Impacts of High Penetration Wind Generation and Demand Response on LMPs in Day-Ahead Market

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***Abstract*—Environmental issues in power systems operation lead to a rapid deployment of renewable wind generations. Wind generation is usually given the highest priority by assigning zero or negative energy bidding prices in the day-ahead power market, in order to effectively utilize available wind energy. However, when congestions occur, negative wind bidding prices would aggravate negative locational marginal prices (LMPs) in certain locations. The paper determines the proper amount of demand response (DR) load to be shifted from peak hours to off peaks under the Independent System Operator's (ISO) direct load control, for alleviating transmission congestions and enhancing the utilization of wind generation. The proposed mixed-integer linear programming (MILP) model is to minimize the total operation cost while incorporating explicit LMP formulations and non-negative LMP requirements into the network-constrained unit commitment (NCUC) problem, which are derived from the Karush-Kuhn-Tucker (KKT) optimality conditions of the economic dispatch (ED) problem. Numerical case studies illustrate the effectiveness of the proposed model.**

***Index Terms*—Demand response, KKT, load shifting, LMP, NCUC, wind generation.**

Nomenclature

Variables:

d, i, l, n	Index of loads/thermal units/branches/buses.
$D_{d,t}$	Load d at time t after load shifting is applied.
$\underline{\Delta D_{d,t}}$	Downward demand shift of load d at time t.
$\overline{\Delta D_{d,t}}$	Upward demand shift of load d at time t.
ΔD_{sum}	Total load shift.
$I_{i,t}$	ON/OFF status of unit i at time t, is equal to 0 when the unit is OFF, and 1 when it is ON.
k	Index of segments.
$Ip_{i,t}^{k}$	Binary variable to indicate if the output of thermal unit i is located in segment k at time t
$\text{LMP}_{n,t}$	Locational marginal price of bus n at time t.
$\text{OR}_{i,t}$	Operating reserve of thermal unit i at time t.
$P_{i,t}$	Dispatch of thermal unit i at time t.
$P_{i,t}^{k}$	Dispatch at segment k of unit i at time t.
$P_{w,t}$	Dispatch of wind generator w at time t.
$\Delta p_{i,t}^{k}$	Value of $p_{i,t}$ beyond lower limit of segment k.
PL_{l}	Real power flow of branch l.
$SD_{i,t}$	Shutdown cost of thermal unit i at time t.
$SR_{i,t}$	Spinning reserve of thermal unit i at time t.
$SU_{i,t}$	Startup cost of thermal unit i at time t.
t, τ	Index of time periods.
w	Index of wind units.
$y_{i,t}$	Startup indicator of thermal unit i at time t.
$z_{i,t}$	Shutdown indicator of thermal unit i at time t.
$z_{\max i,t} z_{\min i,t}$	Binding status on the maximum/ minimum capacity limit of thermal unit i at time t.
$z_{RUi,t}$, $z_{RDi,t}$	Binding status on the ramping up/down constraint of thermal unit i at time t.
$z_{\max w,t}$	Binding status on the maximum capacity limit of wind unit w at time t.
$z_{\text{seg}i,t}^{k}$	Binding status on the capacity upper limit of segment k of thermal unit i at time t.
$zu_{l,1,t}, zu_{l,2,t}$	Network constraint binding status of branch l at time t.
λ_t	Dual variable related to the system power balance constraint at time t.
δ	Dual variable related to the power level constraint of individual generators.
$\mu_{l,1,t}, \mu_{l,2,t}$	Dual variables related to the network constraint of branch l at time t.

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Constants:

c_i^k — Bidding price of segment k of thermal unit i.

$\overline{\Delta D_{d,\max}}$ — Maximum upward load shifting capability of load d.

$\underline{\Delta D_{d,\max}}$ — Maximum down load shifting capability of load d.

$D_{\text{initial},d,t}$ — Base demand of load d at time t.

DT_i — Number of hours thermal unit i must be initially OFF due to minimum OFF time limit.

$e_{n,i}$ — Parameter to indicate whether thermal unit i is connected to bus n.

$e_{n,w}$ — Parameter to indicate whether wind unit w is connected to bus n.

$I_{i,0}$ — Initial ON/OFF status of thermal unit i.

K — Total number of segments.

L — Total number of branches.

$\mathbf{Kd}$ — Bus-load incidence matrix.

$\mathbf{Kp}$ — Bus-generator incidence matrix.

MSR_i — Maximum sustained ramping rate of unit i.

NB, ND, NT — Total number of buses/loads/thermal units.

NG, NW — Total number of thermal/wind units.

NL_i — No-load cost of thermal unit i.

$P_{\min,i}$ — Minimum output level of thermal unit i.

$P_{\max,i}$ — Maximum output level of thermal unit i.

$P_{\text{forecast},w,t}$ — Forecast wind generation of wind unit w at time t.

$\mathbf{PL_{max}}$ — Power flow capacity limits of lines.

Q — A large positive number.

QSC_i — Quick start capability of thermal unit i.

RD_i, RU_i — Ramping down/up rate of thermal unit i.

Ro_t, Rs_t — System operating/spinning reserve requirement at time t.

sd_i, su_i — Shutdown/startup cost of thermal unit i.

$\mathbf{SF}$ — Shifting factor matrix.

Step_i — The segment MW limit of thermal unit i.

T_i^{on}, T_i^{off} — Minimum ON/OFF time of thermal unit i.

UT_i — Number of hours thermal unit i must be initially ON due to its minimum ON time limit.

X_{i0}^{on}, X_{i0}^{off} — Initial ON/OFF hours of thermal unit i.

ε — A very small positive number.

ω — Load shifting penalty cost.

I. Introduction

CLIMATE changes, global warming in particular, have required environmental issues to be seriously considered in power systems operation. As an alternative to traditional fossil fuels, renewable wind generation is rapidly deployed, which is plentiful, widely distributed, and environmentally friendly. Over the past five years, the global average annual growth in new wind generation installations is 27.6%. The total nameplate capacity of wind generation throughout the world was over 238 GW by the end of 2011 [1], [2]. In order to fully utilize available wind generation and dispatch less conventional generating units, one common method is to give wind generation the highest priority by assigning zero or negative energy bidding prices when clearing day-ahead markets [3], [4].

However, uncertainty and variability of wind generation bring additional challenges. [5] showed that the probabilistic wind power forecast would play an important role in guiding wind energy trading decisions in the day-ahead market. [6] assessed the impact of an increasing wind power penetration on locational marginal prices (LMPs), while considering actual wind generation as negative random loads. It indicated that inherent uncertain characteristics of wind power will considerably increase the standard deviation of LMPs.

LMP is the additional cost when the load increases at a certain bus [7], [8]. LMP can be calculated by dual variables of the nodal power balance constraints in the economic dispatch (ED) problem. LMPs may change significantly with respect to the changes in the binding/unbinding status of generation and transmission limitations, as well as discrete critical load levels. Wind farms are usually far from load centers, but the corresponding transmission capability expansion has been marginal [9]. The rapid deployment of wind generations with relative lag of transmission investments would aggravate network congestions and induce more negative LMPs.

Negative LMPs usually happen at periods with excessive generation, especially at off-peak hours when plentiful wind generation is available but load is relatively low. Fig. 1 shows typical daily wind and load patterns in a control area of CAISO [10]. Peak loads usually occur in the afternoon while most wind generation is available during the midnight. It is therefore evident that negative LMPs may occur in high wind penetration areas, when excessive wind generation cannot be fully utilized due to transmission congestions and off-peak loads. ISOs/RTOs have been facing with negative LMPs almost every day. For instance, [11] shows that negative LMPs occur in Electric Reliability Council of Texas (ERCOT), even ERCOT mandates curtailing and oversees more wind curtailment than any other region in America. [11] showed that the western zone of the ERCOT, where the majority of the wind is located in, had negative electricity prices for more than 20% of the time in April 2008. Negative LMPs may benefit consumers in short term, but would be harmful to power systems in the long run and prevent the fully utilization of available wind

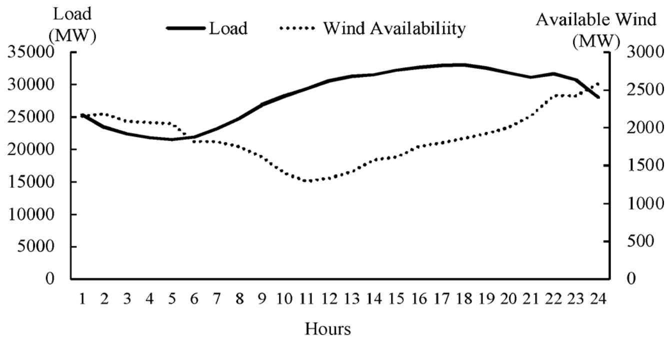

Fig. 1. System load curve vs. available wind generation.

generation. Since negative LMPs are not able to cover the operation costs of generators, power companies are continually making decisions to ramp down their power generations instead of selling excess energy at prices that are not profitable. In this situation, wind power companies would prefer to curtail wind generation. Based on the wind generation operation policies of NYISO and PJM [12]–[14], in the real-time market, once the LMP is below the value that a wind farm could accept (usually a negative bidding price), the wind farm would be directed by the real time control system to cut down the wind generation output. The wind curtailment will obviously impede the effective utilization of available wind generation [15]–[17]. In order to reduce transmission network congestions and make LMPs non-negative, [17] proposed a solution from the economic point of view, by allowing wind generations to provide positive bids similar as those traditional thermal units. For instance, Competitive Renewable Energy Zones (CREZ) program is being deployed in ERCOT in order to increase the utilization of renewable energy (primarily wind) by building more transmission lines and substations. Once CREZ projects are complete, negative price frequency in ERCOT's west zone is expected to be reduced as wind power is transmitted to other demand center [18].

This paper proposes a method to shift the proper amount of load from peak hours to off peaks for enhancing the effective utilization of wind generation, alleviating possible congestions, and making LMPs non-negative. In this paper, load shifting refers to that part of loads can be shifted from peak hours to off peaks under the ISO's direct load control, while the total load throughout the entire schedule horizon is fixed. Load shifting consumers will enroll into the incentive based demand response (DR) programs for declaring their load shifting capabilities and receiving financial incentives for providing such flexibilities [19], [20]. For instance, certain industry loads could shift their production activities from daytime when electricity prices are high to evening with lower electricity prices. The problem is formulated as a mixed-integer linear programming (MILP) model to study the impact of demand response and high penetration wind generation on LMPs. The proposed model incorporates the explicit LMP formulations into the network-constrained unit commitment (NCUC) problem, which are derived from the Karush-Kuhn-Tucker (KKT) optimality conditions of the economic dispatch problem. The proposed study, as compared to literatures, mainly contributes to enhancing the effective utilization of available wind generations by optimally adopting load shifting and alleviating possible network congestions. Meanwhile, the impacts of complex spatial and temporal constraints, including start-up and shut down of generators, ramping constraints, transmission congestions, and load shifting capabilities, will be explored. In electricity markets, LMPs derived from real-time commitment (RTC) and real-time dispatch (RTD) may need comprehensive adjustments in the settlement process. For instance, the NYISO incorporates both the lost opportunity cost of the marginal suppliers and the availability bids [21], which means the final market clearing prices may not exactly be the numbers obtained from RTC/RTD model. Thus, the proposed model may also be helpful for ISOs in their settlement process.

The impacts of uncertain wind power and demand response on power systems operation and power market clearing have been studied in [22]–[24]. This paper focuses on the impacts of wind generation and demand response on the day-ahead market clearing. As the state-of-the-art market clearing mechanism uses deterministic UC/ED models, the deterministic NCUC model is adopted in this paper to keep consistent with the current power market practice. The proposed idea of shifting the proper amount of DR load for alleviating transmission congestions, enhancing the utilization of wind generation, and making LMPs non-negative could be extended to stochastic UC formulations for further exploring the impacts of various uncertainties. One research question on applying the stochastic UC is how to determine the unique set of LMPs for clearing the market, as scenarios in stochastic UC will derive different LMPs. This and other issues on the extension to stochastic UC will be studied in the future work.

The paper is organized as follows. Section II presents the NCUC model, which incorporates the load shifting formulations and LMPs computations. Section III discusses several improved strategies to enhance the computational performance. Section IV illustrates the effectiveness of the proposed methodology with two test systems, and the conclusion is drawn in Section V.

II. Model Description

The objective is to determine the proper load shifting decision for enhancing wind energy utilization, alleviating transmission congestions, and making LMPs non-negative. LMPs provide price signals to market participants for delivering energy at certain locations across the transmission network. LMPs are calculated by the optimal dual solutions of the ED problem [7], [8]. In this paper, the explicit LMP formulations are derived by equivalently converting the ED problem into a set of constraints based on the KKT optimality conditions [25], which are incorporated into the NCUC problem to form a single-level MILP problem.

The objective function (1) is to minimize the total operation cost plus the penalty cost of load shifting. The parameter tuning on the load shifting penalty price ω is necessary for determining the proper amount of load shifting to make LMPs non-negative. If it is too small, more than necessary loads may be shifted for the economic purpose, even if only a smaller portion would be enough to derive non-negative LMPs. On the other hand, a larger penalty factor may locate an uneconomical unit commitment schedule, instead of load shifting, to drive non-negative LMPs. In this paper, the penalty factor is set to be higher than bidding prices of most thermal units.

$$Min \left\{ \sum_{t=1}^{NT} \sum_{i=1}^{NG} \left[\sum_{k=1}^{K} c_i^k \cdot P_{i,t}^k + NL_i \cdot I_{i,t} + SU_{i,t} + SD_{i,t} \right] + \omega \cdot \Delta D_{\text{sum}} \right\} \quad (1)$$

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Constraints (2)–(25) describe the system and unit constraints for the NCUC model. (2)–(7) are minimum ON/OFF time constraints of individual generating units. (8)–(10) are minimum and maximum capacity limitations. (11)–(12) are ramping up and ramping down constraints. (13)–(14) are shift factor based dc transmission network constraints. (15) is the system load balance constraint, and (16)–(17) are system spinning and operating reserve requirements. (18)–(20) describe the spinning and operating reserve capabilities of individual units. (21) describes the relationship between a generator's dispatch and its segment variables. (22)–(25) calculate the startup and the shutdown costs of individual units, in which (22)–(23) represent the relationship among startup/shutdown indicators and unit commitment statuses and (24)–(25) calculate the variable startup and shutdown costs. Time varying startup/shutdown costs can also be incorporated in the proposed model, which has been studied in authors' previous work [29].

$$\sum_{t=1}^{UT_i}(1-I_{i,t})=0 \quad \text{where } UT_i=\max\{0,\min[NT,(T_i^{\text{on}}-X_{i0}^{\text{on}})\cdot I_{i,0}]\} \tag{2}$$

$$\sum_{\tau=t}^{t+T_i^{\text{on}}-1} I_{i,\tau} \ge T_i^{\text{on}}\cdot\left(I_{i,t}-I_{i,(t-1)}\right) \quad \forall t=UT_i+1,\ldots,NT-T_i^{\text{on}}+1 \tag{3}$$

$$\sum_{\tau=t}^{NT}\left[I_{i,\tau}-\left(I_{i,t}-I_{i,(t-1)}\right)\right]\ge 0 \quad \forall t=NT-T_i^{\text{on}}+2,\ldots,NT \tag{4}$$

$$\sum_{t=1}^{DT_i} I_{i,t}=0 \quad \text{where } DT_i=\max\left\{0,\min\left[NT,\left(T_i^{\text{off}}-X_{i0}^{\text{off}}\right)\cdot(1-I_{i0})\right]\right\} \tag{5}$$

$$\sum_{\tau=t}^{t+T_i^{\text{off}}-1}(1-I_{i,\tau})\ge T_i^{\text{off}}\cdot\left(I_{i,(t-1)}-I_{i,t}\right) \quad \forall t=DT_i+1,\ldots,NT-T_i^{\text{off}}+1 \tag{6}$$

$$\sum_{\tau=t}^{NT}\left[1-I_{i,\tau}-\left(I_{i,(t-1)}-I_{i,t}\right)\right]\ge 0 \quad \forall t=NT-T_i^{\text{off}}+2,\ldots,NT \tag{7}$$

$$-P_{i,t}\ge -P_{\max,i}\cdot I_{i,t} \tag{8}$$

$$P_{i,t}\ge P_{\min,i}\cdot I_{i,t} \tag{9}$$

$$-P_{w,t}\ge -P_{\text{forecast},w,t} \tag{10}$$

$$-(P_{i,t}-P_{i,(t-1)}) \ge \begin{bmatrix} -RU_i\cdot I_{i,(t-1)}-P_{\min,i}\left(I_{i,t}-I_{i,(t-1)}\right) \\ -P_{\max,i}(1-I_{i,t}) \end{bmatrix} \tag{11}$$

$$P_{i,t}-P_{i,(t-1)} \ge \begin{bmatrix} RD_i\cdot I_{i,(t-1)}-P_{\min,i}\cdot(I_{i,t}-I_{i,(t-1)}) \\ -P_{\max,i}\cdot(1-I_{i,t}) \end{bmatrix} \tag{12}$$

$$\mathbf{SF}\cdot(\mathbf{Kp}\cdot\mathbf{P_t}-\mathbf{Kd}\cdot\mathbf{D_{d,t}})\le\mathbf{PL_{max}} \tag{13}$$

$$-\mathbf{SF}\cdot(\mathbf{Kp}\cdot\mathbf{P_t}-\mathbf{Kd}\cdot\mathbf{D_{d,t}})\le\mathbf{PL_{max}} \tag{14}$$

$$\sum_{d=1}^{ND}D_{d,t}=\sum_{i=1}^{NG}P_{i,t}+\sum_{w=1}^{NW}P_{w,t} \quad \forall t=1,\ldots,NT \tag{15}$$

$$\sum_i \mathrm{SR}_{i,t}\ge Rs_t \tag{16}$$

$$\sum_i OR_{i,t}\ge Ro_t \tag{17}$$

$$\mathrm{SR}_{i,t}\le I_{i,t}\cdot(10\cdot\mathrm{MSR}_i) \tag{18}$$

$$\mathrm{OR}_{i,t}=\mathrm{SR}_{i,t}+(1-I_{i,t})\cdot\mathrm{QSC}_i \tag{19}$$

$$P_{i,t}+\mathrm{SR}_{i,t}\le P_{\max,i} \tag{20}$$

$$P_{i,t}=P_{\min,i}\cdot I_{i,t}+\sum_{k=1}^{K}P_{i,t}^k \quad 0\le P_{i,t}^k\le \mathrm{Step}_i \tag{21}$$

$$y_{i,t}-z_{i,t}=I_{i,t}-I_{i,(t-1)} \tag{22}$$

$$y_{i,t}+z_{i,t}\le 1 \tag{23}$$

$$\mathrm{SU}_{i,t}=su_i\cdot y_{i,t} \tag{24}$$

$$\mathrm{SD}_{i,t}=sd_i\cdot z_{i,t} \tag{25}$$

In this paper, load shifting refers to that part of loads can be shifted from peak hours to off-peaks under the ISO's direct load control, while the total load throughout the entire schedule horizon is fixed. Constraints (26)–(29) describe the load shifting characteristics, in which (26) calculates the total load shifting, (27) calculates hourly load shifting of load d, and (28) ensures that the total load is fixed. Since the objective minimizes the penalty cost of load shifting, up- and down-shift will not occur simultaneously. That is, at most one of $\underline{\Delta D_{d,t}}$ and $\overline{\Delta D_{d,t}}$ will be non-zero in any single hour. The hourly up- and down-shift of each load are restricted by the pre-defined upper limits (29). Other load shifting constraints, such as hourly load pickup/drop rates, minimum up/down time, and maximum shift duration [26], could also be incorporated for quantifying load shifting.

Constraints (30)–(44) represent the LMP calculation. (30)–(32) introduce additional binary variables $Ip_{i,t}^k$ to indicate which segment a generator is operated at. Although segment bidding prices of individual generators are monotonically increasing, additional binary variables are introduced to build the linkage between segment bidding prices of generators and LMPs in (34)–(35). Constraints (33)–(43) are derived by the KKT optimality conditions [27], [28]. $\delta_{\max i,t}, \delta_{\min i,t}, \delta_{\max w,t}, \delta_{RUi,t}, \delta_{RDi,t}, \mu_{l,1,t}, \mu_{l,2,t}, \lambda_t$, and $\delta_{\text{seg}i,t}^k$ are dual variables of (8)–(15) and (32) in the ED problem, which is an LP problem when binary variables $I_{i,t}$ and $Ip_{i,t}^k$ are fixed to 0–1 values based on the optimal solution of the UC problem. The KKT optimality condition (33)–(43) is valid as long as the feasible region of (8)–(15), given the fixed solutions of $I_{i,t}$ that satisfy (2)–(7) and (16)–(25), is nonempty. Constraint (33) represents the LMP calculation. Constraints (34)–(35) describe that LMPs are affected by dual variables associated with power generation limits, ramping up/down constraints, and segment limitations. Constraints (36)–(43) are utilized to determine whether certain constraints are in the binding condition and, thus, impact LMPs. For instance, constraint (36) considers the maximum output limit of wind generations. If $P_{w,t}$ is equal to the available wind generation, $z_{\max w,t}$ will be equal to 1, which would derive a non-zero shadow price $\delta_{\max w,t}$ that may impact LMPs; otherwise, $z_{\max w,t}$ will be zero and so $\delta_{\max w,t}$, which indicates that $P_{w,t}$ is not binding its upper limit and thus will not impact LMPs. Similarly, constraints (37)–(43) examine the bidding status of maximum and minimum generation limits of thermal units, ramping up limit, ramping down limit, dispatch segment

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limit, and transmission capacity limits, respectively. Finally, constraint (44) forces that all LMPs are non-negative.

$$\Delta D_{\text{sum}} = \sum_{t=1}^{NT}\sum_{d=1}^{ND}\underline{\Delta D_{d,t}} = \sum_{t=1}^{NT}\sum_{d=1}^{ND}\overline{\Delta D_{d,t}} \tag{26}$$

$$D_{d,t} = D_{\text{initial},d,t} + \underline{\Delta D_{d,t}} - \overline{\Delta D_{d,t}} \tag{27}$$

$$\sum_{t=1}^{NT} D_{d,t} = \sum_{t=1}^{NT} D_{\text{initial},d,t} \tag{28}$$

$$\overline{\Delta D_{d,t}} \le \overline{\Delta D_{d,\max}} \quad \underline{\Delta D_{d,t}} \le \underline{\Delta D_{d,\max}} \tag{29}$$

$$\begin{aligned} P_{i,t} = \sum_{k=1}^{K} (P_{\min,i} + (k-1)\cdot \text{Step}_i) \\ \cdot Ip_{i,t}^k + \Delta p_{i,t}^k \quad Ip_{i,t}^k \in \{0,1\} \end{aligned} \tag{30}$$

$$\sum_{k=1}^{K} Ip_{i,t}^k = I_{i,t} \tag{31}$$

$$0 \le \Delta p_{i,t}^k \le \text{Step}_i \cdot Ip_{i,t}^k \tag{32}$$

$$\text{LMP}_{n,t} = \lambda_t + \sum_{l\in L} [\text{SF}(l,n)\cdot(\mu_{l,1,t} - \mu_{l,2,t})] \tag{33}$$

$$\begin{aligned} & c_i^1 \cdot Ip_{i,t}^1 + \sum_{k=2}^{K}\left(c_i^k - c_i^{k-1}\right)\cdot Ip_{i,t}^k = \sum_{n\in N}(e_{n,i}\cdot \text{LMP}_{n,t}) \\ & \quad + \left(-\delta_{\max i,t} + \delta_{\min i,t} + \delta_{RUi,t+1} - \delta_{RDi,t+1} \right. \\ & \quad \left. + \sum_{k=1}^{K}\delta_{\text{seg}i,t}^k\right), t = 1 \\ & c_i^1 \cdot Ip_{i,t}^1 + \sum_{k=2}^{K}\left(c_i^k - c_i^{k-1}\right)\cdot Ip_{i,t}^k = \sum_{n\in N}(e_{n,i}\cdot \text{LMP}_{n,t}) \\ & \quad + \left(-\delta_{\max i,t} + \delta_{\min i,t} - \delta_{RUi,t} + \delta_{RUi,(t+1)} + \delta_{RDi,t} \right. \\ & \quad \left. -\delta_{RDi,(t+1)} + \sum_{k=1}^{K}\delta_{\text{seg}i,t}^k\right), \quad \forall t = 2,\ldots,NT-1 \\ & c_i^1 \cdot Ip_{i,t}^1 + \sum_{k=2}^{K}\left(c_i^k - c_i^{k-1}\right)\cdot Ip_{i,t}^k = \sum_{n\in N}(e_{n,i}\cdot \text{LMP}_{n,t}) \\ & \quad + \left(-\delta_{\max i,t} + \delta_{\min i,t} - \delta_{RUi,t} + \delta_{RDi,t} \right. \\ & \quad \left. + \sum_{k=1}^{K}\delta_{\text{seg}i,t}^k\right), t = NT \end{aligned} \tag{34}$$

$$0 = \sum_{n\in N}(e_{n,w}\cdot \text{LMP}_{n,t}) + (-\delta_{\max w,t}), \forall t = 1,\ldots,NT \tag{35}$$

$$\begin{aligned} & -P_{w,t} + P_{\text{forecast},w,t} \ge (1 - z_{\max w,t})\cdot\varepsilon \\ & -P_{w,t} + P_{\text{forecast},w,t} \le (1 - z_{\max w,t})\cdot Q \\ & 0 \le \delta_{\max w,t} \le Q\cdot z_{\max w,t} \quad z_{\max w,t}\in\{0,1\} \end{aligned} \tag{36}$$

$$\begin{aligned} & -P_{i,t} + P_{\max,i}\cdot I_{i,t} \ge (1 - z_{\max i,t})\cdot\varepsilon \\ & -P_{i,t} + P_{\max,i}\cdot I_{i,t} \le (1 - z_{\max i,t})\cdot Q \\ & 0 \le \delta_{\max i,t} \le Q\cdot z_{\max i,t} \quad z_{\max i,t}\in\{0,1\} \end{aligned} \tag{37}$$

$$\begin{aligned} & P_{i,t} - P_{\min,i}\cdot I_{i,t} \ge (1 - z_{\min i,t})\cdot\varepsilon \\ & P_{i,t} - P_{\min,i}\cdot I_{i,t} \le (1 - z_{\min i,t})\cdot Q \\ & 0 \le \delta_{\min i,t} \le Q\cdot z_{\min i,t} \quad z_{\min i,t}\in\{0,1\} \end{aligned} \tag{38}$$

$$\begin{aligned} & -P_{i,t} + P_{i,(t-1)} + RU_i \ge (1 - z_{RUi,t})\cdot\varepsilon \\ & -P_{i,t} + P_{i,(t-1)} + RU_i \le (1 - z_{RUi,t})\cdot Q \\ & 0 \le \delta_{RUi,t} \le Q\cdot z_{RUi,t} \quad z_{RUi,t}\in\{0,1\} \end{aligned} \tag{39}$$

$$\begin{aligned} & P_{i,t} - P_{i,(t-1)} - RD_i \ge (1 - z_{RDi,t})\cdot\varepsilon \\ & P_{i,t} - P_{i,(t-1)} - RD_i \le (1 - z_{RDi,t})\cdot Q \\ & 0 \le \delta_{RDi,t} \le Q\cdot z_{RDi,t} \quad z_{RDi,t}\in\{0,1\} \end{aligned} \tag{40}$$

$$\begin{aligned} & -\Delta p_{i,t}^k \ge -Step_i \\ & -\Delta p_{i,t}^k + \text{Step}_i \ge (1 - z_{\text{seg}i,t}^k)\cdot\varepsilon \\ & -\Delta p_{i,t}^k + \text{Step}_i \le (1 - z_{\text{seg}i,t}^k)\cdot Q \\ & \delta_{\text{seg}i,t}^k \le Q\cdot z_{\text{seg}i,t}^k \quad \delta_{\text{seg}i,t}^k \ge -Q \\ & \quad \cdot z_{\text{seg}i,t}^k \quad z_{\text{seg}i,t}^k \in\{0,1\} \end{aligned} \tag{41}$$

$$\begin{aligned} & -\mathbf{SF}\cdot\mathbf{Kp}\cdot P_{i,t} + \mathbf{SF}\cdot\mathbf{Kd}\cdot D_{d,t} \\ & \quad + PL_l^{\max} \ge (1 - zu_{l,1,t})\cdot\varepsilon \\ & -\mathbf{SF}\cdot\mathbf{Kp}\cdot P_{i,t} + \mathbf{SF}\cdot\mathbf{Kd}\cdot D_{d,t} + PL_l^{\max} \\ & \quad \le (1 - zu_{l,1,t})\cdot Q \mu_{l,1,t} \ge -Q\cdot zu_{l,1,t} \\ & \quad \mu_{l,1,t} \le 0 \quad zu_{l,1,t}\in\{0,1\} \end{aligned} \tag{42}$$

$$\begin{aligned} & \mathbf{SF}\cdot\mathbf{Kp}\cdot P_{i,t} - \mathbf{SF}\cdot\mathbf{Kp}\cdot D_{d,t} \\ & \quad + PL_l^{\max} \ge (1 - zu_{l,2,t})\cdot\varepsilon \\ & \mathbf{SF}\cdot\mathbf{Kp}\cdot P_{i,t} - \mathbf{SF}\cdot\mathbf{Kp}\cdot D_{d,t} \\ & \quad + PL_l^{\max} \le (1 - zu_{l,2,t})\cdot Q \\ & \mu_{l,2,t} \ge -Q\cdot zu_{l,2,t} \quad \mu_{l,2,t} \le 0 \quad zu_{l,2,t}\in\{0,1\} \end{aligned} \tag{43}$$

$$\text{LMP}_{n,t} \ge 0 \tag{44}$$

III. Improved Solution Strategies

The proposed MILP problem (1)-(44) includes $((3K+6)\cdot NG + 3ND + NB + 2NW + 2L + 1)\cdot NT + L + 1$ continuous variables, $((2K+5)\cdot NG + NW + 2L)\cdot NT$ binary variables, $(5NG + ND + NB + NW + 2)\cdot NT + 1$ equality constraints, and $((20+4K)\cdot NG + NB + 4NW + 8L)\cdot NT + 1$ inequality constraints. Thus, the proposed problem for practical power systems would be an intractable task without decomposition. In this paper, several improved solution strategies are discussed to enhance the computational performance and accelerate the convergence.

A. Reduce the Number of Binary Variables

In (26)–(27), binary variable $Ip_{i,t}^k$ determines which segment $P_{i,t}$ is located at. Thus, $Ip_{i,t}^k$ and $I_{i,t}$ would follow an additional constraint (45) that the summation of all $Ip_{i,t}^k$ is equal to $I_{i,t}$. Thus, one of $Ip_{i,t}^k$ can be set as a continuous variable from zero to one. Based on (45), this continuous variable can be only equal to 0 or 1. This formulation is mathematically equivalent to the original model with a reduced number of binary variables.

$$\sum_{k=1}^{K} Ip_{i,t}^k = I_{i,t} \tag{45}$$

B. Tighter Formulation With Additional Constraints

There are two sets of binary indicators for describing the dispatch level of a unit. $Ip_{i,t}^k$ determines which segment $P_{i,t}$ is

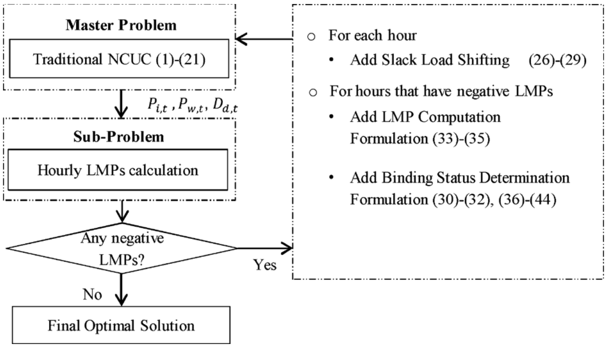

Fig. 2. Flowchart of the proposed decomposition solution strategy.

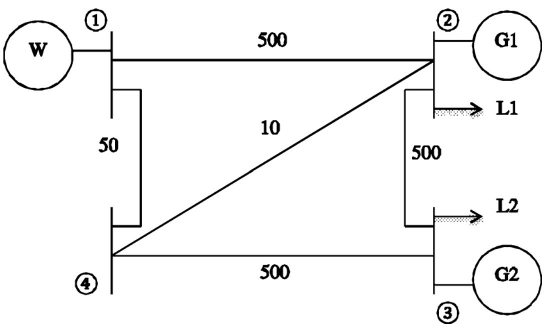

Fig. 3. 4-bus system.

TABLE I
GENERATOR INFORMATION

Unit	Pmin (MW)	Pmax (MW)	No Load Cost (\$)	Startup Cost (\$)	Segment Price (\$/MW)
G1	80	400	30	50	12
G2	30	100	40	60	10

TABLE II
HOURLY WIND AND LOAD INFORMATION (MW)

Hour	L1	L2	Available Wind
1	200	30	80
2	320	100	80

TABLE III
BRANCH INFORMATION

Branch	From	To	X (p.u)	PLMax (MW)
1	1	2	0.1	500
2	1	4	0.1	50
3	2	3	0.1	500
4	2	4	0.1	10
5	3	4	0.1	500

TABLE IV
RESULTS OF CASE 1—GENERATION DISPATCH (MW)

Hour	Wind	G1	G2	L1	L2
1	70	160	0	200	30
2	80	280	60	320	100

TABLE V
RESULTS OF CASE 1—LMP (\$/MWH)

Bus	1	2	3	4
Hour 1	0	12	0	-12
Hour 2	10	12	10	8

located at, and $z_{\mathrm{seg}i,t}^{k}$ describes if the dispatch reaches segment bounds. Thus, constraint (46) can describe the relationship between $Ip_{i,t}^{k}$ and $z_{\mathrm{seg}i,t}^{k}$, which would tighten the formulation and drive the LP solution toward integer solutions faster during the branch-and-cut solving process.

$$z_{\mathrm{seg}i,t}^{k} \leq Ip_{i,t}^{k} \tag{46}$$

C. Decomposition Solution Strategy

The proposed problem may encounter significant computational burdens for practical power systems and cannot be solved in one run, because of a large number of binary variables and constraints introduced in the LMP calculation (30)–(44). Alternatively, the proposed model can be decomposed into one master NCUC problem (1)–(25) and sub-problems for hourly LMP evaluation. Fig. 2 shows iterative procedure between the master problem and sub-problems that solves the proposed model, which are discussed as the following steps:

Step 1: The master NCUC problem (1)–(25) is solved first. That is, load shifting is not considered and the LMP calculation is not included in the first iteration.

Step 2: The optimal dispatches from Step 1 are used to calculate LMPs at each hour in sub-problems.

Step 3: If LMP at any bus in a certain hour is negative, the LMP calculation formulation (33)–(35) and the binding status detection formulation (30)–(32) and (36)–(44) for that certain hour, as well as the slack load shifting constraints (26)–(29) for all hours, are added to Step 1 for further iterations. Otherwise, the optimal solution is obtained.

The proposed decomposition strategy would enhance the computational performance, because a huge number of variables and constraints (26)–(44) are excluded in the first iteration, and they will be included in later iterations only if negative LMPs are observed in certain hours.

IV. NUMERICAL EXAMPLE

A 4-bus system and the modified IEEE 118-bus system [29] are utilized to illustrate the effectiveness of the proposed model.

A. 4-Bus System

The 4-bus system is studied for a period of two hours, which includes 2 thermal units, 1 wind farm, 2 loads, and 5 branches as shown in Fig. 3. The generator data, the load information, and the transmission network data are given in Tables I–III, respectively. The hourly available wind generation is 19.04% of the system peak load. In this case, hour 1 is an off peak period and hour 2 represents an on-peak hour. The system reserve requirement and other generator constraints, such as minimum ON/OFF time and ramping constraints, are relaxed for the sake of discussion. The following three cases are studied:

Case 1: The traditional NCUC without load shifting.
Case 2: The proposed model with the optimal load shifting to make LMPs non-negative.
Case 3: The sensitivity analysis on the penalty cost of load shifting.

Case 1: The Traditional NCUC Without Load Shifting: The optimal results of Case 1 are shown in Table IV with the total operation cost of \$6090. It shows that only wind and G1 are used to supply loads in the off-peak hour, and G2 has to be turned on to supply the peak load in hour 2. LMPs and power flows are shown in Tables V and VI, respectively.

TABLE VI
RESULTS OF CASE 1—POWER FLOW (MW)

Branch	From	To	Hour 1	Hour 2
1	1	2	40	45
2	1	4	30	35
3	2	3	10	15
4	2	4	-10	-10
5	3	4	-20	-25

In the first hour, branch 4 is congested in the negative direction. The net power injections of the four buses are P_w, P_1-200, P_2-30, and 0, respectively. Thus, with the shift factor matrix shown in (43), power flow of branch 4 is calculated as $0\cdot P_w + 0.25\cdot(P_1-200)+0\cdot(P_2-30)+(-0.25)\cdot 0 = 0.25\cdot(P_1-200)$, which has to be within the range of -10 MW and 10 MW. That is, $-10\le 0.25\cdot(P_1-200)\le 10$, which turns out to be $160\le P_1\le 240$. Thus, even the bidding price of wind is cheaper than G1, due to the congestion of branch 4 in the negative direction, G1 has to be dispatched no less than 160 MW, and wind is dispatched $(200+30)-160=70$ MW at most. Thus, the congestion of branch 4 in the negative direction causes the non-fully utilization of wind in the first hour. The negative LMP at bus 4 is caused by the congestion of branch 4 together with dispatch levels of generating units. Since wind energy is not fully utilized, both G1 and wind generator are marginal units at hour 1. The dual variable λ_1 associated with the power balance equation (15) is set as zero, the bidding price of wind generator which is cheaper than that of G1. Thus, LMP at the reference bus 1 is 0 \$/MWh. In addition, since branch 4 is congested in the negative direction, the dual variable $\mu_{4,2,1}$ associated with the capacity limit of branch 4 is -48, and all other dual variables associated with (13)–(14) are zeros. Therefore, LMP at bus 4 is calculated as $0+(-0.375)\cdot 0+(-0.625)\cdot 0+(-0.125)\cdot 0+(-0.25)\cdot[0-(-48)]+(-0.125)\cdot 0=-12$ \$/MWh according to (29).

$$\mathrm{SF}=\begin{bmatrix}0 & -0.625 & -0.5 & -0.375\\ 0 & -0.375 & -0.5 & -0.625\\ 0 & 0.125 & -0.5 & -0.125\\ 0 & 0.25 & 0 & -0.25\\ 0 & 0.125 & 0.5 & -0.125\end{bmatrix} \tag{47}$$

In hour 2, although branch 4 is also congested, the LMP at bus 4 is positive. The reason is that the available wind generation is fully utilized and wind cannot be a marginal unit to set the price. G1 and G2 are the marginal units in hour 2, as compared to the marginal unit set of wind and G1 in hour 1.

Case 2: The Proposed Model: Load shifting is considered in this case for fully utilizing all available wind generation, alleviating network congestions, and making LMPs non-negative. The penalty factor is set as 20 \$/MWh, which is higher than bid prices of G1 and G2. Thus, it can assure that the system will not uneconomically turn on expensive G2 in hour 1 for making LMPs positive. In this case, L1 represents a fixed load that is not allowed to be shifted. The limitations on upward and downward load shifting of L2 are set as 50% of the peak load of L2, i.e., 50 MW.

The objective of Case 2 is \$6290, which includes the operation cost of \$6090 and the load shifting penalty cost of \$200. The generation dispatch, LMPs, and power flows are shown in Tables VII–IX. Table VII shows that L2 shifts 10 MW from hour 2 to hour 1. With the load level of 200 MW for L1 and 40 MW for L2 at hour 1, all available wind generation are fully utilized.

TABLE VII
RESULTS OF CASE 2—DISPATCH (MW)

Hour	Wind	G1	G2	L1	L2
1	80	160	0	200	40
2	80	280	50	320	90

TABLE VIII
RESULTS OF CASE 2—LMPS (\$/MWH)

Bus	1	2	3	4
Hour 1	12	12	12	12
Hour 2	10	12	10	8

TABLE IX
RESULTS OF CASE 2—POWER FLOW (MW)

Branch	From	To	Hour 1	Hour 2
1	1	2	40	45
2	1	4	30	35
3	2	3	10	15
4	2	4	-10	-10
5	3	4	-20	-25

TABLE X
RESULTS OF CASE 3—SENSITIVITY ANALYSIS ON PENALTY COST

Penalty Cost (\$/MWh)	Total Cost (\$)	Amount of Shifting Load (MWh)
0	6090	10 - 50
10	6190	10
20	6290	10
85	6830	0

Although branch 4 is still congested, the dual variable related to the branch capacity constraint is 0. In addition, G1 becomes the only marginal unit and LMPs are all 12\$/MWh in hour 1. Besides, G2 is still off at hour 1, which indicates that the system does not uneconomically turn on expensive generators to make LMPs positive.

Case 3: Sensitive Analysis on the Penalty Cost of Load Shifting: The setting on the penalty cost of load shifting is associated with the bidding price of generating units, which will impact load shifting results. Table X compares the total cost and the load shifting quantity with four penalty cost values. When the penalty cost is zero, load shifting is preferred and a total of up to 50 MW is shifted from hour 2 to hour 1 for achieving the minimum total cost of \$60 900. In fact, there are multiple optimal solutions exist with the penalty cost of zero. All load shifting values between 10 MW and 50 MW would derive the same optimal total cost of \$6090. As the penalty cost increases, only a proper portion of load is shifted to make LMPs non-negative. It can be seen that only 10 MWh load is shifted, and the total costs are increased to \$6190 and \$6290 with the penalty cost of \$10/MWh and \$20/MWh, respectively. When the penalty cost is significantly higher than the average cost of generating units, no load will be shifted and additional expensive generators will be committed to make LMPs non-negative. For instance, if penalty cost is set to \$85/MWh, the system will not shift any loads but commit additional expensive units, and the total cost is increased to \$6830. The penalty cost represents the incentives paid to DR loads for their participation into direct load control based DR programs. Thus, lower penalty costs such as 0\$/MWh will discourage DR loads to participate into the direct load control based DR program. On the other hand, higher penalty costs will lead ISOs to call for alternative expensive generators instead of DR loads. Thus,

TABLE XI
RESULTS OF CASE 1—DUAL VARIABLES CORRESPONDING TO THE NETWORK CONGESTIONS

Hour	Branch (congested in positive direction)	Dual Variable	Branch (congested in negative direction)	Dual Variable
1	-	-	152	-25.84
2	-	-	129	-4.39
			152	-23.88
3	-	-	129	-28.25
4	-	-	129	-8.31
5	-	-	129	-8.09
6	-	-	129	-7.75
7	-	-	129	-11.36
8	-	-	129	-7.37
10	-	-	155	-22.09
11	-	-	155	-23.26
12	-	-	155	-21.51
13	-	-	155	-22.47
14	-	-	155	-41.06
17	-	-	129	-31.25
			155	-14.19
18	-	-	129	-26.23
			152	-19.34
19	-	-	129	-11.61
			152	-8.25
20	-	-	129	-12.37
			152	-4.54
21	-	-	129	-10.38
			152	-10.87
22	-	-	129	-10.58
			152	-8.46
23	158	-11.29	129	-10.58
			152	-21.31
24	135	-12.87	152	-24.56

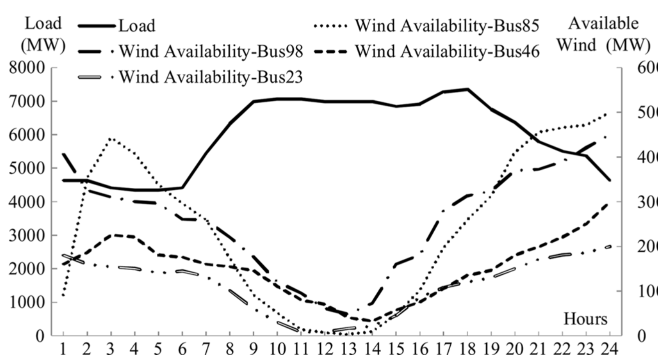

Fig. 4. Available wind generation and system load profiles.

a proper penalty cost is important for the effective deployment of direct load control based DR program.

B. Modified IEEE 118-Bus System

The modified IEEE 118-bus system with 54 thermal generators, 4 wind farms, and 186 branches is used in a 24-hour study, for illustrating the effectiveness of the proposed model for practical power systems. The original IEEE 118-bus system data can be found in [29] which comprises of three zones. The four wind farms are added at bus 23, 46, 85, and 98 which ensure that each zone at least has one wind farm. The available wind energy profile [10] and the initial load information are shown in Fig. 4. The bidding price for wind generation is 0 \$/MWh. The first two cases studied in the 4-bus system are explored for the 118-bus system.

Case 1: The Traditional NCUC Without Load Shifting: The operation cost of Case 1 is \$1 915 535.95. Without load shifting, in most off-peak periods, available wind generations located

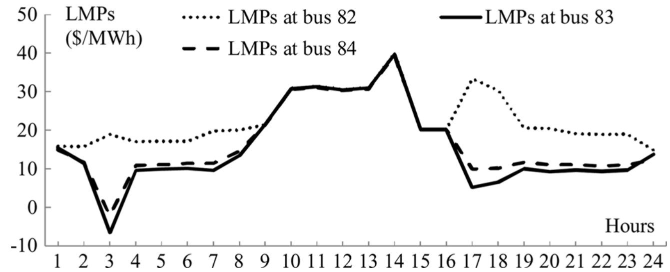

Fig. 5. LMPs without the load shifting.

at bus 85 and bus 98 are not fully utilized due to congestions on branches 129, 152, and 155. Table X lists all congestion details and the corresponding dual variable solutions. It can be observed that the smallest dual variable occurs in hour 3, which derives a negative LMP of -6.55 \$/MWh at bus 83 and -2.14 \$/MWh at bus 84, as shown in Fig. 5. In addition, Fig. 5 shows that more LMP fluctuations are observed at buses 83 and 84 than bus 82. The shift factors of buses 83 and 84 with respect to branch 129 are -0.8162 and -0.6600, are -0.0852 and -0.1069 with respect to branch 152, and are 0.0845 and 0.0756 with respect to branch 155. In comparison, the shift factors of bus 82 are only 0.0830, -0.0712, and 0.0903 with respect to those three branches. Thus, the congestions on branch 129 will impact LMPs on buses 83 and 84 more significantly than that of bus 82, because the magnitudes of shift factors for buses 83 and 84 are much bigger.

Case 2: The Proposed Model: In this case, the penalty factor is set 20 \$/MW, which is higher than bid prices of most generators. The limits on both upward and downward load shifting of each DR load are set as 50% of the corresponding peak load. Table XII shows the load shifting results. A total of 398.1 MWh load is shifted for making LMPs non-negative. It shows that significant changes occur on loads located at buses 82, 83, 86, 94, and 98, which are geographically close to bus 83 with negative LMPs in Case 1. The loads located at buses 83 and 86 are increased at hours 3, which affect power flows of branches that connect buses 83 and 84. Bus 83 has a larger shift factor of -0.8162 on branch 129, which will have a bigger impact on LMP at bus 83. After load shifting, the dual variable related to the capacity limit of branch 152 at hour 3 is decreased to -23.98 (i.e., $\mu_{152,1,3} - \mu_{152,2,3}$), as compared to -23.88 in Case 1. In addition, branch 129 is no longer congested. Therefore, LMP of bus 83 at hour 2 becomes a positive number.

Fig. 6 shows the changes in LMPs. When the proper amount of loads is shifted from hours 10, 11, 12, 13, and 14 to hours 1, 2, 3, 4, 17, 18, 20, 22, 23, and 24, LMPs at hour 3 are all non-negative. In addition, LMPs at other hours also change slightly because loads are shifted upward and downward among hours for guaranteeing the fixed total load. As the load profiles are different before and after the load shifting, particularly in the first two hours, the optimal unit commitment and generation dispatches are changed. These changes affect the generation dispatch at hours 8 and 9 due to minimum ON/OFF and ramping up/down constraints of generators, which also impact the LMPs, even though loads in those two hours are not changed. The total consumer payment is calculated by the summation of product of load consumptions and corresponding LMPs at each bus in each hour. The total load payment is decreased from \$3 207 520.17 in Case 1 to \$3 125 510.29 in Case 2. The social welfare (i.e., which can be calculated by using consumer payment minus operation cost and penalty cost) is decreased from \$1 291 984.22 (\$3 207 520.17–1 915 535.95)

TABLE XII
LOAD—AFTER LOAD SHIFTING (MW)

Hour	Bus	Original Loads	Loads After Shifting	Quantity Shifted
1	82	67.19	96.90	-29.71
	94	37.07	64.10	-27.03
	98	42.17	72.91	-30.74
2	94	37.07	64.10	-27.03
	98	42.17	54.43	-12.26
3	83	23.84	42.07	-18.23
	84	12.80	14.12	-1.32
	86	24.72	28.05	-3.33
4	83	23.44	41.68	-18.24
	86	24.31	37.08	-12.77
	94	34.72	35.57	-0.85
10	83	38.14	19.89	18.25
	94	56.50	31.28	25.22
	98	64.26	57.19	7.07
11	83	38.14	19.89	18.25
	84	20.48	19.15	1.33
	94	56.50	29.47	27.03
	98	64.26	36.11	28.15
12	83	37.74	19.49	18.25
	94	55.91	41.27	14.64
	98	63.59	59.17	4.42
13	83	37.74	19.49	18.25
	84	20.26	10.47	9.79
	94	55.91	34.42	21.49
	98	63.59	32.85	30.74
14	83	37.74	19.49	18.25
	84	20.26	10.47	9.79
	86	39.13	20.79	18.34
	94	55.91	29.76	26.15
	98	63.59	32.85	30.74
17	82	105.60	64.59	41.01
	83	39.32	57.57	-18.25
	84	21.12	30.91	-9.79
	98	66.27	55.23	11.04
18	83	39.73	57.97	-18.24
	84	21.33	31.12	-9.79
	98	66.94	67.14	-0.20
20	83	34.35	52.60	-18.25
22	94	44.04	71.06	-27.02
	98	50.10	60.33	-10.23
23	94	42.96	71.07	-27.01
	98	48.87	76.87	-28.00
24	82	67.20	78.50	-11.30
	86	25.95	28.17	-2.22
	94	37.07	42.61	-5.54
	98	42.17	72.92	-30.75

in Case 1 to $1 210 073.94 (3 125 510.29–1 907 474.35-7962) in Case 2 However, this conclusion may not be generalized. In this paper, the objective is to minimize the total operation cost instead of minimizing the total consumer payment or maximizing the social welfare. Thus, after shifting, the operating cost will decrease since the utilization of wind generators is increased and cheaper generators are dispatched more to supply the load. However, the total consumer payment may increase or decrease after load shifting, depending on the LMPs after DR load shifting, which is also the case for the social welfare. The penalty cost of load shifting is included in the objective for assuring that only a minimum quantity of load shifting will be applied to make LMPs positive. In addition, load shifting consumers will receive financial incentives for enrolling into the incentive based DR and providing such flexibilities, which would help compensate the potential payment increases and enhance their financial situation.

In this case, the load shifting penalty cost is $7962 and the operation cost is $1 907 474.35. There are two main reasons that the operation cost is smaller than that of Case 1. The first is that as a certain amount of loads is shifted from peak hours to off peaks, cheaper generators are dispatched more to supply the load during off peak hours and, thus, reduce the operation cost. For instance, as compared to Case 1, generators 3, 4, 29, 30, 39, 40, and 52, which are located at buses 8, 10, 69, 70, 87, 89, and 112, are dispatched 60 MW, 35.92 MW, 30.65 MW, 27.91 MW, 145.38 MW, 50.61 MW, and 87.33 MW more than those of Case 1. Second, the load shifting would also enhance the utilization of available wind energy and, thus, further reduce the operation cost. As shown in Table XIII, more wind energy is utilized at hours 1, 2, 3, 21, 23, and 24 when loads are shifted to these five hours. At hour 3, because the load on bus 83 is increased and branch 130 connecting buses 83 and 84 is not congested, wind unit is dispatched more to supply the load on bus 83 at hour 3. In addition, the wind energy utilizations in other hours are no changed significantly as compared to Case 1, even the system load levels are decreased in those hours.

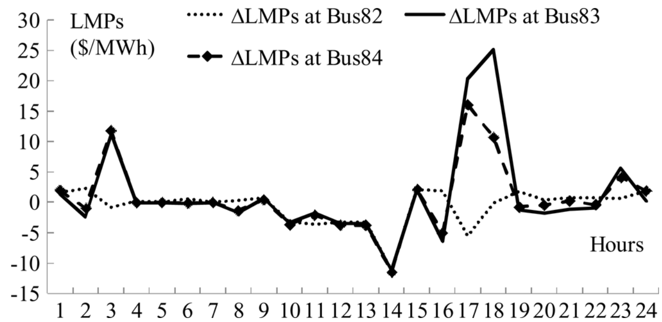

Fig. 6. Changes in LMPs as compared to Case 1.

TABLE XIII
CHANGES OF WIND GENERATION OUTPUT (MW)

Hour	Before Load Shifting		After Load Shifting	
	Wind-Bus85	Wind-Bus98	Wind-Bus85	Wind-Bus98
1	91.19	402.37	91.19	400.91
2	353.47	337.69	353.47	355.15
3	416.32	310.35	443.51	310.35
21	432.45	372.67	455.54	372.67
23	471.64	410.69	471.64	420.78
24	500	402.37	500	422.92

In order to illustrate the effectiveness of the proposed model on enhancing the wind energy utilization, it is compared with a simplified model, which is formulated as the NCUC model plus load shifting constraints while neglecting constraints related to the LMP formulation. That is, the simplified model only includes (1)–(29) and (36)–(43), while eliminating binary indicator variables in (36)–(43) which are used for the LMP calculation. For instance, (36) can be represented as $-P_{w,t} + P_{\mathrm{forecast},w,t} \geq 0$ by eliminating the binary indicator $z_{\max,w,t}$. Using the same input data as Case 2, a total of 374.48 MWh load is shifted from peak periods to off-peaks, and the operation cost is $1 906 852.69, which is slightly smaller than $1 907 474.35 of Case 2. Table XIV compares the total load shifting and the total wind energy utilization of the three cases. Case 1 does not adopt load shifting and the total wind energy utilization is 17 778.55 MWh. As the simplified model is to economically utilize load shifting for minimizing the total cost while not restricting LMPs non-negative, it shifts 23.62 MWh less load (i.e., 398.1 MWh–374.48 MWh), and utilization of wind energy is same as the proposed model in Case 2. A sensitivity index, which measures the change in the wind energy utilization with respect to the change in the load shifting quantity, is adopted to illustrate the effectiveness of the proposed model for optimally adopting load shifting to enhance the wind energy utilization.

TABLE XIV
THE COMPARISON OF CASES 1–2 AND A SIMPLIFIED MODEL WITH NCUC PLUS LOAD SHIFTING

	NCUC	NCUC Plus Load Shifting	The Proposed Model
Total Load Shifting (MWh)	0	374.48	398.1
Total Wind Utilization (MWh)	17778.55	17875.47	17875.47
Sensitivity Index	-	25.88%	24.34%

The values of the sensitivity index for the simplified model and the proposed model are $(17\,875.47-17\,778.55)/(374.48-0) = 25.88\%$ and $(17\,875.47-17\,778.55)/(398.10-0) = 24.34\%$, respectively. It can be seen that the sensitivity index value of the proposed model is slightly lower than that of the simplified model. However, LMPs can be restricted to non-negative values by using the proposed model while not decreasing the wind utilization. Thus, the proposed model by restricting LMPs non-negative will help alleviate possible congestions and enhance the wind energy utilization as compared to the traditional NCUC model.

All case studies utilize CPLEX 12.1.0 on an Intel Core-i7 3.5-GHz personal computer with 8 GB RAM. This 24-hour NCUC problem in Case 2 is solved by the proposed decomposition solution strategy in 1795 seconds, with a duality gap target of 0.1%. In comparison, the problem cannot be solved directly by the current version of CPLEX without the proposed strategy. After running for more than 10 hours, the CPLEX could not locate a feasible solution to the problem at any MILP gap level.

V. CONCLUSION

This paper analyzes the impact of demand response and wind generation on LMPs, by including the explicit formulations of LMPs into the traditional NCUC problem, which are derived by the KKT conditions. The proposed model is to determine the proper amount of load shifting that would fully utilize available wind generation, alleviate transmission congestions, and make LMPs non-negative. Decomposition solution strategies are discussed to improve the computational performance and accelerate the convergence. Numerical case studies illustrate that demand response will alleviate possible congestions and enhance the utilization of wind generations by shifting proper amount of loads from peak hours to off peaks.

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