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Three-Level Co-optimization Model for Generation Scheduling of Integrated Energy and Regulation Market

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***Abstract*— This paper proposes a three-level co-optimization model for determining energy production and regulation reserve schedule in a day-ahead market by minimizing the total cost of unit commitment, generation dispatch, frequency regulation and performance. The unscented transformation and historical profiles are used to generate scenarios for modelling the fluctuations of intermittent renewable and stochastic loads at different time scales. Through detailed modelling and simulation of generation dispatch and frequency regulation, the determined generation schedule can have sufficient reserve capacity and adequate response speed to deal with the renewable and load variations occurred between shorter dispatching and regulating intervals, as well as longer scheduling intervals. Numerical results on a 5-bus sample system are given to demonstrate the effectiveness of proposed method.**

***Keywords*— co-optimization; energy productin; frequency regulation; frequency regulation preformance; generation dispatch; regulation reserve; unit comitment**

I. INTRODUCTION

Independent system operators are responsible for maintaining an instantaneous and continuous balance between supply and demand of power system through managing the energy and reserve markets, including day-ahead market and real-time market. According to the forecasted or historical load and non-dispatchable generation profiles for next day, the commitment schedule of dispatchable generation units for next 24 hours are determined through solving a security-constrained unit commitment problem. This task is complicated by the increased presence of distributed energy resources and the continuing improvements on market regulations. The unpredictable nature of renewable energy sources leads to greater fluctuations in the amount of generated power available [1]. Meanwhile, the renewable may demonstrate different characteristics in term of fluctuation magnitudes and frequency if its data sets are collected at different sampling rates. A unit commitment schedule, that conventionally determined based on renewable and load profiles generated at longer time scale might not be optimal when implemented in real time due to the unit's technical constraints such as ramping rates and min up/down times. In addition, the market regulatory rules have also required the generation units rewarded by their services that they have actually provided or achieved in real time [2]. Without taking the real-time renewable and load fluctuations into account in some manners, the gaps or deviations between day-ahead schedules and real-time dispatch and control hardly be mitigated. There are many approaches available for solving the stochastic unit commitment problems, specially targeting for co-optimization of energy and reserve markets, such as [3]-[9]. Most of these approaches are focused on hourly generation and load variations, i.e. variations at scheduling intervals.

In light of this, this paper proposes a three-level co-optimization model for determining the optimal energy production and regulation reserve schedule for generation units by minimizing the total cost of unit commitment, generation dispatch, frequency regulation and performance. The unscented transformation method is used to generate sample uncertainty scenario for renewable and load at scheduling intervals, and typical/historical renewable generation and load profiles are used to simulate the load and renewable fluctuations at dispatching and regulating intervals. Through detailed modelling of unit commitment, generation dispatch and frequency regulation in the process of co-optimization, the gaps or deviations between day-ahead schedules and real-time dispatch and control implementation will be reduced, and thus the system efficiency can be improved and the profits for generation companies can be increased.

II. THE PROPOSED METHOD

The co-optimization of the energy production and regulation reserve services in a day-ahead market is proposed to be achieved through a three-level optimization process as shown in Fig. 1, including unit commitment, generation dispatch, and frequency regulation.

The generation units are divided into dispatchable units that can perform energy production and regulation reserve tasks, and non-dispatchable generation units, such as renewable units that can only be used as constant powers. Some dispatchable units may do not have frequency regulation capability, so can only be used for energy production. Based on the needs of system power balance, renewable spillage and load shedding may be used but at certain penalty charges.

A. Uncertainty Modeling

The uncertainty of renewable and load at scheduling intervals are modelled through a set of sample uncertainty scenarios that generated based on unscented transformation technique [10].

Assumed $\mathbf{P}_{\mathrm{h}}$ is the vector of active powers contributed or consumed by renewable sources or load demands at scheduling interval h, and follows the Gaussian distribution with mean $\widehat{\mathbf{P}}_{\mathrm{h}}$ and covariance $\mathbf{Q}_{\mathrm{h}}$:

$$\mathbf{P}_{\mathrm{h}} \sim \mathrm{N}(\widehat{\mathbf{P}}_{\mathrm{h}}, \mathbf{Q}_{\mathrm{h}}) \tag{1a}$$

A set of scenarios, $\widetilde{\mathbf{P}}_{\mathbf{h}}$ is created by using a set of $(2n+1)$ sample points:

$$\widetilde{\mathbf{P}}_{\mathrm{h}} = [\widehat{\mathbf{P}}_{\mathrm{h}} \quad \cdots \quad \widehat{\mathbf{P}}_{\mathrm{h}}] + \sqrt{n+\lambda}\left[0 \quad \sqrt{\mathbf{Q}_{\mathrm{h}}} \quad -\sqrt{\mathbf{Q}_{\mathrm{h}}}\right] \tag{1b}$$

where, n is the total number of renewable sources and load demands, $\lambda = \alpha^2(n+\kappa) - n$, α and κ are the parameters that determine the spread of the sigma points around. For example, we set: $\alpha = 1.0$, $\kappa = 1$. The square root of the covariance matrix, $\sqrt{\mathbf{Q}_h}$ can be solved using the Cholesky factorization method. Using For any variable Y_h associated with $\mathbf{P}_h$ according to $Y_h = f(\mathbf{P}_h)$, its mean vector, $\widehat{Y}_h$ can be determined based on the sample points of $\widetilde{\mathbf{P}}_h$:

$$\widehat{Y}_h = \sum_{k=0}^{2n} W_{h_k} f\left(\widetilde{P}_{h_k}\right) \tag{1c}$$

where W_{h_k} is the weight factor for uncertainty scenario h_k, $W_{h_0} = \lambda/(n+\lambda)$, and $W_{h_k} = 0.5/(n+\lambda)$ if k>0.

Dividing the sample points with corresponding forecasted means as shown in (1b), we can get a set of scale factors for each uncertainty scenario. Those scaling factors are solely defined by the renewable and load covariance, and can be used to derive the values for uncertainty scenario based on renewable and load forecasts.

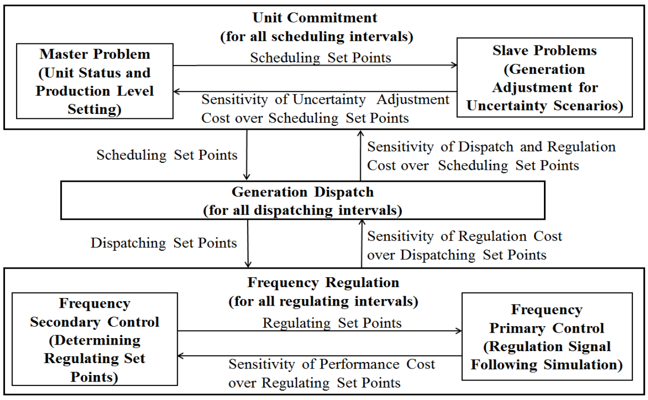


Fig.1. Three-level co-optimization model for generation schedulin

For a given scheduling interval h, the generation output of renewable r and power demand of load d under uncertainty scenario h_k, P_{rh_k} and P_{rh_k}can be determined as:

$$P_{rh_k} = P_{rh}\alpha_{rh_k} \tag{2a}$$

$$P_{dh_k} = P_{dh}\alpha_{dh_k} \tag{2b}$$

where P_{rh} and P_{dh}, and α_{rh_k} and α_{dh_k} are the forecasted generations and demands, and scaling factors for renewable r and load d respectively.

The renewable and load variations at dispatching and regulating intervals are determined based on the corresponding variation factors defined based on the historical profiles.

For a dispatching interval m within scheduling interval h and uncertainty scenario h_k, the renewable generation and load demand, P_{rh_km} and P_{dh_km} are determined as:

$$P_{rh_km} = P_{rh_k}\left(1 + \beta_{rh,m}\right) \tag{3b}$$

$$P_{dh_km} = P_{dh_k}\left(1 + \beta_{dhm}\right) \tag{3b}$$

where $\beta_{rh,m}$ and β_{dhm} are the renewable and load variation factors to represent the variations at dispatching interval m around average renewable generation and load demand at scheduling level h.

Similarly, the renewable generation and load demand at regulating interval s within dispatching interval m of uncertainty scenario h_k of scheduling interval h, P_{rh_kms} and P_{dh_kms} are determined as:

$$P_{rh_kms} = P_{rh_k}(1 + \beta_{rhm} + \beta_{rhms}) \tag{4a}$$

$$P_{dh_kms} = P_{dh_k}(1 + \beta_{dhm} + \beta_{dhms}) \tag{4b}$$

where β_{rhms} and β_{dhms} are the renewable and load variation factors for regulating inteval s.

B. Unit Commitment

The first level of co-optimization is to determine the unit commitment schedule under forecasted base scenarios and sample uncertainty scenarios for renewable productions and load consumptions. The schedule defines the unit commitment statues and scheduling set points for all dispatchable units, renewable spillages for all renewable units, and load shedding for all loads in each scheduling interval. This level is solved through a master problem and a set of slave problems. The master problem is used to determine the on/off status of dispatchable units, and base scheduling set points for each generation unit. The slave problem is used to verify whether the determined unit schedule can withstand certain uncertainty scenarios for each scheduling interval, and determine the sensitives of the generation adjustment cost over scheduling set points given by the determined commitment schedule. The master and slave problems are iteratively solved to obtain a unit commitment schedule with minimum commitment, dispatch and regulation cost.

The master problem in the first level can be formulated as:

$$\text{Minimize} \quad c^{UC} = \sum_{h=1}^{H}\Big\{\sum_{g=1}^{G}\big(C_{gh}^{SU}\Delta u_{gh}^{+} + C_{gh}^{SD}\Delta u_{gh}^{-} + C_{gh}^{FIX}u_{gh} + C_{gh}^{VAX}p_{gh} + C_{gh}^{RU}\Delta p_{gh}^{+} + C_{gh}^{RD}\Delta p_{gh}^{-}\big) + \sum_{r=1}^{R} C_{rh}^{S}p_{rh}^{S} + \sum_{d=1}^{D} C_{dh}^{S}p_{dh}^{S}\Big\} + c^{UA} \tag{5a}$$

Subject to:

$$\sum_{g=1}^{G} p_{gh} + \sum_{r=1}^{R}(P_{rh} - p_{rh}^{S}) = \sum_{d=1}^{D}(P_{dh} - p_{dh}^{S}) \quad \forall h \tag{5b}$$

$$\sum_{g=1}^{G} r_{gh}^{+} \ge R_h^{+}\sum_{d=1}^{D}(P_{dh} - p_{dh}^{S}) \quad \forall h \tag{5c}$$

$$\sum_{g=1}^{G} r_{gh}^{-} \ge R_h^{-}\sum_{d=1}^{D}(P_{dh} - p_{dh}^{S}) \quad \forall h \tag{5d}$$

$$\sum_{g=1}^{G}\left(u_{g(h-1)}\overline{RU_g} + \Delta u_{gh}^{+}\overline{SU_g}\right) \ge RV_h^{+}\sum_{d=1}^{D}(P_{dh} - p_{dh}^{S}) \quad \forall h \tag{5e}$$

$$\sum_{g=1}^{G}\left(u_{gh}\overline{RD_g} + \Delta u_{gh}^{-}\overline{SD_g}\right) \ge RV_h^{-}\sum_{d=1}^{D}(P_{dh} - p_{dh}^{S}) \quad \forall h \tag{5f}$$

$$\sum_{h=1}^{H}\sum_{k=1}^{K_h} W_{h_k}\left[c_{h_k}^{UA(0)} + \sum_{g=1}^{G}\frac{\partial c_{h_k}^{UA}}{\partial p_{gh}^{(0)}}\left(p_{gh} - p_{gh}^{(0)}\right)\right] \le c^{UA} \tag{5g}$$

$$u_{gh} - u_{g(h-1)} - \Delta u_{gh}^{+} + \Delta u_{gh}^{-} = 0 \quad \forall g,h \tag{5h}$$

$$p_{gh} - p_{g(h-1)} - \Delta p_{gh}^{+} + \Delta p_{gh}^{-} = 0 \quad \forall g,h \tag{5i}$$

$$p_{gh} + r_{gh}^{+} \le u_{gh}\overline{P_g} \quad \forall g,h \tag{5j}$$

$$p_{gh} - r_{gh}^{-} \ge u_{gh}\underline{P_g} \quad \forall g,h \tag{5k}$$

$$p_{gh} - p_{g(h-1)} + r_{gh}^{+} \le u_{g(h-1)}\overline{RU_g} + \Delta u_{gh}^{+}\overline{SU_g} \quad \forall g,h \tag{5l}$$

$$p_{g(h-1)} - p_{gh} + r_{gh}^{-} \le u_{gh}\overline{RD_g} + \Delta u_{gh}^{-}\overline{SD_g} \quad \forall g,h \tag{5m}$$

$$\sum_{t=h-UT_g+1}^{h}\Delta u_{gt}^{+} \le u_{gh} \quad \forall g,h \tag{5n}$$

$$\sum_{t=h-DT_g+1}^{h}\Delta u_{gt}^{-} \le 1 - u_{gh} \quad \forall g,h \tag{5o}$$

$$p_{rh}^{S} \le P_{rh} \quad \forall r,h \tag{5p}$$

$$p_{dh}^{S} \le P_{dh} \quad \forall d,h \tag{5q}$$

$$f_{lh} = \sum_{g=1}^{G}\pi_{lg}p_{gh} + \sum_{r=1}^{R}\pi_{lr}(P_{rh} - p_{rh}^{S}) - \sum_{d=1}^{D}\pi_{ld}(P_{dh} - p_{dh}^{S}) \quad \forall l \in L^{UC}, h \tag{5r}$$

$$-\overline{F_l} \le f_{lh} \le \overline{F_l} \quad \forall l \in L^{UC}, h \tag{5s}$$

where, H and $K_h$are total numbers of scheduling intervals, and sample uncertainty scenarios at scheduling interval h. G is the total numbers of dispatchable generation units. u_{gh}, Δu_{gh}^{+} andΔu_{gh}^{-} are binary variables to indicate the unit committed, started-up and shut-down status. p_{gh}, Δp_{gh}^{+} andΔp_{gh}^{-},r_{gh}^{+} andr_{gh}^{-} are the unit scheduling set point for base case, incremental upward/downward generation changes between two consecutive scheduling intervals, and the ramp-up and ramp-down reserve contributions for generation unit g. C_{gh}^{SU}, C_{gh}^{SD}, C_{gh}^{FIX}, C_{gh}^{VAX}, C_{gh}^{RU} and C_{gh}^{RD} are the start-up cost, shut-down cost, fixed non-load cost, per unit variable cost, per unit ramp-up and ramp-down costs for unit *g*. $\overline{RU_g}$ and $\overline{RD_g}$, $\overline{SU_g}$ and $\overline{SD_g}$, $\overline{P_g}$ and $\underline{P_g}$, UT_g and DT_g are the upward and downward ramping rate thresholds, start-up and shut-down ramping rate thresholds, maximum and minimal generation outputs, and minimum up and down times for unit g. *R* is the total numbers of renewable generation units. p_{rh}^S and C_{rh}^S are the renewable spillage, and per unit spillage cost for renewable *r*. *D* is the total numbers of loads. p_{dh}^S and C_{dh}^S are the load shedding, and per unit shedding cost for load *d*. L^{UC} is the set of overload transmission lines. f_{lh} and $\overline{F_l}$ are the power flows on line *l* at scheduling interval *h* and its power flow capacity. π_{lg}, π_{lr} and π_{ld} are the allocation factors of dispatchable generator *g*, renewable *r* and load *d* to the power flow on transmission line *l*, which can be determined using DC load flow formulations. R_h^+ and R_h^-, RV_h^+ and RV_h^- are the required ratios of upward and downward reserves, and regulation speeds over system net loads. $c_{h_k}^{UA}$ and $\partial c_{h_k}^{UA}/\partial p_{gh}$ are the additional scheduling adjustment, dispatch and regulation cost for scenario h_k and its sensitivities over base scheduling set points. $p_{gh}^{(0)}$, $c_{h_k}^{UA(0)}$ and $\partial c_{h_k}^{UA}/\partial p_{gh}^{(0)}$ are corresponding values determined at last iteration or given initially.

As expressed in (5a), the objective of the master problem is to minimize the total cost related to commitment schedule for the entire operation cycle, c^{UC}. It includes the start-up/shut-down cost, the fixed non-load cost, the variable cost for base scheduling set point, the ramp up/ down costs between consecutive scheduling intervals, the spillage cost of intermittent renewable, the cost for load shedding, and the additional scheduling adjustment, dispatch and regulation cost for each sample uncertainty scenario (including the base case), c^{UA} which are considered as a liner function of scheduling set points using sensitivities of associated cost over base set points.

The master problem is constrained by system-wide constraints, (5b)-(5f), device-wise constraints (5h)-(5s). The system wide constraints include power balance equations, system upward/down regulation capacities and speed requirements. The regulation capacities and speeds required for handling the maximum fluctuations of renewable and loads at various sampling intervals. The transmission line security requirements are expressed as power flow equations and limits for the lines. To reduce the computation burden, only equations associated with overload lines are included, and the iterative solution is used until there is no overload existing. The master problem is related to slave problems through (4g).

With the determined scheduling set points and unit status, the slave problem for simulating the system operation under a given uncertainty scenario h_k can be formulated as:

$$\text{Minimize } c_{h_k}^{UA} = \sum_{g=1}^{G}\left(C_{gh}^{RU}\Delta p_{gh_k}^{+} + C_{gh}^{RD}\Delta p_{gh_k}^{-} + C_{gh}^{RU}\Delta p_{g(h_k-h)}^{+} + C_{gh}^{RD}\Delta p_{g(h_k-h)}^{-}\right) + \sum_{r=1}^{R} C_{rh}^{S}\left(p_{rh_k}^{S} - p_{rh}^{S(0)}\right) + \sum_{d=1}^{D} C_{dh}^{S}\left(p_{dh_k}^{S} - p_{dh}^{S(0)}\right) + c_{h_k}^{GD} \quad (6a)$$

Subject to:

$$\sum_{g=1}^{G} p_{gh_k} + \sum_{r=1}^{R}\left(P_{rh_k} - p_{rh_k}^{S}\right) = \sum_{d=1}^{D}\left(P_{dh_k} - p_{dh_k}^{S}\right) \quad \forall g \quad (6b)$$

$$c_{h_k}^{GD(0)} + \sum_{g=1}^{G} \frac{\partial c_{h_k}^{GD}}{\partial p_{gh_k}^{(0)}}\left(p_{gh_k} - p_{gh_k}^{(0)}\right) \le c_{h_k}^{GD} \quad \forall g \quad (6c)$$

$$p_{gh_k} = p_{gh}^{(0)} + \Delta p_{g(h_k-h)}^{+} - \Delta p_{g(h_k-h)}^{-} \quad \forall g \quad (6d)$$

$$p_{gh_k} = p_{g(h-1)}^{(0)} + \Delta p_{gh_k}^{+} + \Delta p_{gh_k}^{-} \quad \forall g \quad (6e)$$

$$p_{gh}^{(0)} + \Delta p_{g(h_k-h)}^{+} \le u_{gh}^{(0)}\overline{P_g} \quad \forall g \quad (6f)$$

$$p_{gh}^{(0)} - \Delta p_{g(h_k-h)}^{-} \ge u_{gh}^{(0)}\underline{P_g} \quad \forall g \quad (6g)$$

$$\Delta p_{gh_k}^{+} \le u_{g(h-1)}^{(0)}\overline{RU_g} + \Delta u_{gh}^{+(0)}\overline{SU_g} \quad \forall g \quad (6h)$$

$$\Delta p_{gh_k}^{-} \le u_{gh}^{(0)}\overline{RD_g} + \Delta u_{gh}^{-(0)}\overline{SD_g} \quad \forall g \quad (6i)$$

$$p_{rh_k}^{S} \le P_{rh_k} \quad \forall r \quad (6j)$$

$$p_{dh_k}^{S} \le P_{dh_k} \quad \forall d \quad (6k)$$

$$f_{lh_k} = \sum_{g=1}^{G}\pi_{lg}p_{gh_k} + \sum_{r=1}^{R}\pi_{lr}\left(P_{rh_k} - p_{rh_k}^{S}\right) - \sum_{d=1}^{D}\pi_{ld}\left(P_{dh_k} - p_{dh_k}^{S}\right) \quad \forall l \in L^{UA} \quad (6l)$$

$$-\overline{F_l} \le f_{lh_k} \le \overline{F_l} \quad \forall l \in L^{UA} \quad (6m)$$

where L^{UA} is the set of overload lines under scenario h_k. p_{gh_k}, $\Delta p_{gh_k}^{+}$ and $\Delta p_{gh_k}^{-}$, $\Delta p_{g(h_k-h)}^{+}$ and $\Delta p_{g(h_k-h)}^{-}$ are the generation output under scenario h_k, the output changes between the uncertainty scenario and the base case at previous scheduling interval (*h*-1), p_{gh_k} and $p_{g(h-1)}$, the output changes between uncertainty scenario h_k and the set point at corresponding scheduling interval *h*, p_{gh_k} and p_{gh}. $c_{h_k}^{GD}$ and $\partial c_{h_k}^{GD}/\partial p_{gh_k}$ are the additional dispatch and regulation cost for scenario h_k and its sensitivities over scheduling set points for the scenario. $u_{gh}^{(0)}$, $\Delta u_{gh}^{+(0)}$, $\Delta u_{gh}^{-(0)}$, $p_{gh_k}^{(0)}$, $c_{h_k}^{GD(0)}$ and $\partial c_{h_k}^{GD}/\partial p_{gh_k}^{(0)}$ are corresponding values determined at last iteration or given initially. $p_{rh_k}^{S}$, $p_{dh_k}^{S}$ and f_{lh_k} are the renewable spillage for renewable r, load shedding for load d and power flow on line l under scenario h_k.

The objective of the slave problem at the first level is to minimize the total generation adjustment cost for the scenario, $c_{h_k}^{UA}$. Besides the weighted dispatch and regulation costs for each scenario, the uncertainty adjustment cost includes the weighted cost related to the generation output changes between the previous base set point and current uncertainty scenario set point, and the current base set point and current uncertainty scenario set point. It also includes the cost changes for renewable spillage and load shedding between the base values determined by the master problem and the values for the current uncertainty scenario.

The slave problem of the first level is linked with problems at second and third levels through (6c). The sensitives of generation adjustment cost over base scheduling set points that used in the master problem can be determined as:

$$\frac{\partial c_{h_k}^{UA}}{\partial p_{gh}^{(0)}} = \alpha_{p_{gh_k}} - \beta_{\Delta p_{g(h_k-h)}^{+}} + \gamma_{\Delta p_{g(h_k-h)}^{-}} \quad (7)$$

$\alpha_{p_{gh_k}}$, $\beta_{\Delta p_{g(h_k-h)}^{+}}$ and $\gamma_{\Delta p_{g(h_k-h)}^{-}}$ are the dual variables of (6d), (6f) and (6g) respectively.

C. Generation Dispatch

The second level of co-optimization is to determine the generation dispatch plans for all dispatch intervals within a given scheduling interval, including the dispatching set points for dispatchable units, renewable spillage and load shedding if needed. The impact of frequency regulation is taken into account through the sensitivities of regulation cost over dispatching set points of dispatchable units. In this level, the determined unit commitment scheme is checked against dispatch operation scenarios to verify whether the unit commitment schedule satisfying the load and renewable fluctuations that occur at a short timescale, i.e. dispatching interval. The historical renewable generation and load profiles are used to create dispatching scenarios along with the renewable and load forecasts within next operation cycle.

The generation dispatch problem can be formulated as:

$$\text{Minimize} \quad c_{h_k}^{GD} = \sum_{m=1}^{M_h} \sum_{g=1}^{G} \left(C_{gm}^{RU} \Delta p_{g(m-h_k)}^{+} + C_{g,m}^{RD} \Delta p_{g(m-h_k)}^{-} + C_{gm}^{RU} \Delta p_{gh_km}^{+} + C_{gm}^{RD} \Delta p_{gh_km}^{-} \right) + \sum_{r=1}^{R} C_{rm}^{S} \left(p_{rh_km}^{S} - p_{rh_k}^{S(0)} \right) + \sum_{d=1}^{D} C_{dm}^{S} \left(p_{dh_km}^{S} - p_{dh_k}^{S(0)} \right) + c_{h_k}^{FR} \quad (8a)$$

Subject to:

$$\sum_{g=1}^{G} p_{gh_km} + \sum_{r=1}^{R} \left(P_{rh_km} - p_{rh_km}^{S} \right) = \sum_{d=1}^{D} \left(P_{dh_km} - p_{dh_km}^{S} \right) \ \forall m \quad (8b)$$

$$\sum_{m=1}^{M_h} \left[c_{h_km}^{FR(0)} + \sum_{g=1}^{G} \frac{\partial c_{h_km}^{FR}}{\partial p_{gh_km}^{(0)}} \left(p_{gh_km} - p_{gh_km}^{(0)} \right) \right] \le c_{h_k}^{FR} \quad (8c)$$

$$p_{gh_km} = p_{gh_k}^{(0)} + \Delta p_{g(m-h_k)}^{+} - \Delta p_{g(m-h_k)}^{-} \quad \forall g, m \quad (8d)$$

$$p_{gh_km} = p_{gh_k(m-1)} + \Delta p_{gh_km}^{+} + \Delta p_{gh_km}^{-} \quad \forall g, m \quad (8e)$$

$$p_{gh_k}^{(0)} + \Delta p_{g(m-h_k)}^{+} \le u_{gh}^{(0)} \overline{P_g} \quad \forall g, m \quad (8f)$$

$$p_{gh_k}^{(0)} - \Delta p_{g(m-h_k)}^{-} \ge u_{gh}^{(0)} \underline{P_g} \quad \forall g, m \quad (8g)$$

$$\Delta p_{gh_km}^{+} \le \tau_{h-m} \left(u_{g(h-1)}^{(0)} \overline{RU_g} + \Delta u_{gh}^{+(0)} \overline{SU_g} \right) \ \forall g, m \quad (8h)$$

$$\Delta p_{gh_km}^{-} \le \tau_{h-m} \left(u_{gh}^{(0)} \overline{RD_g} + \Delta u_{gh}^{-(0)} \overline{SD_g} \right) \quad \forall g, m \quad (8i)$$

$$p_{rh_km}^{S} \le P_{rh_k} \quad \forall r, m \quad (8j)$$

$$p_{dh_km}^{S} \le P_{dh_k} \quad \forall d, m \quad (8k)$$

$$f_{lh_km} = \sum_{g=1}^{G} \pi_{lg} p_{gh_km} + \sum_{r=1}^{R} \pi_{lr} \left(P_{rh_km} - p_{rh_km}^{S} \right) - \sum_{d=1}^{D} \pi_{ld} \left(P_{dh_km} - p_{dh_km}^{S} \right) \quad \forall m, l \in L^{GD} \quad (8l)$$

$$-\overline{F_l} \le f_{lh_km} \le \overline{F_l} \quad \forall m, l \in L^{GD} \quad (8m)$$

where, M_h is total number of dispatching intervals of interval *h*. p_{gh_km}, $\Delta p_{g(m-h_k)}^{+}$ and $\Delta p_{g(m-h_k)}^{-}$, $\Delta p_{gh_km}^{+}$ and $\Delta p_{gh_km}^{-}$ are the dispatching set point, the unit output differences between the scheduling set point $p_{gh_k}^{(0)}$ and the dispatching set point, the unit output changes between two consecutive dispatching intervals, *m* and (*m*-1), p_{gh_km} and $p_{gh_k(m-1)}$. The per unit ramp up/down costs and renewable spillage and load shedding costs can be determined based on corresponding values per scheduling interval and pre-determined conversion factors. $c_{h_k}^{FR}$ is the cost related to frequency regulation for the scheduling interval *h*, and expressed using the sensitivity of cost related to dispatching interval, $c_{h_km}^{FR(0)}$ over generation output at the dispatching interval, p_{gh_km}. L^{GD} is the set of overload lines. τ_{h-m} is the ratio of length of dispatching interval over length of scheduling interval, and used to convert ramping thresholds from per scheduling interval to per dispatching interval. $p_{rh_km}^{S}$, $p_{dh_km}^{S}$ and f_{lh_km} are the renewable spillage for renewable *r*, load shedding for load *d* and power flow on line *l* at dispatch interval *m* under scenario h_k.

The objective of generation dispatch is to minimize the total cost related to generation dispatch and regulation, $c_{h_k}^{GD}$ as shown in (8a). The cost includes the additional cost incurred by the generation output changes between the scheduling set point and dispatching set point, and the set points between two consecutive dispatching intervals. It is also included the cost changes for renewable spillages and load shedding between the determined values for the scheduling interval and the values for the dispatching interval.

The sensitivities of generation dispatch and regulation cost over scheduling set points are determined as:

$$\frac{\partial c_{h_k}^{GD}}{\partial p_{gh_k}^{(0)}} = \sum_{m=1}^{M_h} \left(\alpha_{p_{gh_km}} - \beta_{\Delta p_{g(m-h_k)}^{+}} + \gamma_{\Delta p_{g(m-h_k)}^{-}} \right) \quad (9)$$

$\alpha_{p_{gh_km}}$, $\beta_{\Delta p_{g(m-h_k)}^{+}}$ and $\gamma_{\Delta p_{g(m-h_k)}^{-}}$ are the dual variables of (8d),(8f) and (8g) respectively.

D. Frequency Regulation

The third level of co-optimization is to determine the generation frequency regulation schemes to maintain qualified system frequency in each regulating interval. In this level, the frequency regulation is used to simulate the power system to deal with fluctuations in load and renewable that occur at a much faster timescale, i.e. regulating interval. The historical profile of load and generation for this timescale are used to determine the expected frequency regulation and performance cost for each dispatchable unit. The generation regulation setting points (determined by secondary frequency control) are first determined based on load and renewable variations and frequency requirements for each regulating interval. The performance for generation units to follow the regulation setting points (implemented by primary frequency control) are then measured by the sum of deviation of setting points and actual achieved mechanical outputs of generation units.

The frequency regulation is formulated as:

$$\text{Minimize} \ c_{h_km}^{FR} = \sum_{s=1}^{S_{hm}} \left[\sum_{g=1}^{G} \left(C_{gs}^{RU} \Delta p_{gh_k(s-m)}^{+} + C_{gs}^{RD} \Delta p_{gh_k(s-m)}^{-} + C_{gs}^{RU} \Delta p_{gh_ks}^{+} + C_{gs}^{RD} \Delta p_{gh_ks}^{-} \right) + \sum_{r=1}^{R} C_{rs}^{S} \left(p_{rh_kms}^{S} - p_{rh_km}^{S(0)} \right) + \sum_{d=1}^{D} C_{ds}^{S} \left(p_{dh_kms}^{S} - p_{dh_km}^{S(0)} \right) + c_{h_km}^{PR} \right] \quad (10a)$$

Subject to:

$$-K_D \Delta \overline{f} \sum_{d=1}^{D} p_{dh_kms}^{S} \le \sum_{g=1}^{G} \left(p_{gh_kms}^{C} + \frac{\Delta f_{h_kms}^{+} - \Delta f_{h_kms}^{-}}{DR_g} \right) + \sum_{r=1}^{R} \left(P_{rh_kms} - p_{rh_km}^{S} \right) - \sum_{d=1}^{D} \left[\left(1 + K_D \Delta f_{h_kms}^{+} - K_D \Delta f_{h_kms}^{-} \right) P_{dh_kms} - p_{dh_km}^{S} \right] \le K_D \Delta \overline{f} \sum_{d=1}^{D} p_{dh_kms}^{S} \ \forall g, s \ (10b)$$

$$\Delta f_{h_kms}^{+} - \Delta f_{h_kms}^{-} \le \Delta \overline{f} \quad \forall s \quad (10c)$$

$$\sum_{s=1}^{S_{hm}} \left[c_{h_kms}^{PR(0)} + \sum_{g=1}^{G} \frac{\partial c_{h_kms}^{PR}}{\partial p_{gh_kms}^{C(0)}} \left(p_{gh_kms}^{C} - p_{gh_kms}^{C(0)} \right) \right] \le c_{h_km}^{PR} \quad (10d)$$

$$p_{gh_kms} = p_{gh_km}^{(0)} + \Delta p_{gh_k(s-m)}^{+} - \Delta p_{gh_k(s-m)}^{-} \ \forall g, s \ (10e)$$

$$p_{gh_kms}^{C} = p_{gh_km(s-1)}^{C} + \Delta p_{gh_kms}^{C+} + \Delta p_{gh_kms}^{C-} \ \forall g, s \ (10f)$$

$$p_{gh_kms}^{C} - u_{g,h}^{(0)} \frac{\Delta f_{h_kms}^{+} - \Delta f_{h_kms}^{-}}{DR_g} = p_{gh_kms} \quad \forall g, s \quad (10g)$$

$$p_{gh_km}^{(0)} + \Delta p_{gh_k(s-m)}^{+} \le u_{gh}^{(0)} \overline{P_g} \quad \forall g, s \quad (10h)$$

$$p_{gh_km}^{(0)} - \Delta p_{gh_k(s-m)}^{-} \ge u_{gh}^{(0)} \underline{P_g} \quad \forall g, s \quad (10i)$$

$$\Delta p_{gh_kms}^{C+} \le \tau_{h-s} \left(u_{g(h-1)}^{(0)} \overline{RU_g} + \Delta u_{gh}^{+(0)} \overline{SU_g} \right) \quad \forall g, s \quad (10j)$$

$$\Delta p_{gh_kms}^{C-} \le \tau_{h-s} \left(u_{gh}^{(0)} \overline{RD_g} + \Delta u_{gh}^{-(0)} \overline{SD_g} \right) \ \forall g, s \ (10k)$$

$$p_{rh_kms}^{S} \le P_{rh_kms} \quad \forall r, s \quad (10l)$$

$$p_{dh_kms}^{S} \le P_{dh_kms} \quad \forall d, s \quad (10m)$$

$$f_{lh_kms} = \sum_{g=1}^{G} \pi_{lg} p_{gh_kms} + \sum_{r=1}^{R} \pi_{lr} \left(P_{rh_kms} - p_{rh_kms}^{S} \right) - \sum_{d=1}^{D} \pi_{ld} \left(P_{dh_kms} - p_{dh_kms}^{S} \right) \quad \forall l \in L^{FR}, s \quad (10n)$$

$$-\overline{F_l} \le f_{lh_kms} \le \overline{F_l} \quad \forall l \in L^{FR}, s \quad (10o)$$

where, S_{hm} is total number of regulating intervals of dispatching interval *m* within scheduling interval *h*. p_{gh_kms}, $\Delta p_{gh_k(s-m)}^{+}$ and $\Delta p_{gh_k(s-m)}^{-}$, and $\Delta p_{gh_kms}^{C+}$ and $\Delta p_{gh_kms}^{C-}$ are the generation output at regulating interval s, the upward and downward output differences between the dispatching and regulating intervals, p_{gh_kms} and $p^{(0)}_{gh_km}$, and the upward and downward regulating set point (i.e. generation control command) changes between two consecutive regulating intervals, s and (s-1), $p^C_{gh_kms}$ and $p^C_{gh_km(s-1)}$. L^{FR} is the overload line set. τ_{h-s} is the ratio of length of regulation interval over length of scheduling interval, and used to convert ramping thresholds from per scheduling interval to per regulation interval. Δf_{h_kms} and $\Delta\overline{f}$ are the system frequency deviation (away from system rated frequency), and its allowed threshold. K_D is system load frequency sensitivity coefficient, and $\mathrm{DR_g}$ is the generation unit droop (in MW/HZ). $p^S_{rh_kms}$, $p^S_{dh_kms}$ and f_{lh_kms} are the renewable spillage for renewable r, load shedding for load d and power flow on line l at regulation interval s.

The objective for frequency regulation is to minimize the total cost related to frequency regulation, $c^{FR}_{h_km}$. It includes the cost related to mismatch between the dispatching set point and generation output at the regulating interval, and regulation set point changes between two consecutive regulating intervals, and cost changes related to renewable spillage and load shedding. It also includes the additional cost related to frequency regulation performance, $c^{PR}_{h_km}$.

The costs related to primary frequency regulation performance for all regulating intervals in the dispatching interval m and scheduling interval h, $c^{PR}_{h_km}$ is expressed as a linear function of generation set point at the regulation interval using the sensitivity of related cost for the regulation interval over generation set point at the regulation interval, $\partial c^{PR}_{h_kms}/\partial p^{C(0)}_{gh_kms}$.

The constraints for frequency regulation include power balance requirement with frequency changes for interval s (10b), and generation droop control equation (10g).

The cost for primary frequency regulation performance is defined as:

$$c^{PR}_{h_kms} = \sum_{g=1}^{G}\left(C^{UPMC}_S \max\{0, p^M_{gh_kms} - p^C_{gh_kms}\} + C^{DPMC}_S \max\{0, p^C_{gh_kms} - p^M_{gh_kms}\}\right) \quad (11)$$

C^{UPMC}_S and C^{DPMC}_S are per unit upward/downward mismatch costs between frequency regulation setting points, $p^C_{gh_kms}$ and generation mechanical outputs, $p^M_{gh_kms}$. The sensitivities of primary frequency regulation cost over dispatching set points are determined as:

$$\frac{\partial c^{FR}_{h_km}}{\partial p^{(0)}_{gh_km}} = \sum_{s=1}^{S_{hm}}\left(\alpha_{p_{gh_kms}} - \beta_{\Delta p^+_{gh_k(s-m)}} + \gamma_{\Delta p^-_{gh_k(s-m)}}\right) \quad (12)$$

$\alpha_{p_{gh_kms}}$, $\beta_{\Delta p^+_{gh_k(s-m)}}$ and $\gamma_{\Delta p^-_{ggh_k(s-m)}}$ are the dual variables of (10e),(10h) and (10i) respectively.

The ability of a generator in following the frequency regulation signal depends on its technology and physical characteristics. Without loss of generality, we consider a governor-turbine control model for each generator where a speed governor senses the changes in its power command set points, i.e., the frequency regulation set points, $p^C_{h_kms}(t)$ and converts them into valve actions. A turbine then converts the changes in valve positions into changes in mechanical power output, i.e., generation signal $p^M_{h_kms}(t)$. The relationship between the incremental changes of mechanical output and control signal, $\Delta p^M_{h_kms}(t)$ and $\Delta p^C_{h_kms}(t)$ is described as:

$$\left(1 + T^G_g \frac{d}{dt}\right)\left(1 + T^T_g \frac{d}{dt}\right)\Delta p^M_{h_kms}(t) = \Delta p^C_{h_kms}(t) \quad (13)$$

For a given regulating interval s, the mechanical output of generator g can be determined as:

$$p^M_{h_kms} = p^C_{h_km0} + \sum_{i=1}^{s}\left(p^C_{h_kmi} - p^C_{h_km(i-1)}\right)\delta(i)\, u[t - \tau_s(i-1)] \quad (14a)$$

$$\delta(i) = \left[1 - \left(T^G_g e^{-\frac{\tau_s(s-i+1)}{T^G_g}} - T^T_g e^{-\frac{\tau_s(s-i+1)}{T^T_g}}\right)/\left(T^G_g - T^T_g\right)\right] \quad (14b)$$

$u(t)$ is a unit step function, $\delta(i)$ is the generation regulation achieving ratio for regulation interval i. The sensitivity of frequency regulation performance cost over regulation setting points is determined according to:

$$\frac{\partial c^{PR}_{h_kms}}{\partial p^C_{h_kms}} = \delta(s)\left[C^{UPMC}_S \max\left(0, \frac{p^M_{gh_kms} - p^C_{gh_kms}}{|p^M_{gh_kms} - p^C_{gh_kms}|}\right) - C^{DPMC}_S \max\left(0, \frac{p^C_{gh_kms} - p^M_{gh_kms}}{|p^C_{gh_kms} - p^M_{gh_kms}|}\right)\right] \quad (15)$$

III. Numerical Examples

The proposed method has been tested on a 5-bus system as shown in Fig. 2. The system has 2 dispatchable units (located at Bus-1, and Bus-2), 1 non-dispatchable PV unit (located at Bus-5), 2 loads (located at Bus-3 and Bus-4), and 5 lines. All lines have same impedance and capacity as 0.01+j0.1 p.u. and 50 MW respectively. Fig. 2 also shows the maximal and minimal outputs of generation units, and the base power consumption/generation for the loads/renewables. The scheduling, dispatching and regulating intervals are set as 1 hour, 15 minutes and 15 seconds respectively.

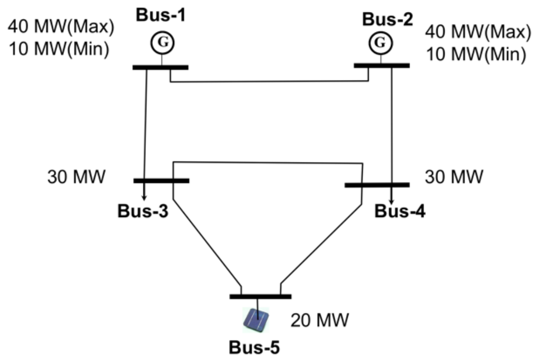


Fig.2. 5-Bus test system that used in this paper

Fig. 3 gives the typical daily PV generation and load profiles sampled once per 15 seconds, and the values at vertical axis are the ratios of actual values with corresponding base values. Those profiles are used to derive the dispatching and regulating variation factors for renewable and loads. The standard deviations of hourly renewable and load variation are assumed to be 10% of their hourly average values. Those standard deviations are used to generate the covariance matrix and define the scaling factors for sample uncertainty scenarios.

The parameters for generation units are given in Table I. Both generation units have been running for 10 hours.

The test results are summarized in Table II. The required upward/downward regulation reserve capacity and speed ratios are 10%, and the allowed maximum frequency deviation is 1.0Hz. The system load frequency sensitivity coefficient is 5%/HZ. There are two cases in the table. The generation schedule of Case I is determined by ignoring the impacts of generation dispatch and frequency regulation. In comparison, the impacts generation dispatch and frequency regulation are modelled when determining the generation schedule for Case II. The determined daily schedule of generation energy production and regulation reserve for Case II are depicted in Fig. 4.

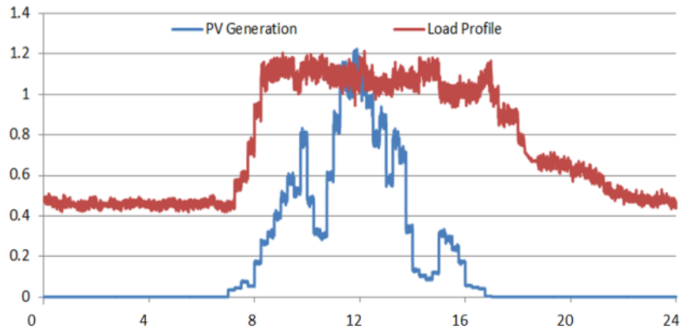
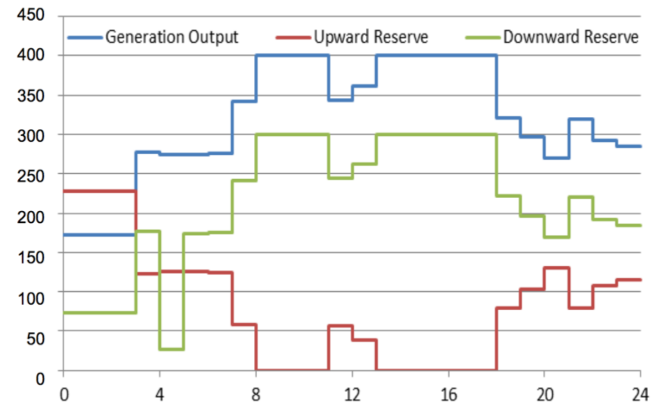


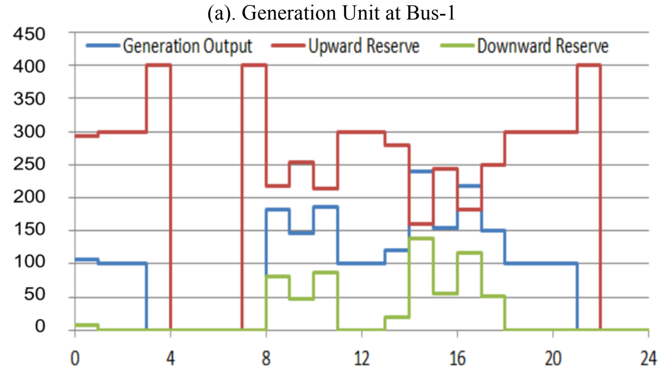
Fig. 3. Renewable and Load Profiles

Table I. Generation Unit Parameters

Attribute	Generation Unit Bus		Attribute	Generation Unit Bus	
	Bus-1	***Bus-2***		***Bus-1***	***Bus-2***
Ramping Rate (MW/min)	1.33	3.33	Shut-down costs (k$)	0.2	0.1
Start-up/shut-down ramping rate (MW/min)	2.66	6.66	Fixed cots(k$/h)	0.2	0.1
Governor time constant (s)	1	0.5	Variable cots (k$/MWh)	0.02	0.04
Turbine time constant (s)	12	6	Ramping Costs (k$/MW/h)	0.02	0.01
Droop	10%	10%	Regulation performance cost (k$/MWh)	0.01	0.02
Start-up costs (k$)	0.4	0.2	min up/down time(h)	4/2	2/1



(a). Generation Unit at Bus-1



(b). Generation Unit at Bus-2

Fig. 4. Generation schedule for energy production and regulation reserve

Table II. Test Cases and Results

Case	Unit On Schedule (Hrs)	Cost Contributions (k$)			
		Unit Commitment	***Generation Dispatch***	***Frequency Regulation***	***Total***
I	Bus-1: 0 -23 Bus-2:0-3,7-20	37.26	0.47	3.82	41.6
II	Bus-1: 0 -23 Bus-2: 0-3,7-21	37.27	0.46	1.94	39.7

Compared with Case I, Case II has committed the generation unit at Bus-2 operating one more hour, but has less additional frequency regulation cost at third level. It is shown that the total cost of Cast II is 1.9 k$ (i.e. 4.75%) less than Case I. This result has preliminarily demonstrated the advantages for using three-level co-optimization model.

IV. CONCULUSIONS

This paper has proposed a three-level co-optimization model for generation scheduling in a day-ahead market. The impacts of renewable and load fluctuations at three different time scales have been taken into account. Through detailed modelling of unit commitment, generation dispatch and frequency regulation in the process of co-optimization, the gaps or deviations between day-ahead schedules and real-time dispatch and control have been effectively mitigated, and thus the system efficiency can be improved and the profits for generation companies can be maximized. The preliminary results have demonstrated the effectiveness of the proposed method.

Future work may include developing more efficient algorithm, testing on practical systems, and more detailed modelling of unit start-up, and shut-down process.

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