MITSUBISHI ELECTRIC RESEARCH LABORATORIES
http://www.merl.com

Mitigating Substation Demand Fluctuations Using Decoupled Price Schemes for Demand Response

Sun, H.; Minot, A.; Nikovski, D.N.; Hashimoto, H.; Takano, T.; Takaguchi, Y.

TR2016-118 September 2016

Abstract

In this paper, we propose a decoupled substation price model with separate charges for base energy production, up/down reserve usages and reserve usage variations. Using the decoupled price scheme, the flexible loads in the distribution system are scheduled to closely follow variations in renewable generation in order to mitigate demand fluctuations in substation. This reduces the need for reserve unit power production, thereby allowing transmission systems to operate at lower cost and higher efficiency. We formulate an optimization problem to determine the optimal scheduling of flexible loads subject to power balance, power flow and demand response constraints. The optimization problem is solvable by computationally efficient linear programming methods. Realtime and day-ahead models are considered. Numerical examples on a modified 13-node test feeder demonstrate the effectiveness of the proposed method.

IEEE ISGT

Mitigating Substation Demand Fluctuations Using Decoupled Price Schemes for Demand Response

Hongbo Sun[1], Ariana Minot[2], Daniel Nikovski[1], Hiroyuki Hashimoto[3], Tomihiro Takano[3], and Yusuke Takaguchi[3]

[1]Mitsubishi Electric Research Laboratories
Cambridge, MA 02139, USA

[2]School of Engineering and
Applied Sciences, Harvard University
Cambridge, MA 02138, USA

[3]Advanced Technology R&D Center
Mitsubishi Electric Corporation
Hyogo 661-8661, Japan

***Abstract*—In this paper, we propose a decoupled substation price model with separate charges for base energy production, up/down reserve usages and reserve usage variations. Using the decoupled price scheme, the flexible loads in the distribution system are scheduled to closely follow variations in renewable generation in order to mitigate demand fluctuations in substation. This reduces the need for reserve unit power production, thereby allowing transmission systems to operate at lower cost and higher efficiency. We formulate an optimization problem to determine the optimal scheduling of flexible loads subject to power balance, power flow and demand response constraints. The optimization problem is solvable by computationally efficient linear programming methods. Real-time and day-ahead models are considered. Numerical examples on a modified 13-node test feeder demonstrate the effectiveness of the proposed method.**

***Index Terms*—Distribution systems, flexible loads, generation following, renewable generation, power markets.**

I. INTRODUCTION

Independent system operators are responsible for maintaining an instantaneous and continuous balance between supply and demand of power at transmission substations. This task is complicated by the increased presence of distributed energy resources (DERs), such as wind and solar generation, in the distribution system that connected with transmission substation. The unpredictable nature of these renewable energy sources leads to greater fluctuations in the amount of generated power available. Such fluctuations in generation capacity are present in addition to fluctuations in power demand. Traditionally, to achieve a power balance in the presence of heightened volatility, operators must increase the use of reserve capacities which are able to operate in load following mode [1]. However, increasing power production by reserve units comes at the cost of reducing power production by more energy-efficient base-load generation units, reducing the environmental benefits of using renewable DERs.

Rather than rely on reserve units to act in load-following mode, there has been much interest on the topic of demand response, which adjusts loads in order to smooth out volatility in renewable generation capacity and power demand [2]–[4]. A variety of work has studied how to incorporate demand side reserves into the real-time and day-ahead energy markets [5], [6]. In [7], a security-constrained algorithm for forward market clearing is proposed that takes into account demand side flexibility, and in [8], the authors develop a mechanism for jointly clearing rather than sequentially clearing the energy and reserve markets. A two-stage stochastic program is presented in [9] for jointly optimizing the clearing of the energy and reserve markets under different wind production scenarios. In relation to our work which further explores the use of decoupled price mechanisms, separate pool energy prices and balancing energy prices are designed in [9].

In this work, we consider how to develop an appropriate market mechanism that smoothens fluctuations in substation demand by encouraging a scheduling of flexible loads that closely follows variations in renewable generation. Under such a scheme, the transmission system is able to better utilize base-load generation units and operate at increased efficiency. In particular, we propose a decoupled substation price model with separate components for base energy production, up/down reserve usage, and reserve usage variation. Unlike standard pricing models which consider a single cost component, the upshot of using a decoupled pricing scheme is that in some cases it is favorable to increase demand in order to lower power costs at the substation. For example, when power demand is below the normal operating range, it may be financially advantageous to increase power demand instead of using reserve units for achieving power balance. Another result of using the decoupled scheme is that it provides incentives to reduce load variation between consecutive intervals. For example, in some instances, it may be more economical for the distribution system to keep load stable when the power demand is beyond the normal range. An optimization formulation is proposed for scheduling flexible loads under decoupled price scheme. The objective of optimization problem is to minimize the summation of substation power purchase cost, available but unused renewable penalty cost and demand response cost subject to power balance, power flow and demand response constraints. Both real-time and day-head markets are considered. The optimization problem formulation is solvable by computationally efficient linear programming methods. Through optimal scheduling of loads with flexibility, the renewable has been fully utilized, and the need for use of reserve units is also reduced. Numerical experiments on a modified 13-node test feeder system demonstrate the effectiveness of the proposed method.

II. PROBLEM STATEMENT

A. Distribution System Modelling and Decoupled Price Scheme

The proposed method is targeted for distribution systems with a significant penetration of renewable generation. A typical distribution system is radially configured, and its loads, branches, and generations may be three-phase unbalanced. Therefore, each phase needs to be modeled separately during its operation and control. The renewable generations and loads may be connected to a bus through either a DELTA-connection or a WYE-connection. Each load may contain constant-power components, constant-current components, and constant-impedance components. In this paper, all components are treated as constant powers, and only active powers are considered. The DELTA-connected generations, or loads are converted to equivalent WYE-connected ones. For example, the active power of a generation/load between phase *x* and phase *y*, $P(xy)$ can be converted into active powers of two equivalent generations/loads at phase *x* and phase *y*, $P^x(xy)$ and $P^y(xy)$ according to:

$$P^x(xy) = \beta^+ P(xy)\,,\ P^y(xy) = \beta^- P(xy)\,, \qquad (1)$$

where β^+ and β^- are conversion factors defined based on the generation/load's power factor, $\cos\phi$ and the voltage relationship between balanced three phases. The conversion factors are given as follows:

$$\beta^+ = \frac{1}{2} + \frac{\sqrt{3}}{6}\tan\phi\,,\ \beta^- = \frac{1}{2} - \frac{\sqrt{3}}{6}\tan\phi\,. \qquad (2)$$

The active power of equivalent generation/load for any phase *x* that is connected with both WYE-connected and DELTA-connected generations/loads, $P_{EQ}(x)$ can be determined as

$$P_{EQ}(x) = P(x) + \beta^+ P(xy) + \beta^- P(zx)\,, \qquad (3)$$

where, $P(x)$ is active power of the generation/load at phase *x*, $P(xy)$ is active power of the generator/load between phases *x* and *y*, and $P(zx)$ is active power of the generation/load between phases *z* and *x*.

The power flow of the distribution system is modeled using a network flow model in which each phase of a bus is treated as an independent node. In addition, each phase of a branch is treated as a lossless branch, and its flow is only limited by its capacity. For a radial system, the active power flow is easily determined from the values of the load demand and renewable generation. These are given through a backward sweep procedure in which the active power flow on the phase of an upstream branch is determined as the difference between all renewable generations and all load demands on the phase downstream to the branch.

The power supply comes from 1) the power injected from the transmission system at the substation and 2) distributed renewable generation sources at various locations in the distribution system. In this paper, renewable generation is fully utilized unless there is network congestion to prevent doing so, in which case a penalty for the available but unused renewable generations is enacted. We consider various characterizations of loads depending on their flexibility in terms of changing how their demand is met. A load that can be removed partially or completely at a penalty cost is called *a removable load*. A load that can be reduced at an inconvenient cost is called *a reducible load*. A load that can be deferred to a later time, or advanced to an earlier time, is called *a transferable load*. Lastly, a load that is not available for demand response is called *a fixed load* and needs to be serviced immediately.

Under a demand response program, the distribution system operator can determine how to lower reducible loads, drop removable loads, and schedule transferrable loads in order to maintain smoother operations with respect to achieving power balance. Under different demand response scenarios, different values of power need to be drawn at the substation level. There is a cost associated with drawing power at the substation.

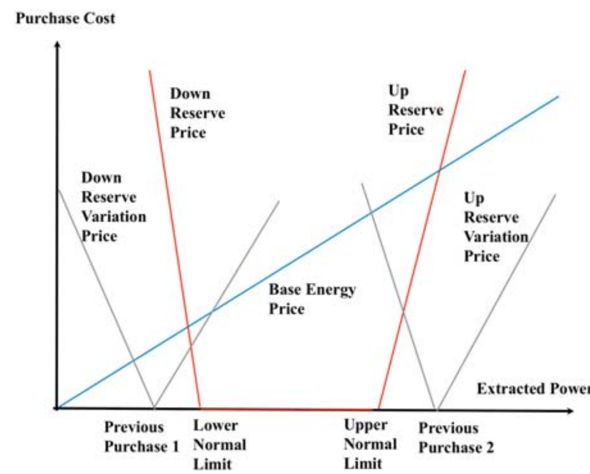

Figure 1. Decoupled price scheme for a substation

As shown in Fig. 1, we propose a cost function based on the sum of three separate pieces. The first component (in blue color) is a linearly increasing cost with respect to extracted power, which represents the base production cost ("Base Energy Price"). The second component (in red color) is a piece-wise linear function that represents the cost of using reserves. The reserve usage cost is zero if the exacted power is within a normal usage range between a lower threshold and an upper threshold, and away from this region, the costs increase linearly ("Down Reserve Price" and "Up Reserve Price"). The third component (in gray color) is also a piece-wise linear function that represents the cost function for variation of reserve usage between two consecutive pricing periods. The reserve variation cost is zero if the amount of up/down reserve to be used at current pricing period is at the same level as ones at previous pricing period. Otherwise the cost is increased with the absolute values of reserve usage variations ("Down Reserve Variation Price" and "Up Reserve Variation Price"). Since the production and reserve costs are given as three separate components, we refer to this as a decoupled pricing scheme. The result of using the decoupled pricing scheme is that it is favorable to less reserve usage and less reverse usage variation. The pricing structure enables us to find demand response solutions that take advantage of this property.

B. Optimal Day-Ahead Operation Model

The day-ahead model determines the operation schedule at each forecast interval for the next 24 hours. It is assumed that the projected prices are given at larger intervals, such as every 60 minutes, than the load demand and renewable energy production forecasts, which are given at relatively shorter intervals, such as every 15 minutes. Therefore, each price period contains several forecast intervals for the load and renewable generation.

First, we discuss the cost function. The objective is to minimize the summation of the purchase cost at the substation C_S, the penalty cost for available but unused renewable generation C_R, and the cost associated with power shedding during a demand response event C_D for all scheduling intervals:

$$\min\ C_S + C_R + C_D . \tag{4}$$

Let H be the set of scheduling hours, $\{Q_h\}_{h\in H}$ be the set of scheduling intervals for each hour h, and Φ_Y is the set of energized phases for a WYE-connected generator/load in the system. If the "Up/Down Reserve" prices are given in terms of consumed energy (kWh), the substation purchase cost is

$$\begin{aligned} C_{S\_kWh} = & \sum_{h\in H, q\in Q_h, x\in\Phi_Y} \alpha_q C_S^0(h,x) P_S(q,x) \\ & + \sum_{h\in H, q\in Q_h, x\in\Phi_Y} \alpha_q \left[\overline{C_S}(h,x)\overline{P_S}(q,x) + \underline{C_S}(h,x)\underline{P_S}(q,x)\right] \\ & + \sum_{h\in H, x\in\Phi_Y} \left[\Delta\overline{C_S}(h,x)\left|\Delta\overline{P_S}(h,x)\right| + \Delta\underline{C_S}(h,x)\left|\Delta\underline{P_S}(h,x)\right|\right], \end{aligned} \tag{5}$$

where, α_q is the ratio of the length of the load/generation forecast interval to the length of the pricing forecast interval. The active power $P_S(q,x)$ at the substation through phase x at interval q is purchased at the base energy price, $C_S^0(h,x)$. The consumed power provided by the "Up/Down Reserves," $\overline{P_S}(q,x)$ and $\underline{P_S}(q,x)$, are determined as

$$\begin{aligned} \overline{P_S}(q,x) &= \max\{0, P_S(q,x) - \overline{P_S^0}(h,x)\}, \\ \underline{P_S}(q,x) &= \max\{0, \underline{P_S^0}(h,x) - P_S(q,x)\}, \end{aligned} \tag{6}$$

where, $\overline{P_S^0}(h,x)$ and $\underline{P_S^0}(h,x)$ are the given thresholds at which the substation is charged with additional "Up/Down Reserve" prices $\overline{C_S}(h,x)$ and $\underline{C_S}(h,x)$. $\Delta\overline{P_S}(h,x)$ and $\Delta\underline{P_S}(h,x)$ are the changes of consumed powers provided by up and down reserves between current and previous pricing periods, and determined as:

$$\begin{aligned} \Delta\overline{P_S}(h,x) &= \sum_{q\in Q_h} \alpha_q \overline{P_S}(q,x) - \sum_{q\in Q_{h-1}} \alpha_q \overline{P_S}(q,x), \\ \Delta\underline{P_S}(h,x) &= \sum_{q\in Q_h} \alpha_q \underline{P_S}(q,x) - \sum_{q\in Q_{h-1}} \alpha_q \underline{P_S}(q,x), \end{aligned} \tag{7}$$

Q_{h-1} is the set of scheduling intervals for hour (h-1), $\Delta\overline{C_S}(h,x)$ and $\Delta\underline{C_S}(h,x)$ are the additional prices for the variations of up and down reserve usages. On the other hand, if the "Up/Down Reserve" prices are given in terms of used capacity (kW/h), then the substation purchase cost is

$$\begin{aligned} C_{S\_kW/h} = & \sum_{h\in H, q\in Q_h, x\in\Phi_Y} \alpha_q C_S^0(h,x) P_S(q,x) \\ & + \sum_{h\in H, x\in\Phi_Y} \left[\overline{C_S}(h,x)\max_{q\in Q_h}\overline{P_S}(q,x) + \underline{C_S}(h,x)\max_{q\in Q_h}\underline{P_S}(q,x)\right] \\ & + \sum_{h\in H, x\in\Phi_Y} \left[\Delta\overline{C_S}(h,x)\left|\Delta\overline{P_S}(h,x)\right| + \Delta\underline{C_S}(h,x)\left|\Delta\underline{P_S}(h,x)\right|\right], \end{aligned} \tag{8}$$

where, the variations of up/down reserve usages are:

$$\Delta\overline{P_S}(h,x) = \max_{q\in Q_h}\overline{P_S}(q,x) - \max_{q\in Q_{h-1}}\overline{P_S}(q,x),$$

$$\Delta\underline{P_S}(h,x) = \max_{q\in Q_h}\underline{P_S}(q,x) - \max_{q\in Q_{h-1}}\underline{P_S}(q,x), \tag{9}$$

The prices are given per phase, allowing for phase balancing to be managed through price signals. Ignoring operation costs, the renewable cost considered in this work is the penalty for not using available renewable energy:

$$C_R = \sum_{h\in H, q\in Q_h, g\in G_R} \alpha_q C^{UN}(g)\left[\sum_{x\in\Phi_Y} P_G^{UN}(g,q,x) + \sum_{xy\in\Phi_D} P_G^{UN}(g,q,xy)\right], \tag{10}$$

where, G_R is the set of local renewable generators (i.e., distributed generation), Φ_D is the set of energized phase pairs of a DELTA-connected generator/load, $C^{UN}(g)$ is the penalty cost per unit unused generation, $P_G^{UN}(g,q,x)$ and $P_G^{UN}(g,q,xy)$ are the active powers of unused generations for generations at phase x, and between phase x and phase y, respectively. The cost for demand responses includes the cost associated with the inconvenience for responsive loads to voluntarily reduce demand, as well as a penalty cost for removable loads to shut off their power supply:

$$\begin{aligned} C_D = & \sum_{h\in H, q\in Q_h, d\in L_{RD}} \alpha_q \left[\sum_{x\in\Phi_Y} C_D^{RD}(d,h,x) P_D^{RD}(d,q,x) + \sum_{xy\in\Phi_D} C_D^{RD}(d,h,xy) P_D^{RD}(d,q,xy)\right] \\ & + \sum_{h\in H, q\in Q_h, d\in L_{RM}} \alpha_q \left[\sum_{x\in\Phi_Y} C_D^{RM}(d,h,x) P_D^{RM}(d,q,x) + \sum_{xy\in\Phi_D} C_D^{RM}(d,h,xy) P_D^{RM}(d,q,xy)\right], \end{aligned} \tag{11}$$

where, L_{RD} and L_{RM} are the sets of reducible and removable loads. $P_D^{RD}(d,q,x)$ and $P_D^{RD}(d,q,xy)$ are the reduced loads at phase x, and between phase x and y. $P_D^{RM}(d,q,x)$ and $P_D^{RM}(d,q,xy)$ are the removed loads at phase x, and between phase x and y. The unit costs for the reduced and removed WYE- or DELTA-connected loads are denoted $C_D^{RD}(d,q,x)$, $C_D^{RD}(d,q,xy)$, $C_D^{RM}(d,q,x)$, and $C_D^{RM}(d,q,xy)$.

Next, we consider the constraints. All energized phases in the system must achieve power balance. For each phase x at each interval q, the system power balance equations are:

$$\begin{aligned} & P_S(q,x) - \sum_{g\in G_R}\left[P_{EQ,G}(g,q,x) - P_{EQ,G}^{UN}(g,q,x)\right] + \sum_{d\in L_{RD}} P_{EQ,D}^{RD}(d,q,x) \\ & + \sum_{d\in L_{RM}} P_{EQ,D}^{RM}(d,q,x) = \sum_{d\in L_{DF}\cup L_{RD}\cup L_{RM}} P_{EQ,D}(d,q,x) + \sum_{d\in L_{DT}, q'\in I_q^{TF}} P_{EQ,D}^{TF}(d,q'q,x), \end{aligned} \tag{12}$$

where, L_{DF} and L_{DT} are the sets of fixed and transferable loads. The set of intervals whose transferable loads have been deferred or advanced to interval q is denoted I_q^{TF}. $P_{EQ,G}(g,q,x)$ and $P_{EQ,G}^{UN}(g,q,x)$ are the active powers of equivalent available renewable generation, and equivalent unused renewable generation at phase x. $P_{EQ,D}^{RD}(d,q,x)$ and $P_{EQ,D}^{RM}(d,q,x)$ are the equivalent reduced and removed loads at interval q and phase x. $P_{EQ,D}^{TF}(d,q'q,x)$ is the equivalent load at interval q transferred from interval q' at phase x. For transferable loads, power consumption may be increased during the transfer due to changes in efficiency amongst different intervals. The second family of constraints concerns achieving power balance in this setting. Let the set of intervals that transferrable loads in interval q are transferred to be denoted I_q^{TO}. The energy balance among recovery periods for each load is given respectively for WYE-connected loads and for DELTA-connected loads as:

$$\sum_{q'\in I_q^{TO}} P_D^{TF}(d,qq',x)\eta(d,qq',x) = P_D(d,q,x),\ \forall x\in\Phi_Y,$$

$$\sum_{q'\in I_q^{TO}} P_D^{TF}(d,qq',xy)\eta(d,qq',xy) = P_D(d,q,xy),\ \forall xy\in\Phi_D,\ (13)$$

$\eta(d,qq',x)$ and $\eta(d,qq',xy)$ are the resulting efficiency factors for transferring load d from interval q to interval q'. The unused energy from a renewable source is constrained by the available renewable output, yielding:

$$\forall g\in G_R, q\in Q_h, h\in H: \quad (14)$$

$$P_G^{UN}(g,q,x)\le P_G(g,q,x),\ \forall x\in\Phi_Y,$$

$$P_G^{UN}(g,q,xy)\le P_G(g,q,xy),\ \forall x\in\Phi_D.$$

Let $\rho^{RD}(d,q,x)$ and $\rho^{RD}(d,q,xy)$ be the maximum ratios of voluntary load reduction at interval q for a WYE-connected and DELTA-connected load d, respectively. Similarly, let $\rho^{RM}(d,q,x)$ and $\rho^{RM}(d,q,xy)$ be the maximum ratios of forced load removals at interval q for a WYE-connected and DELTA-connected load d, respectively. Then, the constraints on the allowed reduced and removed loads are given as:

$$\forall d\in L_{RD}, q\in Q_h, h\in H: \quad (15)$$

$$P_D^{RD}(d,q,x)\le\rho^{RD}(d,q,x)P_D(d,q,x),\ \forall x\in\Phi_Y$$

$$P_D^{RD}(d,q,xy)\le\rho^{RD}(d,q,xy)P_D(d,q,xy),\ \forall xy\in\Phi_D$$

$$\forall d\in L_{RM}, q\in Q_h, h\in H: \quad (16)$$

$$P_D^{RM}(d,q,x)\le\rho^{RM}(d,q,x)P_D(d,q,x),\ \forall x\in\Phi_Y$$

$$P_D^{RM}(d,q,xy)\le\rho^{RM}(d,q,xy)P_D(d,q,xy),\ \forall xy\in\Phi_D.$$

Given the complexity and dimension of the system, only the power flow limits for overloaded branches at specific occurring phases and moments are considered. Consider the power flow on the branch between bus i and bus j: Without loss of generality, let i be the upstream bus and j be the downstream bus. The power flow between i and j can be determined as the sum of power injections for all buses upstream to bus i or the sum of all power injections downstream to bus j due to the radial nature of distribution networks. Accordingly, the power limits are described as:

$$\forall(i,j)\in L^{OV}, q\in Q_h^{OV}, h\in H^{OV}, x\in\Phi_Y^{OV}: \quad (17)$$

$$-\overline{P_{ij}}(x)\le F_{ij}(q,x,B_j^{DN})\le\overline{P_{ij}}(x),$$

$$-\overline{P_{ij}}(x)\le F_{ij}(q,x,B_i^{UP})\le\overline{P_{ij}}(x),$$

where L^{OV}, Q_h^{OV}, H^{OV}, and Φ_Y^{OV} are the sets of overloaded branches, intervals, hours, and phases. The set of buses upstream to the upstream bus i is denoted B_i^{UP}, and the set of buses downstream to the downstream bus j is denoted B_j^{DN}. The maximum allowed active power flow along branch (i, j) at phase x is $\overline{P_{ij}}(x)$, and $F_{ij}(q,x,B)$ is the sum of power injections for the set of buses B.

In order to efficiently solve the above optimization problem, a candidate solution is initially set by omitting the power flow limit constraints in (17). After this candidate solution is obtained, the power flow is calculated using the backward sweep method for radial distribution systems mentioned above. If overloaded lines are present, the problem is resolved using power flow limit constraints on those overloaded branches, yielding a new solution. The process is repeated until a solution is obtained without any overloaded lines. This optimization problem can be solved by computationally efficient linear programming methods.

C. Optimal Real-Time Operation Model

The purpose of a real-time model is to determine the dispatch scheme for the next real-time pricing interval based on the real-time load and generation forecasts. If the real-time prices are given at a small interval, such as every 15 minutes, the load and renewable forecasts can be given at much shorter intervals, such as every 3 minutes. Therefore, the real-time model can include 5 real-time forecast intervals.

Similar to the day-ahead model, the objective to be minimized for a real-time model includes the substation purchase cost, the cost of unused renewable energy, and the demand response cost. The costs for the real-time model follow a similar formula to that given in equations (4)-(11), except instead of considering a set of scheduling hours H and a set of scheduling intervals, Q_h for each $h\in H$, the set of pricing periods is denoted Q, and T_q is the set of forecast intervals for pricing period $q\in Q$. In contrast to the day-ahead model, the real-time model considers the nodal power balance equations as its constraints. For any bus i, the power balance equation is given in equation (18):

$$\delta_i P_S(t,x)+\sum_{g\in G_R(i)}\left[P_{EQ,G}(g,t,x)-P_{EQ,G}^{UN}(g,t,x)\right]-\sum_{j\in N(i)}P_{ij}(t,x)$$
$$+\sum_{d\in L_{RD}(i)}P_{EQ,D}^{RD}(d,t,x)+\sum_{d\in L_{RM}(i)}P_{EQ,D}^{RM}(d,t,x)$$
$$=\sum_{d\in L_{DF}(i)\cup L_{RD}(i)\cup L_{RM}(i)}P_{EQ,D}(d,t,x)+\sum_{d\in L_{DT}(i),t'\in I_t^{TF}}P_{EQ,D}^{TF}(d,t't,x),\ (18)$$

where δ_i is a binary variable, which equals 1 when the substation is located at bus i. The set of neighboring buses to bus i is denoted $N(i)$. $P_{ij}(t,x)$ is active power flowing on the branch between bus i and j at interval t and phase x. All other notation is defined similarly to the day-ahead model. In addition, the energy balance for transferable loads requires the power consumption to remain the same in the real-time model since the efficiency difference between intervals can be ignored, yielding:

$$\forall d\in L_{DT}, t\in T_q, q\in Q: \quad (19)$$

$$\sum_{t'\in I_t^{TO}}P_D^{TF}(d,t't,x)=P_D(d,t,x),\ \forall x\in\Phi_Y,$$

$$\sum_{t'\in I_t^{TO}}P_D^{TF}(d,t't,xy)=P_D(d,t,xy),\ \forall xy\in\Phi_D.$$

The unused renewable energy, allowed voluntarily reduced and forcible removed load, and active power flow limit constraints follow as in the day-ahead case described in equations (14), (15)-(16), and (17), respectively.

III. Numerical Examples

The proposed method has been tested on several systems. Due to space limitation, only the day-ahead optimization results for a 13-bus system are provided in this paper.

The 13-bus system is adapted from the IEEE 13-node test feeder [10]. The 13-node feeder is modified to include a photovoltaic generation at bus 680. Loads at bus 634, 671, and 675 are set as reducible, removable, and transferable loads, respectively. All loads at other buses are fixed loads. Bus 650 is the substation bus that connects the feeder to the main transmission grid, and distribution operation is optimized based on the decoupled prices given for this bus. The 24-hour load and renewable generation profiles used for testing are shown in Figure 2. The load and generation data are provided every 15 minutes. The horizontal axis represents the accumulated number of forecasting intervals, and the vertical axis represents the corresponding scaling factors for loads and generations at each interval with respect to the base generation and base load. The base generation is 300 kW per phase, and the base load is set using the load demands given in [10].

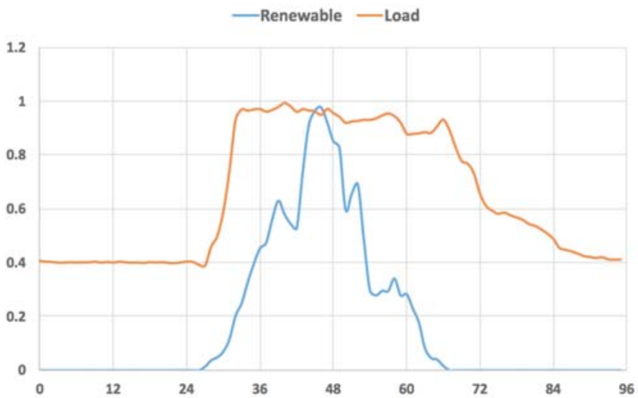

Figure 2. Renewable generation and load profile

The parameters used in the simulations are as follows. The lower and upper normal limits are 500kW and 750kW, respectively. The unused renewable cost is $0.2/kWh, and the prices for load reduction and removal are $0.075/kWh and $0.5/kWh, respectively. The transferable loads are also considered to be deferrable loads, and the time in which a deferrable load can be serviced is limited to a 3-hour period around the originally scheduled time. The transfer efficiency is set to 83.333% for deferred hours.

We have tested three different scenarios in the day-ahead operation setting. As shown in Table I, each test case uses a different pricing scheme. In Case I, a composite price scheme is used in which all power usage is charged at a flat price. In contrast, decoupled price schemes are used for both Case II and Case III. In Case II, only base energy and reserve usage prices are applied. In Case III, all three prices including reserve usage variation price are applied. Table II summarizes the day-ahead optimization results for those three cases. As listed in Table II, all test cases have made full use of renewable, and the total cost for each case is also almost exactly the same. However, the resulting load variations at the substation for different price schemes are significantly different. Taken phase A as example, Case II and III have reduced the substation load variations by 21.15% in comparison with Case I.

TABLE I. SUBSTATION PRICE SCHEMES FOR TEST CASES

Case	**Base Energy Price ($/kWh)**	**Up/Down Reserve Price ($/kW/h)**	**Up/Down Reserve Variation Price ($/kW/h)**
I	0.0625	0.0	0.0
II	0.0600	0.0198	0.0
III	0.0596	0.0198	0.009

TABLE II. SUBSTATION LOAD VARIATIONS, RENEWABLE USAGES AND COSTS

Case	**Total Cost ($)**	**Unused Renew-able(%)**	**Substation Load Variation (kW)**		
			Phase A	Phase B	Phase C
I	2974.35	0	704.23	486.49	663.09
II	2974.50	0	555.28	398.83	543.99
III	2974.33	0	555.28	392.42	535.26

The effectiveness of decoupled schemes on mitigation of substation load variations is further demonstrated in Figure 3. In Fig. 3, the aggregated load profiles at the substation on phase A are given for each test case every 15 minutes. It can be seen that the demand fluctuations at the substation have been effectively reduced using demand responses under the proposed pricing scheme. It is also shown that using an additional price for reserve variation, the aggregated load profile at the substation can be further smoothened.

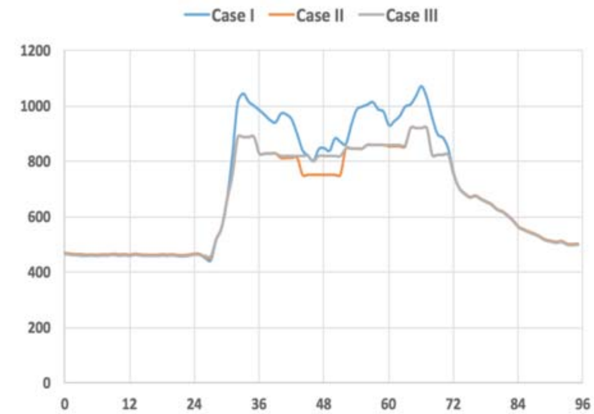

Figure 3. Aggreated Load Profile at the Substation on Phase A

IV. CONCULUSION

With increasing penetration of renewable resources, the demand fluctuations at the substation become more and more important. Instead of trying to control generation in order to smooth out this volatility, we propose using generation following enabled by a decoupled pricing mechanism for demand response. This makes full utilization of renewable, but also reduces the need for reserve unit power production.

REFERENCES

[1] J. Morales, A. Conejo, and J. Perez-Ruiz, "Economic Valuation of Reserves in Power Systems With High Penetration of Wind Power," *Power Systems, IEEE Transactions on,* vol. 24, no. 2, pp. 900–910, May 2009.

[2] J. Zarnikau, "Demand Participation in the Restructured Electric Reliability Council of Texas Market," *Energy,* vol. 35, no. 4, pp. 1536–1543, 2010.

[3] P. Cappers, C. A. Goldman, and D. Kathan, "Demand Response in U.S. Electricity Markets: Empirical Evidence," *Energy,* vol. 35, no. 4, pp.1526–1535, 2010.

[4] J. Torriti, M. G. Hassan, and M. Leach, "Demand Response Experience in Europe: Policies, Programmes and Implementation," *Energy,* vol. 35, no. 4, pp. 1575 – 1583, 2010.

[5] M. Caramanis and J. Foster, "Coupling of Day Ahead and Real-Time Power Markets for Energy and Reserves Incorporating Local Distribution Network Costs and Congestion," in *Communication, Control, and Computing (Allerton), 2010 48th Annual Allerton Conference on*, Sept 2010, pp. 42–49.

[6] N. Paterakis, J. Catalao, A. Ntomaris, and O. Erdinc, "Evaluation of Flexible Demand-Side Load-Following Reserves in Power Systems with High Wind Generation Penetration," in *PowerTech, 2015 IEEE Eindhoven,* June 2015, pp. 1–6.

[7] E. Karangelos and F. Bouffard, "Towards Full Integration of Demand-Side Resources in Joint Forward Energy/Reserve Electricity Markets," *Power Systems, IEEE Transactions on,* vol. 27, no. 1, pp. 280–289, Feb 2012.

[8] F. Galiana, F. Bouffard, J. Arroyo, and J. Restrepo, "Scheduling and Pricing of Coupled Energy and Primary, Secondary, and Tertiary Reserves," *Proceedings of the IEEE,* vol. 93, no. 11, pp. 1970–1983, Nov 2005.

[9] J. Morales, A. Conejo, K. Liu, and J. Zhong, "Pricing Electricity in Pools With Wind Producers," *Power Systems, IEEE Transactions on,* vol. 27, no. 3, pp. 1366–1376, Aug 2012.

[10] "Distribution Test Feeders: IEEE PES," http://www.ewh.ieee.org/soc/pes/dsacom/testfeeders/index.html, Sept 2010.