be noted that when the net load forecasting is updated, all net load values in the scheduling horizon can be updated simultaneously. For simplicity, Table III shows the case where only the forecasting value at the initial interval in the scheduling horizon is updated.

TABLE I
SOLUTION OF OPTIMIZATION PROBLEM AT DIFFERENT DETERMINING TIME WHEN OPTIMIZATION PROBLEM IS CALCULATED

Time	Solution of optimization problem at different determining time									
	Prior $t=1$		At $t=1$		At $t=2$		At $t=3$		At $t=4$	
	Dispatch target	Commitment decision	Dispatch target	Commitment decision	Dispatch target	Commitment decision	Dispatch target	Commitment decision	Dispatch target	Commitment decision
$t=0$	Power	On/off	**<u>Power</u>**	**<u>On/off</u>**						
$t=1$		On/off	Power	**<u>On/off</u>**	**<u>Power</u>**	**<u>On/off</u>**				
$t=2$			Power	On/off	Power	**<u>On/off</u>**	**<u>Power</u>**	**<u>On/off</u>**		
$t=3$			Power	On/off	Power	On/off	Power	**<u>On/off</u>**	**<u>Power</u>**	**<u>On/off</u>**
$t=4$			Power	On/off	Power	On/off	Power	On/off	Power	**<u>On/off</u>**
$t=5$					Power	On/off	Power	On/off	Power	On/off
$t=6$							Power	On/off	Power	On/off
$t=7$									Power	On/off

Note: the bold underlined variables represent the ones solved at the previous determining time, which are used as boundary conditions, while other variables are to be optimized at the current determining time.

TABLE II
GENERATOR DATA FOR SIMPLE TEST SYSTEM

Generator	C_g^{LP} ($/MWh)	C_g^{NL} ($)	C_g^{SU} ($)	$P_g^{\max}$ (MW)	$P_g^{\min}$ (MW)	RR_g (MW per 15 min)	RR_g^{SU} (MW per 15 min)	RR_g^{DU} (MW per 15 min)
G_1	0	0	0	300	300	0	0	0
G_2	20	300	300	150	50	40	60	60
G_3	40	300	600	200	50	40	60	60
G_4	60	300	900	150	50	40	100	100

TABLE III
NET LOAD AND RAMPING REQUIREMENTS FOR SIMPLE SYSTEM

Time	Making forecasting at $t=1$			Making forecasting at $t=2$			Making forecasting at $t=3$		
	NL_t (MW)	$UFRC_t$ (MW)	$DFRC_t$ (MW)	NL_t (MW)	$UFRC_t$ (MW)	$DFRC_t$ (MW)	NL_t (MW)	$UFRC_t$ (MW)	$DFRC_t$ (MW)
$t=1$	690	0	60						
$t=2$	660	10	50	660	10	50			
$t=3$	640	10	50	640	10	50	665	0	75
$t=4$	620			620	0	60	620	0	60
$t=5$				590			590	10	50
$t=6$							570		

Table IV shows the optimal solution executed at $t=2$ based on the boundary condition obtained from the solution given at $t=1$. The optimal values of procured FRC are represented as continuous ranges if the constraints for FRC requirements are not binding, e. g., UR_{gt} and DR_{gt} of G_3 at $t=2$. Any combinations of the values meeting the requirements yield the same objective value.

The generator G_3 can ramp up as much as 40 MW from $t=2$ to $t=3$, therefore, the maximum ramping-up capability of the system at $t=2$ is 40 MW. However, it must be noted that the system cannot actually ramp up 40 MW until $t=3$. The actual "capable" upward FRC procured at $t=2$ is −10 MW. The reason for this miscalculation can be explained as follows.

In the LAC calculation excuted at $t=2$, when making the commitment decisions for $t=3$, the generator G_4 is determined to shut down at $t=3$, which results in zero power output of G_4 at $t=3$. The problem is that the 50 MW drop in the output of G_4 curtails the upward FRC because other generators should ramp up as much as 50 MW to make up for the output drop of G_4. The upward FRC contribution of G_4 at $t=2$ should be calculated as −50 MW. However, the obtained solution by solving (2)-(19) indicates that there is zero upward FRC contribution of G_4 at $t=2$. It is noted that although non-negativity constraint (18) excludes the FRC contributions of generating units, it is not enough to account for the "negative" effect of decommiting G_4 on upward FRC in the system. In order to clarify the "negative" effects of the generating units scheduled to be turned on or off, we define new variables NUR_{gt} and NDR_{gt} to represent the negative contributions of generator g to system FRC at t.

TABLE IV
OPTIMAL SOLUTION EXECUTED AT $t=2$

Time	Generator	x_{gt} (MW)	p_{gt} (MW)	UR_{gt} (MW)	DR_{gt} (MW)	Operating cost ($)
$t=2$	G_1	1	300	0	0	3325
	G_2	1	150	0	40	
	G_3	1	160	10-40	0-40	
	G_4	1	50	0	50	
$t=3$	G_1	1	300	0	0	2800
	G_2	1	150	0	10-40	
	G_3	1	190	10	10-40	
	G_4	1	0	0	0	
$t=4$	G_1	1	300	0	0	2600
	G_2	1	150	0	20-40	
	G_3	1	170	0-30	20-40	
	G_4	1	0	0	0	
$t=5$	G_1	1	300			2300
	G_2	0	150			
	G_3	0	140			
	G_4	0	0			

Table V shows the optimal solution results executed at $t=3$ when the net load is 665 MW, which lies in the range of 610 MW to 670 MW. As shown in Fig. 1, the dotted orange line gives the range of ramping capability scheduled at $t=2$, i. e., $UFRC_2=10$ MW and $DFRC_2=50$ MW. The range is $[660-50, 660+10]$MW. Even though the realized uncertainty is 25 MW, which is within the minimum and the maximum bounds, it can be observed that the involuntary load shedding occurs at $t=3$ due to the ramping capacity shortage. The operating costs at $t=3$ can be computed as \$55400 if the value of lost load (VOLL) is 9000 \$/MWh. We underline that the energy price at $t=3$ rises to VOLL because of the ramping capacity shortage. We will revisit this same example with the proposed formulation in Section IV.

III. Proposed Method

A. Additional Constraints for Start-up Generators and Shut-down Generators

We derive new constraints to consider the reduced FRC because of the generators to be turned on or off. We adopt the sign convention that a positive value of NUR_{gt} represents a negative contribution to upward FRC. Likewise, a new variable NDR_{gt} is defined to represent a negative effect on downward FRC. By adding the following formulas (21)-(26), we can resolve the ramping capacity shortage for the case where the start-up or shut-down is accomplished within one interval.

TABLE V
OPTIMAL SOLUTION EXECUTED AT $t=3$

Time	Generator	p_{gt} (MW)	Load shedding (MW)	Net load (MW)	Operating cost ($)
$t=3$	G_1	300	15	665 (realized)	55400
	G_2	150			
	G_3	200			
	G_4	0			
$t=4$	G_1	300	0	620	2600
	G_2	150			
	G_3	170			
	G_4	0			
$t=5$	G_1	300	0	590	2300
	G_2	150			
	G_3	140			
	G_4	0			
$t=6$	G_1	300	0	570	2100
	G_2	150			
	G_3	0			
	G_4	0			

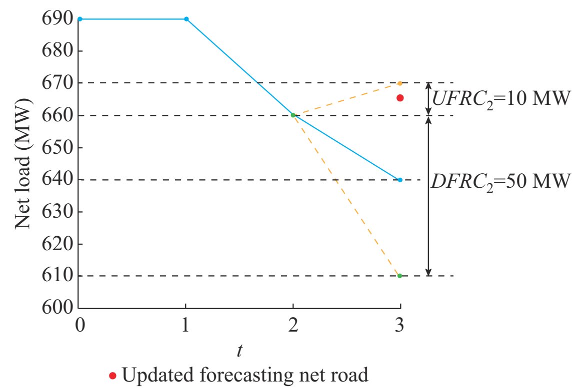

Fig. 1. Net load forecasting and FRC requirements at $t=2$.

Constraints (21)-(23) and (24)-(26) are applied for negative upward FRC and negative downward FRC, respectively. If generator g, which generates power above the minimum output level at t, is turned off at $t+1$, the subsidiary variable δ_{gt}^{SD} becomes zero while the binary variable $z_{g(t+1)}$ has a value of one. In this case, constraints (21)-(23) enforce that the negative upward FRC should be equal to p_{gt}. In all the other cases, i. e., a generator continues to generate power above the minimum power limit until $t+1$ or a unit is offline at t, $z_{g(t+1)}$ has a value of zero, which results in a zero negative effect on downward FRC ($NUR_{gt}=0$). Similarly, if the generator is scheduled to start up, the negative downward FRC has a nonzero value, in other words, it curtails the downward FRC of the system.

$$p_{gt}=NUR_{gt}+\delta_{gt}^{SD} \quad \forall g \in \Omega_{fg}, \forall t \tag{21}$$

$$P_g^{\min} z_{g(t+1)} \le NUR_{gt} \le P_g^{\max} z_{g(t+1)} \quad \forall g \in \Omega_{fg}, \forall t \tag{22}$$

$$0 \le \delta_{gt}^{SD} \le P_g^{\max}(1-z_{g(t+1)}) \quad \forall g \in \Omega_{fg}, \forall t \tag{23}$$

$$p_{gt}=NDR_{gt}+\delta_{gt}^{SU} \quad \forall g\in\Omega_{fg}, \forall t \tag{24}$$

$$P_g^{\min} y_{g(t+1)} \le NDR_{gt} \le P_g^{\max} y_{g(t+1)} \quad \forall g\in\Omega_{fg}, \forall t \tag{25}$$

$$0\le\delta_{gt}^{SU}\le P_g^{\max}(1-y_{g(t+1)}) \quad \forall g\in\Omega_{fg}, \forall t \tag{26}$$

The generators that complete the start-up and shut-down processes within one interval can be modeled as (21)-(26). However, if the start-up and shut-down procedures of a generator take longer than one interval, which we referred to as a slow-start generator, different formulas should be derived to reflect the start-up and shut-down trajectories. Figure 2 illustrates an example trajectory of a slow-start generator, whose shut-down process has a duration of two intervals. The generator is online from $t=1$ to $t=5$ and becomes offline from $t=6$. x_{gt} is equal to 1 from $t=1$ to $t=3$ and 0 otherwise. The slow-shut-down generator is scheduled to be turned off at $t=4$, and this generator is in the process of shut-down for two intervals, which leads the system operator to consider the reduced ramping capability from $t=3$ to $t=6$.

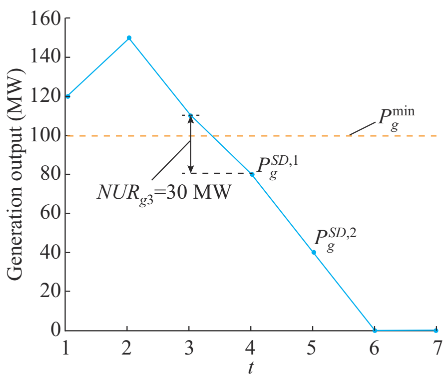

Fig. 2. Trajectory of slow-start generator g.

A negative upward FRC of the generator at $t=3$, which is the last period that the unit generates power above the minimum power limit, depends on the generation output of the unit itself (p_{g3}). The negative upward FRC is therefore a continuous variable, which can be computed as $p_{g3}-P_g^{SD,1}$. By employing the same technique used in formulating (21)-(26), namely by introducing auxiliary variables, the negative upward FRC can be formulated as (27)-(29). On the other hand, the negative upward FRCs at $t=4$ and $t=5$ have the fixed values, i.e., $P_g^{SD,1}-P_g^{SD,2}$ and $P_g^{SD,2}$, respectively, because the power outputs in the shut-down process are predefined as constant values. The formulation of negative upward FRC applied for the generator, whose duration of the shut-down process is SD_g, can be expressed as:

$$p_{gt}-P_g^{SD,1}x_{gt}=NUR_{gt}+\delta_{gt}^{SD}+P_g^{SD,1} \quad \forall g\in\Omega_{sg}, \forall t \tag{27}$$

$$(P_g^{\min}-P_g^{SD,1})z_{g(t+1)} \le NUR_{gt} \le (P_g^{\max}-P_g^{SD,1})z_{g(t+1)} \quad \forall g\in\Omega_{sg}, \forall t \tag{28}$$

$$0\le\delta_{gt}^{SD}+P_g^{SD,1}\le P_g^{\max}(1-z_{g(t+1)}) \quad \forall g\in\Omega_{sg}, \forall t \tag{29}$$

$$NUR_{gt}^{SD}=(P_g^{SD,1}-P_g^{SD,2})z_{gt}+(P_g^{SD,2}-P_g^{SD,3})z_{g(t-1)}+\dots+P_g^{SD,SD_g}z_{g(t-SD_g+1)} \quad \forall g\in\Omega_{sg}, \forall t \tag{30}$$

Similarly, the negative downward FRC can be formulated as:

$$p_{g(t+1)}-P_g^{SU,SU_g}x_{g(t+1)}=NDR_{gt}+\delta_{gt}^{SU}+P_g^{SU,SU_g} \quad \forall g\in\Omega_{sg}, \forall t \tag{31}$$

$$(P_g^{\min}-P_g^{SU,SU_g})y_{g(t+1)} \le NDR_{gt} \le (P_g^{\max}-P_g^{SU,SU_g})y_{g(t+1)} \quad \forall g\in\Omega_{sg}, \forall t \tag{32}$$

$$0\le\delta_{gt}^{SU}+P_g^{SU,SU_g}\le P_g^{\max}(1-y_{g(t+1)}) \quad \forall g\in\Omega_{sg}, \forall t \tag{33}$$

$$NDR_{gt}^{SU}=(P_g^{SU,SU_g}-P_g^{SU,SU_g-1})y_{g(t+2)}+(P_g^{SU,SU_g-1}-P_g^{SU,SU_g-2})\cdot y_{g(t+3)}+\dots+P_g^{SU,1}y_{g(t+SU_g+1)} \quad \forall g\in\Omega_{sg}, \forall t \tag{34}$$

B. Reformulation of Existing Constraint

In order to apply the proposed modeling of negative FRC, the upward and downward ramping requirement constraints (14) and (15) should be reformulated as (35) and (36), respectively.

$$\sum_{g\in\Omega_g} UR_{gt}-\sum_{g\in\Omega_g} NUR_{gt}-\sum_{g\in\Omega_{sg}} NUR_{gt}^{SD}\ge UFRC_t \quad \forall t \tag{35}$$

$$\sum_{g\in\Omega_g} DR_{gt}-\sum_{g\in\Omega_g} NDR_{gt}-\sum_{g\in\Omega_{sg}} NDR_{gt}^{SU}\ge DFRC_t \quad \forall t \tag{36}$$

By comparing (35) and (36) with (9) and (10), respectively, it should be noted that the optimal FRC requirements for the system are not modified, nor is it calculated in a different way. In this paper, we derive new formulations that enable the "capable" ramping capacity to be obtained if the optimal ramping requirements are given. Instead of using the Gaussian distribution of the forecasting error, the optimal requirements can be decided through various methods [20], and the proposed method can be suitably applied once the requirements are known in advance.

IV. Simulation Results

The proposed formulation is verified by using a simple test system and a modified IEEE 118-bus system. The same simple problem introduced in Section II-B is analyzed to show that the ramping capacity shortage can be avoided with the proposed method. In order to test the scalability of the proposed method, the day-ahead unit commitment problem is solved based on the IEEE 118-bus system, which includes wind power generators. All simulations in this paper are carried out on a personal computer with a 3.60 GHz Intel Core i5 8600K CPU, 16-GB RAM, and 64-bit operating system. The optimization solver GUROBI under GAMS is used to solve the problem, and the relative optimality tolerance is set to be 0.1%.

A. Simple Test System

The performance of the proposed method is evaluated on the simple test system introduced in Section II-B. The optimization problem that comprises the objective function (2) and constraints (3)-(19) and (21)-(26) is solved based on the same input data. Table VI compares the optimal solution executed at $t=2$ with the proposed method and the conventional method. Among the optimal solutions, the case where the procured FRC can be maximized is listed in Table VI. The changes in the unit commitment results executed at $t=2$ are listed as bold underlined data. Due to the new constraints to deal with the issue of ramping capacity shortage, G_4 stays online until $t=3$ with the proposed method while the commitment schedules of other units are the same as those of the conventional method.

TABLE VI
OPTIMAL SOLUTIONS EXECUTED AT $t=2$ WITH DIFFERENT METHODS

Time	Method	Generator	x_{gt}	P_{gt} (MW)	UR_{gt} (MW)	DR_{gt} (MW)	Operating cost ($)
$t=2$	Proposed method	G_1	1	300	0	0	3325
		G_2	1	150	0	40	
		G_3	1	160	40	40	
		G_4	1	50	40	0	
	Conventional method	G_1	1	300	0	0	3325
		G_2	1	150	0	40	
		G_3	1	160	40	40	
		G_4	1	50	0	50	
$t=3$	Proposed method	G_1	1	300	0	0	**3225**
		G_2	1	130	20	40	
		G_3	1	160	40	40	
		G_4	**1**	50	0	50	
	Conventional method	G_1	1	300	0	0	**2800**
		G_2	1	150	0	40	
		G_3	1	190	10	40	
		G_4	**0**	0	0	0	
$t=4$	Proposed method	G_1	1	300	0	0	2600
		G_2	1	150	0	20	
		G_3	1	170	30	40	
		G_4	0	0	0	0	
	Conventional method	G_1	1	300	0	0	2600
		G_2	1	150	0	40	
		G_3	1	170	30	40	
		G_4	0	0	0	0	
$t=5$	Proposed method	G_1	1	300			2300
		G_2	1	150			
		G_3	1	140			
		G_4	0	0			
	Conventional method	G_1	1	300			2300
		G_2	1	150			
		G_3	1	140			
		G_4	0	0			

When the net load at $t=3$ is 665 MW, which is the same load level as the example in Section II-B, the optimal solution executed at $t=3$ with proposed method can be obtained as summarized in Table VII. As can be observed in Table VII, no involuntary load shedding occurs at $t=3$ due to the sufficient and reliable ramping capability procured at $t=2$. It should be noted that the load shedding may take place if the unit commitment is solved with the conventional method, as shown in Table V. Also, it should be noted that G_3 sets the energy price at $t=3$ with the proposed method. The operating cost in Table VII is significantly lower than that in Table V.

TABLE VII
OPTIMAL SOLUTION EXECUTED AT $t=3$ WITH PROPOSED METHOD

Time	Generator	P_{gt} (MW)	Load shedding (MW)	Net load (MW)	Operating cost ($)
$t=2$	G_1	300	15	665 (realized)	3375
	G_2	150			
	G_3	165			
	G_4	50			
$t=3$	G_1	300	0	620	2975
	G_2	140			
	G_3	130			
	G_4	50			
$t=4$	G_1	300	0	590	2300
	G_2	150			
	G_3	140			
	G_4	0			
$t=5$	G_1	300	0	570	2100
	G_2	150			
	G_3	120			
	G_4	0			

B. Modified IEEE 118-bus System

The proposed method is applied to a more realistic problem with the modified IEEE 118-bus system, which has 54 slow-start generators. The total installed wind power is assumed to be 50% of peak load. The specific system data are taken from [28].

The day-ahead FRC requirements are determined based on estimates of the real-time ramping needs, which will not be known until the operating day. In this paper, the day-ahead FRC requirements are computed similar to the real-time case, as expressed in (1). The hourly variations of the net load are considered, and the hour-ahead forecasting error distributions are used instead of using the 15-min-ahead forecasting error. It is assumed that the forecasting errors of both the demand and the wind power generation follow a normal distribution with zero mean. The standard deviation for the forecasting error of demand is set to be 1% of the forecasting demand, and the standard deviation for the forecasting error of wind power generation is set to be 4% of the installed wind power [29].

In order to compare the proposed method with conventional method, we generate 2500 scenarios using Monte Carlo simulation. The performance of each method is analyzed using the following procedure [30].

Step 1: solve the hourly unit commitment problem of the 54 generators during the 24-hour periods with the central forecasting net load. The conventional method uses (2), (4) - (19), (20), while the proposed method uses (2), (4) - (19), (20) - (36). The minimum on/off time limits, which are not shown here, are also considered when solving the problem.

Step 2: select one of the generated scenarios.

Step 3: evaluate the performances of both the conventional method and the proposed method with the selected scenario. The online generators are re-dispatched to cover the realized uncertainty, and the operating cost and load shedding cost are calculated. If the load shedding is required to satisfy the power balance constraint, this is penalized by a cost in the objective function.

Step 4: go to *Step 3* using another scenario and repeat the process until the last scenario (the 2500th scenario). Compute and save the average values of the generation cost and the load shedding cost.

Step 5: make comparison of the results. The expected operating cost is defined as the sum of the average generation cost and the average load shedding cost.

Table VIII and Fig. 3 summarize the expected operating costs of the proposed method and the conventional method. The additional FRC requirements to cover forecasting error α_t are set to be 2.8, 3.0, and 3.5 times the standard deviation of the forecasting error of net load. We define the ratio of α_t to the standard deviation as β_t, so we have $\beta_t = 2.8$, 3.0, and 3.5. As can be observed in Fig. 3, the generation cost increases with the increasing ramping requirements. If the procured FRC is not enough, the involuntary load shedding events occur even with the proposed method. However, it should be noted that the proposed method can ensure a reliable operation for any deviation which lies within the target bounds. With the conventional method, we have found some cases, similar to the toy example, where the ISO needs to resort to load shedding even though the deviation of the forecasting value is within the minimum and the maximum error bounds.

TABLE VIII
COMPONENTS OF EXPECTED OPERATING COSTS WITH PROPOSED AND CONVENTIONAL METHODS

β_t	Conventional method			Proposed method		
	Generation cost ($)	Load shedding cost ($)	Total operating cost ($)	Generation cost ($)	Load shedding cost ($)	Total operating cost ($)
2.8	1177783	181174	1358957	1181970	103408	1285378
3.0	1180206	96536	1276742	1185369	64224	1249593
3.5	1187610	60094	1247703	1193311	11199	1204510

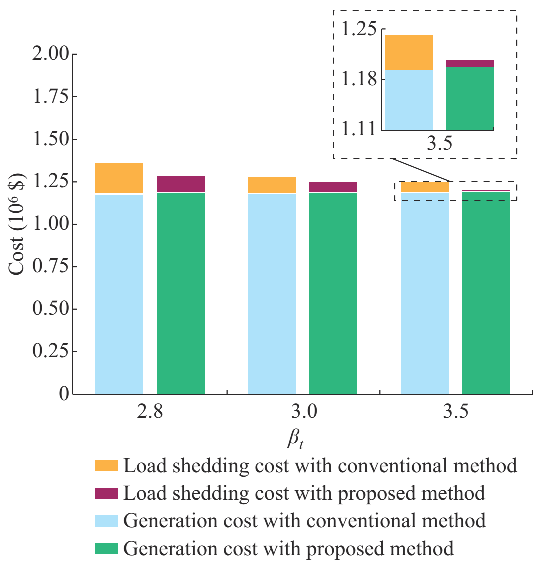

Fig. 3. Evaluation results of proposed and conventional methods in 2500 validation scenarios for IEEE 118-bus system.

The average computational time required to solve the problem is listed in Table IX.

TABLE IX
AVERAGE COMPUTATIONAL TIME WITH PROPOSED AND CONVENTIONAL METHODS

β_t	Computational time (s)	
	Proposed method	Conventional method
2.8	947	745
3.0	1107	702
3.5	898	831

The additional variables and constraints in an MILP model may increase the computational burden, as can be observed from Table IX. However, the increased computational burden can be reduced using the following tighter formulations:

$$P_g^{\min} z_{g(t+1)} \le NUR_{gt} \le RR_G^{SD} z_{g(t+1)} \quad \forall g \in \Omega_{fg}, \forall t \tag{37}$$

$$P_g^{\min} y_{g(t+1)} \le NDR_{gt} \le RR_G^{SU} y_{g(t+1)} \quad \forall g \in \Omega_{fg}, \forall t \tag{38}$$

If RR_g^{SD} is smaller than $P_g^{\max}$, the constraint (37) is a tighter formulation that can be used to replace (22). Similarly, (25) can be replaced by the new formulation (38). These new tight formulations can improve the linear programming relaxation bounds, and it can speed up the branch-and-bound algorithm. The computational time based on tighter formulations (37) and (38) is shown in Table X.

TABLE X
AVERAGE COMPUTATIONAL TIME WITH CONVENTIONAL METHODS AND PROPOSED FORMULATIONS

β_t	Computational time (s)		
	Conventional methods	Proposed formulation	Proposed tight formulation
2.5	21.32	27.92	19.81
2.8	18.75	21.57	11.32
3.0	20.17	21.73	20.66
3.3	17.51	29.80	21.19
3.5	22.23	18.85	17.50

The problems are solved only for seven intervals to test the computational time for a shorter scheduling horizon problem e.g., real-time unit commitment. As confirmed in the results, the computational burden of the proposed method is comparable to that of the conventional one. It should be noted that the operating costs with the proposed tight formulation are exactly the same as the operating costs for the proposed formulation.

V. Conclusion

In this paper, we propose a new formulation of ramping product that can ensure the deliverability of the procured FRC. The proposed ramping product design in the existing unit commitment problem has been demonstrated with examples to show the improvement on the system reliability. A method considering the trajectories of the start-up and shutdown processes of the generator in the determination of FRC is also developed. Newly-derived approaches have been formulated as an MILP such that the problem can be easily solved with an available MILP solver.

Simulation results show that a generation scheduling, based on conventional method, might yield unreliable operations. We have found cases where the procured FRC is insufficient, even if the deviation of the forecasting values is within the anticipated bounds, which leads to load shedding. With the proposed method, an ISO can guarantee the reliable operations if the optimal requirements for FRC are properly predefined.

Although the focus of this paper is on the proof of concept, we would like to address several limitations due to the lack of realistic system data. One major contribution of this paper is to identify and demonstrate the ramping capability shortage in particular conditions and provide an enhanced FRC formulation to resolve the issue. Nevertheless, depending on the operating conditions, the impact of the proposed method on a real system will be different. The magnitude of the overall benefits of the proposed method can be further investigated in a large-scale realistic system. The proposed method increases the number of decision variables, and the additional variables might increase the computational burden for an ISO. The trade-off between the improved economic benefits and the increased computational burden can be further studied in a realistic system.

The specifications of ramping products and the FRC requirements may differ from case to case. Practically, the probability distribution function of historical net load forecasting errors is used to determine the ramping requirement. However, we believe that the proposed method can generally be applied to other scenarios that focus on the design of the ramping products.

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