J Electr Eng Technol.2017; 12(6): 2127-2137
http://doi.org/10.5370/JEET.2017.12.6.2127

ISSN(Print) 1975-0102
ISSN(Online) 2093-7423

Local-Generator-Based Virtual Power Plant Operation Algorithm Considering Operation Time

Sung-Won Park*, Yong-Gi Park and Sung-Yong Son†**

Abstract - A virtual power plant (VPP) is a system that virtually integrates power resources based on the VPP participating customer (VPC) unit and operates as a power plant. When VPP operators manage resources to maximize their benefits, load reduction instructions may focus on more responsive VPCs, or those producing high profitability, by using VPC resources with high operation efficiency. VPCs may thus encounter imbalance problems during operation. This imbalance in operation time would bring more participation for some VPCs, causing potential degradation of their resources. Such an operation strategy would be not preferable for VPP operators in managing the relationship with VPCs. This issue impedes both continual VPC participation and economical and reliable VPP operation in the long term. An operation algorithm is therefore proposed that considers the operation time of VPC generators for mandatory reduction of power resource consumption. The algorithm is based on constraints of daily and annual operation times when VPP operators of local generators perform capacity-market power transactions. The algorithm maximizes the operator benefit through VPP operations. The algorithm implements a penalty parameter for imbalances in operation times spent by VPC generators in fulfilling their obligations. An evaluation was conducted on VPP operational effects by applying the algorithm to the Korean power market.

Keywords: Virtual Power Plant (VPP), Optimal operation algorithm, Equality operation, Operation time, Local generator

1. Introduction

A virtual power plant (VPP) is a system that integrates various power resources based on the consumer unit and operates as a power plant. VPP is a comprehensive concept that includes an existing demand response (DR). Accordingly, power resources from the demand side are recognized as generation resources on equal terms [1, 2]. VPP consists of resources distributed on a small scale. Thus, the number of systems for systematic VPP management and connection tends to be insufficient. For this reason, the role of VPP operators is crucial in connecting distributed resources, such as the VPP, and optimally operating them according to the systems and market circumstances.

There have been many studies on the optimal operation of VPP [2-11]. Most studies on VPP operations have focused on maximizing the operator benefit and minimizing the operation cost considering various VPP resources such as PV, wind, generator, and load) [2-5]. Additional cost factors have been considered to increase model accuracy. A methodology for maximizing the profit of VPP owners based on nodal pricing of distribution networks considering the required reserve is studied in [6]. A VPP optimal bidding method considering the uncertainty of price and generation sources in a day-ahead market is explored [7]. A risk factor that affects daily operation profit and proposed a two-stage stochastic mixed integer linear programming model for optimal operation in a day-ahead and balancing market is also studied [8]. Game theory is used to solve the bidding strategy problem for VPP by considering uncertainties of DR and DER owner resource such as renewable, electricity price, load, and losses allocation in some studies [9, 10]. A micro CHP (μCHP) is also considered an additional resource in [11]. The result showed that using μCHP with heat and electrical storage can facilitate the scheduling.

The results of these studies can be effectively applied to solve problems on reducing the amount of power resources targeted by VPP operators or on maximizing their benefits. However, when operators manage the VPP to maximize their profits, instructions on VPP power consumption reduction may focus on specific VPP participating customers (VPCs) who have cost effective resources. It can also be focused on the VPCs to have high reliability of power reduction and response. In this case, VPCs can have issues related to the imbalance in the operation time. This imbalance in operation time would bring more participation for some VPCs, causing potential degradation of their resources such as local generators, energy storage systems (ESSs), etc. Such an operation strategy would be

† Corresponding Author: Dept. of Electrical Engineering, Gachon University, Korea. (xtra@gachon.ac.kr)
* Dept. of Electrical Engineering, Gachon University, Korea. (trueming@gachon.ac.kr)
** Dept. of Electrical and Electronic Engineering, Youngsan University, Korea. (draco.park@ysu.ac.kr)
Received: July 19, 2016; Accepted: July 18, 2017

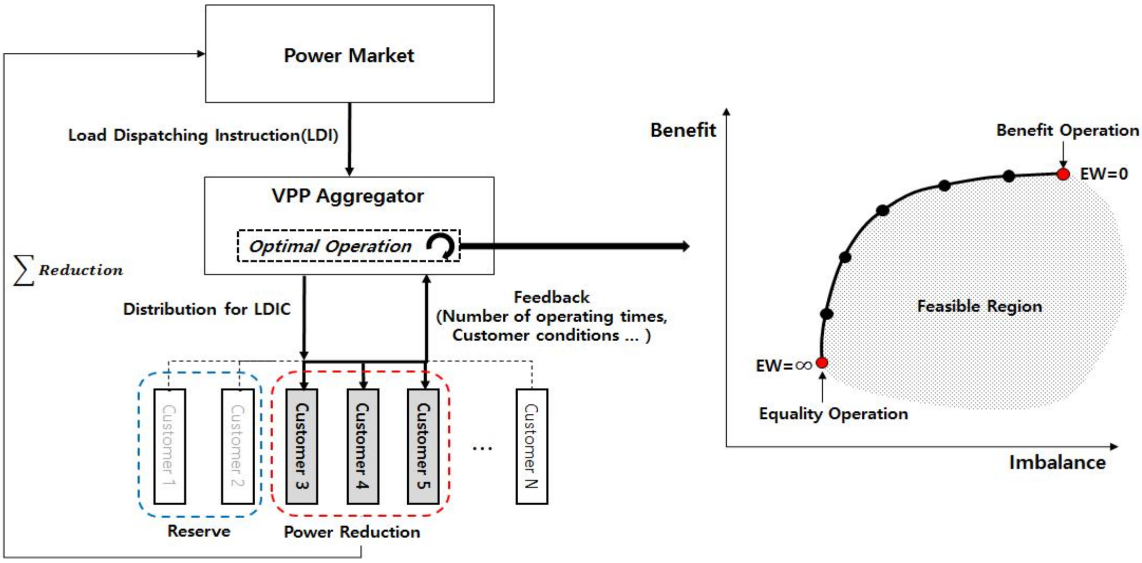

Fig. 1. Diagram of the VPP and the concept of the proposed optimal operation algorithm

not preferable for VPP operators in managing the relationship with VPCs. This impedes both the continual participation of VPCs and economical and reliable VPP operations in the long term. Thus, the operation time required by VPCs to fulfill their obligations should be considered in establishing an effective operation plan.

Unlike typical bulk generators, a local generator of VPP resources (i.e., fuel, gas, and combine heat and power(CHP)) is one that is used to manage peak loads or Sin emergency cases, such as blackouts. Thus, a constraint exists based on operation and power market regulations in terms of the time required for its daily operations in accordance with the types of fuel supply units used. Moreover, VPP operators should spend a specific time in performing their duties to reduce the power consumption during a contract period with the power market. Consequently, constraints in operating time arise during the contract period between VPP operators and VPC generators. These constraints can increase the imbalance in operation time spent by VPC generators for mandatory reduction of power consumption. An operation plan that considers these constraints should be established for effective operation of the VPP based on local generators.

In this study, an optimal operation algorithm is proposed that considers the amount of time spent by VPC generators for mandatory reduction of power resource consumption under the constraints of daily and annual operation times. These times are specifically those when VPP operators based on local generators, perform power transactions in the capacity market. The algorithm serves to maximize the profits of operators through VPP operations. It implements a penalty parameter to consider the imbalance in the time spent by VPC generators in fulfilling their obligations. The imbalance penalty parameter is based on the operation time of VPC generators. It is calculated by using an imbalance index based on the mean absolute deviation (MAD) and weight cost. In addition, the operational effects according to the degree of equality in the time spent by the VPC generators for fulfilling their obligations are compared by applying this algorithm to the Korean power market.

2. Local-Generator-Based VPP Model Considering Equality Index

Among the various types comprising the VPP, the centralized controlled VPP (CCVPP) is the most typical type. It includes several distributed resources at a lower level based on a management system [12, 13]. A VPP based on local generators with the CCVPP structure consists of numerous VPC generators at a lower level. It additionally consists of a power market that performs power transactions and gives instructions on power reductions at a higher level based on the VPP operator. A power market stabilizes power demand and supply by providing load dispatching instructions (LDI) to a VPP operator in accordance with contract conditions in emergency cases. The VPP operator who receives the LDI reduces its capacity (LDIC) that is allocated through its distribution among VPCs. Here, LDI is an instruction for load reduction given by a power market operator to VPP operators. LDIC is the mandatory load reduction amount of the VPP operator. Fig. 1 presents a diagram of the VPP and the concept of the proposed algorithm. The conceptual diagram of the algorithm in the figure depicts the relationship between the benefit and equality operation. The VPP operator establishes an operation plan by considering the feasible decision space in which the power use reduction can satisfy the LDIC allocated from the power market. If the benefits are emphasized in the process of establishing the operation plan, the schedule is set based on the generator that exhibits a high operation efficiency to increase the profits. However, the power-reduction instructions focus on a certain generator that exhibits high efficiency. therefore, an imbalance in the operation time spent for the reduction can occur. On the other hand, when the VPP operates with an emphasis on equality, the operating time of the generators can be evenly maintained. However, the benefit of VPP operators may decrease because a generator that exhibits low operation efficiency is being operated. A multi-objective optimization problem (MOP) occurs in terms of the discordance between the two operational goals of the optimization directions discussed above. Thus, an optimal alternative should be selected by practically conducting a post-hoc comparison on the optimization results. To this end, the proposed approach implements an imbalance penalty that affects the aggregator's benefit in terms of equality-oriented operations. The imbalance penalty is calculated based on an imbalance index that indicates the degree of imbalance and the equality weight (EW). When EW is 0, the VPP operation has the maximum benefit, which increases the operation imbalance accordingly. Conversely, when EW is ∞, the VPP operation has minimum imbalance, which decreases the operation than EW 0 accordingly.

3. Capacity Market in Korea

A DR program is a main method that VPP operators use to recruit VPCs and perform power transactions. DR programs are largely classified into those based on incentives (i.e., capacity market, demand bidding, and ancillary service markets), and those based on cost (i.e., time of use, critical peak pricing, and real-time pricing) [14-16]. The market-based DR program has been widely executed in Korea. It mainly consists of demand bidding, whereby the bid prices of the demand resources are established as being equivalent to those of the generation resources in the day-ahead market and capacity market. Accordingly, it maintains the balance in the power demand and supply and the stable operation of the power system. The VPP operator can participate in the power market as a demand response resource (DRR) by recruiting the VPCs that will reduce their electric power loads in accordance with power-market operation regulations. It also requires that the VPP operator registers the obligation reduction capacity between 10 and 500 MW based on 10 VPCs or more.

The VPP operator registered as a DRR should be required to participate in the capacity market. Moreover, that operator should be qualified to participate in demand bidding. This study focuses on the capacity market in Korea. In the capacity market, the market operator can allocate the LDI based on the obligation reduction capacity registered by the VPP operator. The LDI can be provided up to twice per day. The duration of time required for the power reduction of 2 to 4 h is applied per LDI. The LDI can be issued within 60 h per year. The VPP operator receives a penalty when the amount of power resources reduced is 70 % or less of the LDIC.

Table 1. Main contents of power market operation regulations in Korea

Item	Detail
Obligation reduction capacity	Over 10 MW and below 500 MW
Number of VPCs	Ten or higher
Dispatched capacity	Lower than obligation reduction capacity
Duration time for reduction	2h at the minimum and 4h at the maximum
Maximum number of LDI per day	Twice
Maximum time for the LDI per year	60 h
Maximum acceptable amount of power reduced	LDIC X 1.2
Method of settlement	Based on CBL

Furthermore, the VPP operator is rewarded with a basic settlement based on the registered obligation reduction capacity. The reduction-related settlement amount is based on the amount of power resource reduction. The amount of power resources reduced by the VPP operator compared to the LDI is calculated by considering the customer baseline (CBL) and measured real load. Table 1 outlines the main contents of power-market operation regulations in Korea [17].

4. Problem Formulation

4.1 Objective function

The objective function proposed in this study maximizes the operator's benefit. It can be formulated based on the difference between the benefit from the VPP operation and the imbalance penalty, as shown (1).

$$\sum_{t\in T}\sum_{j\in C} OP_{j,t}\left[L_{j,t}^{R}\cdot PR_{t}^{R}-\left(\mathrm{OC}_{j,t}+SUC_{j,t}\right)\right]-\lambda\cdot IMI \quad (1)$$

where,

$$IMI=\frac{1}{N}\sum_{j=1}^{N}A_j^{Dev}, \qquad \forall j\in C$$

$$A_j^{Dev}=\left|x_j-x'\right|, \qquad \forall j\in C$$

$$x_j(\%)=100\,(\sum_{t\in T} OP_{j,t}+CNT_j^{TOTAL})/CST_j^{YOT}, \qquad \forall j\in C$$

The imbalance penalty is calculated by multiplying the imbalance index (IMI) and EW (λ). In this study, the IMI was determined by using the mean absolute deviation (MAD) to quantify the degree of equality. Here, x_j and x' in MAD are the j[th] participant's operation rate and their mean value, respectively, which is the ratio of the operation time to the annual contracted maximum operation time, as defined in (1). EW (λ) is penalty parameter of the imbalance operation time as well as an input value determined by the VPP operator. When the value of λ is 0, the schedule oriented toward the maximum benefit is derived.

On the other hand, when the value of λ is above 0, a penalty occurs on account of IMI. Here, the imbalance among participants is defined as IMI shown in (1). MAD-based IMI is represented as an absolute value and is applied to the objective function, as shown in (1). In this study, MAD is linearized by using two variables of x_j^+ and x_j^- to solve the mixed integer linear programming (MILP) problem, as shown in (2) and (3)-(5) to indicate the constraints on the linearization. Here, x_j^+ and x_j^- are the positive and negative deviation of operation time, respectively.

$$\sum_{t\in T}\sum_{j\in C} OP_{j,t}[L_{j,t}^R \cdot PR_t^R - (OC_{j,t}+SUC_{j,t})] - \lambda \cdot [\frac{1}{N}\sum_{j\in C}(x_j^+ + x_j^-)] \quad (2)$$

$$(x_j^+ + x_j^-) - A_j^{Dev} = 0, \quad \forall j\in C \quad (3)$$

$$x_j^+ \geq 0, \quad \forall j\in C \quad (4)$$

$$x_j^- \geq 0, \quad \forall j\in C \quad (5)$$

4.2 Constraints on operation time available per day and year

As described in Section 1, power market regulations generate constraints on available daily and annual operation times. In this study, the constraints on these times are applied to effectively operate the VPP. First, the constraints on the available daily operation time can be formulated as the operation and suspension binary variable ($OP_{j,t}$) of the j[th] generator, which cannot exceed the available daily maximum operation time (CST_j^{DOT}) during the period (T) of establishing the VPP schedule, as shown in (6).

The constraints on the available annual operation time can be formulated as the following: the sum of $OP_{j,t}$ and the accumulated amount (CNT_j^{TOTAL}) of the previous operation time of the j[th] generator cannot exceed the available annual maximum operation time (CST_j^{YOT}). This is shown in (7).

$$\sum_{t\in T} OP_{j,t} \leq CST_j^{DOT}, \quad \forall j\in C \quad (6)$$

$$\sum_{t\in T} OP_{j,t} + CNT_j^{TOTAL} \leq CST_j^{YOT}, \quad \forall j\in C \quad (7)$$

4.3 Constraints on power demand and supply

The constraints on demand and supply in terms of the LDI issued from the power market can be represented by using the total sum of the amount ($L_{j,t}^R$) of loads reduced by the VPCs and the LDIC (D_t) according to time. This is expressed in (8). W^D is the weight that indicates the amount of power reduced by the VPP operator. It can be accepted as the maximum amount based on the LDIC. The amount ($L_{j,t}^R$) of loads reduced by the VPCs can be derived based on the difference between the CBL of the j[th] VPCs and the loads after reduction (i.e., the amount of loads used minus the amount generated), as shown in (9).

$$D_t \leq \sum_{j\in C} OP_{j,t} \cdot L_{j,t}^R \leq D_t \cdot W^D, \quad \forall t\in T \quad (8)$$

$$L_{j,t}^R = [L_{j,t}^{CBL} - (L_{j,t}^{CUS} - P_{j,t})], \quad \forall j\in C, \forall t\in T \quad (9)$$

4.4 Constraints on the output of local generator

The modes of local generators are classified into load-following output, constant output, and variable output modes according to the operation types. In the load-following output mode, the generation output is determined according to the load ($P_{j,t}^{LG}$) connected to the generator, as shown in (10). In the constant output mode, the generation output is determined by the fixed output ($P_{j,t}^{CG}$) set by the VPCs, as shown in (11). In the variable output mode, the output is determined between the minimum generation ($P_{j,t}^{Min}$) and maximum generation ($P_{j,t}^{Max}$) of the VPCs, as shown in (12).

$$P_{j,t} = P_{j,t}^{LG} \cdot OP_{j,t}, \quad \forall j\in LG,\ LG\in C \quad (10)$$

$$P_{j,t} = P_{j,t}^{CG} \cdot OP_{j,t}, \quad \forall j\in CG,\ CG\in C \quad (11)$$

$$P_{j,t}^{Min} \cdot OP_{j,t} \leq P_{j,t} \leq P_{j,t}^{Max} \cdot OP_{j,t}, \forall j\in VG,\ VG\in C \quad (12)$$

4.5 Operation cost for the local generator

4.5.1 Operation cost

The fuel cost according to the output of the local generator can be represented by a quadratic function, as shown in (13). α_j, β_j, and γ_j refer to the characteristic functions of the j[th] generator in terms of fuel cost, and P_j refers to the output of the j[th] generator of the VPCs at the time of *t* [18, 19].

$$OC_{j,t} = \alpha_j (P_{j,t})^2 + \beta_j (P_{j,t}) + \gamma_j \quad (13)$$

Eq. (13) is represented in the form of a non-linear function and should be approximated by a linear function to solve the MILP. In this study, a piecewise linear function is used for accurate fuel cost modeling for the j[th] generator as shown in (14)-(18) [20, 21].

$$OC_{j,t}=\left[\alpha_j(P_j^{Min})^2+\beta_j(P_j^{Min})+\gamma_j\right]+\sum_{l=1}^{NL_j}B_{jl}\cdot P_{jl,t},\ \ \forall j\in C,\forall t\in T \quad (14)$$

$$P_{j,t}=OP_{j,t}\cdot P_j^{Min}+\sum_{l=1}^{NL_j}P_{jl,t},\quad \forall j\in C,\forall t\in T \quad (15)$$

$$0\le P_{j1,t}\le S_{j1}-P_j^{Min},\quad l=1,\ \forall j\in C,\forall t\in T \quad (16)$$

$$0\le P_{jl,t}\le S_{j1}-S_{jl-1},\ \ l=2,..(NL_j-1),\ \forall j\in C,\forall t\in T \quad (17)$$

$$0\le P_{jl,t}\le P_j^{Max}-S_{jl}\ \ l=NL_j,\ \forall j\in C,\forall t\in T \quad (18)$$

4.5.2 Start-up and shut-down costs

When a generator starts up or shuts down, the respective costs are incurred on account of fuel consumption. When the generator operates, the start-up cost is classified into a hot-start cost and a cold-start cost according to the shut-down time. This is expressed in (19) [22, 23].

$$SUC_{j,t}=HSC_j+CSC_j\left[1-exp\left(-\frac{TD_{j,t}}{\rho_j}\right)\right] \quad (19)$$

Because (19) is represented as a non-linear function, it should be linearized to solve the MILP. In this study, this equation is converted into linear form by using $OP_{j,t}$ represented as a binary variable and UK_j^n approximated by using a step function, as shown in (20) and (21) [21]. Equations (22) and (23) indicate the suspension cost for the j[th] generator at time *t*. They are represented by using the shut-down cost (DK_j) for each generator and $OP_{j,t}$.

$$SUC_{j,t}\ge UK_j^n\left[OP_{j,t}-\sum_{i=1}^{n}OP_{j,t\text{-}n}\right],\quad \forall j\in C \quad (20)$$

$$SUC_{j,t}\ge 0,\quad \forall j\in C,\forall t\in T \quad (21)$$

$$SDC_{j,t}\ge DK_j\left[OP_{j,t\text{-}1}-OP_{j,t}\right],\quad \forall j\in C,\forall t\in T \quad (22)$$

$$SDC_{j,t}\ge 0,\quad \forall j\in C,\forall t\in T \quad (23)$$

4.6 Operational constraints on the local generator

Minimum up time (MUT) and minimum down time (MDT) are required when a generator operates and stops, respectively. Thus, MUT and MDT should be considered to establish an operation plan that considers the physical properties of the generator. As shown in (24) and (25), MUT and MDT can be represented by using a variable ($K_{j,t}$) of the operation or the stop time of the j[th] generator until the time of *t* and $OP_{j,t}$ of the j[th] generator at the time of *t* [20].

$$\left(K_{j,(t-1)}-MUT_j\right)\left(OP_{j,(t-1)}-OP_{j,t}\right)\ge 0 \quad (24)$$

$$\left(K_{j,(t-1)}+MDT_j\right)\left(OP_{j,t}-OP_{j,(t-1)}\right)\le 0 \quad (25)$$

In this study, non-linear (24) and (25) are represented to be linear by referencing [21], as shown in (26) to (31).

4.6.1 Minimum Up Time (MUT)

$$\sum_{t=1}^{IU_j}(1-OP_{j,t})=0,\quad \forall j\in C,\forall t\in T \quad (26)$$

$$\sum_{q=t}^{t+MUT_j-1}OP_{j,q}\ge MUT_j\left(OP_{j,t}-OP_{j,t\text{-}1}\right),\ \ \forall j\in C,\forall t=(IU_j+1),..,(T-MUT_j+1) \quad (27)$$

$$\sum_{q=t}^{T}\left[OP_{j,q}-\left(OP_{j,t}-OP_{j,t\text{-}1}\right)\right]\ge 0,\ \ \forall j\in C,\forall t=(T-MUT_j+2),..,T \quad (28)$$

4.6.2 Minimum Down Time (MDT)

$$\sum_{t=1}^{ID_j}OP_{j,t}=0,\quad \forall j\in C,\ \forall t\in T \quad (29)$$

$$\sum_{q=t}^{t+MDT_j\text{-}1}(1-OP_{j,q})\ge MDT_j\left(OP_{j,t\text{-}1}-OP_{j,t}\right),\ \ \forall j\in C,\forall t=(ID_j+1),..,(T-MDT_j+1) \quad (30)$$

$$\sum_{q=t}^{T}\left[(1-OP_{j,q})-\left(OP_{j,t\text{-}1}-OP_{j,t}\right)\right]\ge 0,\ \ \forall j\in C,\forall t=(T-MDT_j+2),..,T \quad (31)$$

MUT and MDT in the above equations are classified into three sections to determine the status of the generator at the initial, middle, and end points during the creation of the schedule. IU_j and ID_j in (26) and (29) refer to the time required for the initial operation or the stopping of the j[th] generator. They consider the status of the generator at the time before the schedule is established.

The equation considering MUT and MDT at the middle point is represented as in (27) and (30). MUT and MDT at $(IU_j+1),..,(\mathrm{T}-MUT_j+1)$, $(ID_j+1),..,(\mathrm{T}-MDT_j+1)$ are considered, respectively. The equation considering MUT and MDT at the end point is represented in (28) and (31). MUT and MDT at $(T-MUT_j+2),..,T$ and $(T-MDT_j+2),..,T$ are considered, respectively.

5. Case Study

5.1 Simulation design

In the conducted VPP simulation, 50 VPCs were used.

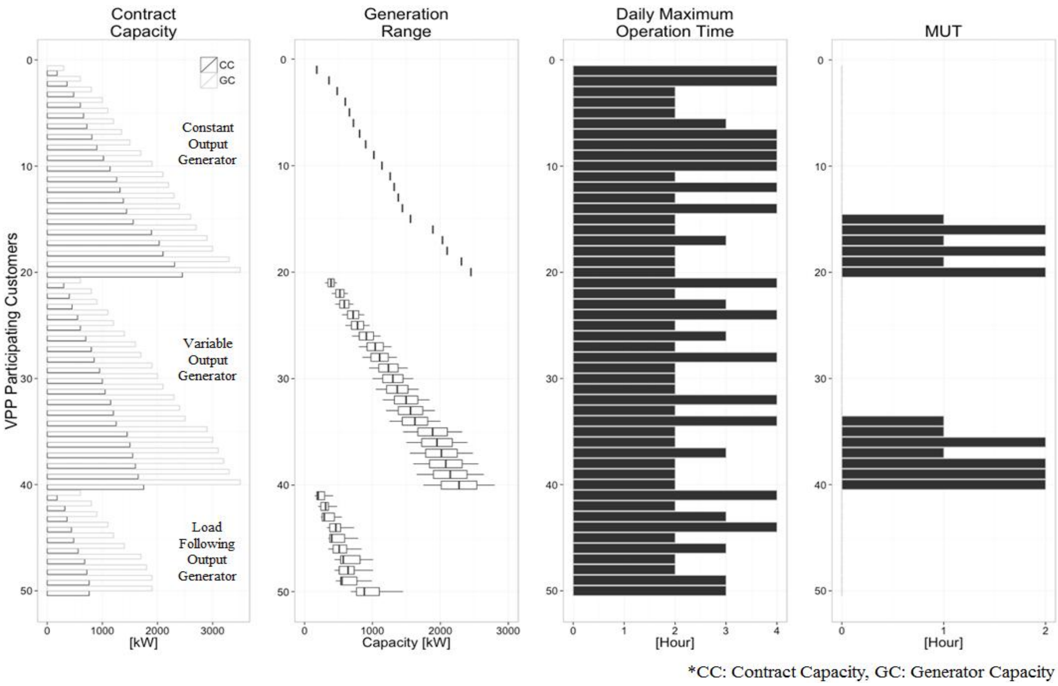

Fig. 2. Overview of main simulation settings

Table 2. Overview of main simulation settings

Item		Detail
VPP participating customer		50
Obligation reduction capacity		40,000 kW
Type of local generator		Diesel, Gas
Capacity of local generator according to the operation types	Load -following mode output generator	40% of the generator capacity
	Constant output mode generator	70% of the generator capacity
	Variable output mode generator	50% to 80% of the generator capacity
Ramp up/down of variable output generators		None
MUT/MDT		1 to 2 h/less than one h
Start-up cost		0% to 5%
Shut-down cost		None
Daily maximum operation time		2 to 4 h
Annual maximum operation time		Daily maximum operation time×Annual maximum operation day (15 days)
Information on the LDI		4 h per day x 15 days (60 h total)
LDIC		16,000 to 36,000 kW (40% to 90%)
Unit cost for fuel		Fuel: 1,600 (KRW/L) Gas: 18 (KRW/MJ)
Unit cost for basic settlement		64,000 KRW/kW
Unit cost for reduction-related settlement		550 KRW/kWh

The entire obligation reduction capacity was established as 40,000 kW. The VPP operation scheduling interval was set to 1 hour. Diesel and gas generators were set as the local generators of the VPCs, and their capacity was between 300 kW and 3,500kW. Practical load patterns were applied for the VPCs. The load capacities were adjusted to be greater than those of the generators by two to four times. The VPC load pattern was applied to the connecting load of the load-following mode generator. The load capacity was set to 40% of the generator capacity. The load capacity of the constant output mode generator was set to 70% of the generator capacity. The min/max of the variable output mode generator were established as 50% and 80% of the generator capacity, respectively.

For the operation efficiency of the local generator, the hourly fuel consumption according to the load capacity was examined and applied. Specifically, it was based on the output capacity of diesel generator manufacturers. For the generators with the capacity of 2,500 kW or more, MUTs of 1 and 2 hours were applied considering their characteristics. The MDTs of all generators were assumed to be less than one hour. The start-up cost was assumed to be 0% to 5% of the generator capacity by considering the characteristics of low-capacity local generators (the shut-down cost was ignored).

The daily maximum operation time for the VPC generators was set to 2 to 4 h per LDI. According to the Korea power market operation regulations, LDI can be issued for up to 4 hours a day and can be issued up to 60 hours a year [18]. In this study, it is assumed that LDI can be issued up to daily maximum operation time × annual maximum operation days for each VPC. Here, 15 days are used for the annual maximum operation days.

In addition, the mean of fuel and gas costs in 2013 in Korea was established as the fuel cost [18]. 64,000 KRW/kW and 550 KRW/kWh were applied as the unit cost of basic settlement and reduction-related settlement, respectively, by referencing the data released by KPX in

2013. IBM ILOG CPLEX was used as the optimization solver. Table 2 and Fig. 2 outline the main simulation settings.

5.2 Simulation and discussion

A simulation was performed by adjusting LDIC and EW based on the above conditions. Fig. 3 shows the optimal benefit point of the VPP operator as the weight increases according to the LDIC. As shown in the figure, when the VPP is operated by considering the maximum benefit (EW 0) of the operator, IMI decreases based on a certain LDIC on account of the operation efficiency and available daily operation time. When the LDI with a capacity of 50% to 70% (20,000 kW to 28,000 kW) of the maximum LDIC (ORC) of 40,000 kW is issued, the imbalance ratio is the highest at approximately 50%. The LDIC is higher or lower based on when it is issued. Specifically, IMI is the highest when the LDIC of 50% to 70% is issued because this value is affected by the result of inputting certain VPC generators that exhibit high operation efficiency. When the LDIC is 50% or lower, IMI decreases, despite the inputting of certain VPC generators that exhibit high operation efficiency. This result is obtained because the time of inputting and operating the generator decreases on account of a relatively low LDIC. When the LDIC is 80% or higher, IMI decreases because diesel generators that exhibit lower

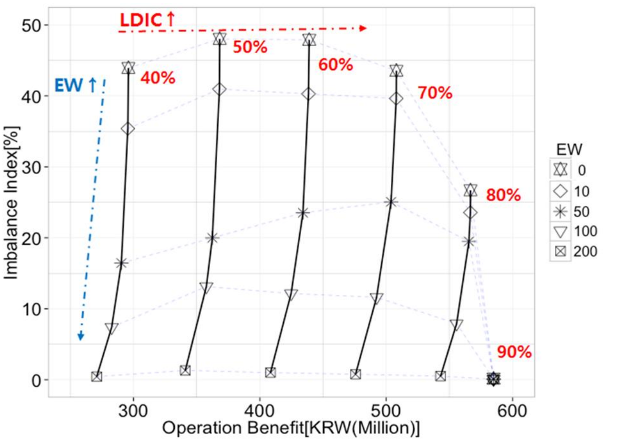

Fig. 3. Optimal benefit point of the VPP operator as the EW increases according to the LDI

Table 3. IMI and input ratio of VPC generators according to the LDIC when the VPP are operated to maximize the benefit (EW 0)

Item / LDIC	IMI (%)	Total input ratio of generators (%)	Gas (%)	Diesel (%)
40%	44.5	34	42.5	0
50%	48.0	48	60	0
60%	47.9	62	77.5	0
70%	43.5	68	85	0
80%	26.7	94	100	70
90%	0.01	100	100	100

operation efficiency are inputted to satisfy the LDIC.

When the LDIC is 90%, IMI becomes closer to 0% because all the generators are operated to fulfill the LDIC. This means that the VPP operator should establish an operation schedule considering IMI when the LDI whose capacity is 90% of the registered capacity or less is issued. Table 3 and Fig. 4 indicate IMI and the input ratio of generators when the VPP is operated to maximize the benefit (EW 0).

The result of examining the changes in IMI according to a decrease in EW verifies that IMI in all cases decreases as EW increases. It additionally indicates that an operation based on the equality of 98.7 % (IMI 2.3%) or higher is performed in all cases when EW is 200 million. Fig. 3 shows that EW between 10 million and 50 million significantly varies when the LDIC is low, and that IMI between 50 million to 100 million significantly changes when LDIC is high. In other words, lower EWs (i.e., 10 million to 50 million) are affected by a lower LDIC, and higher EWs (i.e., 50 million to 100 million) are affected by a higher LDIC. This is because the full benefit of the VPP operator, which is obtained from the amount of power reduced, decreases as LDIC decreases.

To maximize the profit of a VPP operator, IMI should decrease when EW increases, as shown in (1). The simulation results show that the utilization of less efficient VPC generators is increased. Fig. 5 shows the operation rate changes of VPC generators with respect to LDIC EW increments. With low EW values, operations are concentrated on some VPC generators that have high generation efficiency. However, with a high EW increase, 40% to 50% of VPC generators used are diesel generators with low generation efficiency. For the resulting value of 200 million for EW, it is evident that all generators are evenly operated.

The amount of power resources to be reduced by the VPP operator increases as the LDI increases, thereby increasing the benefit. When the operator manages the

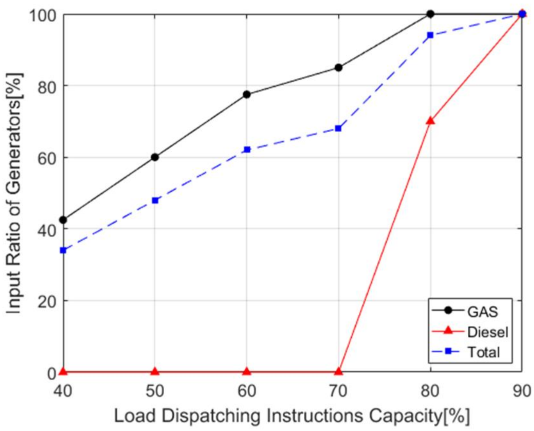

Fig. 4. Input ratio of VPC generators according to the LDIC when the VPP are operated to maximize the benefit (EW 0)

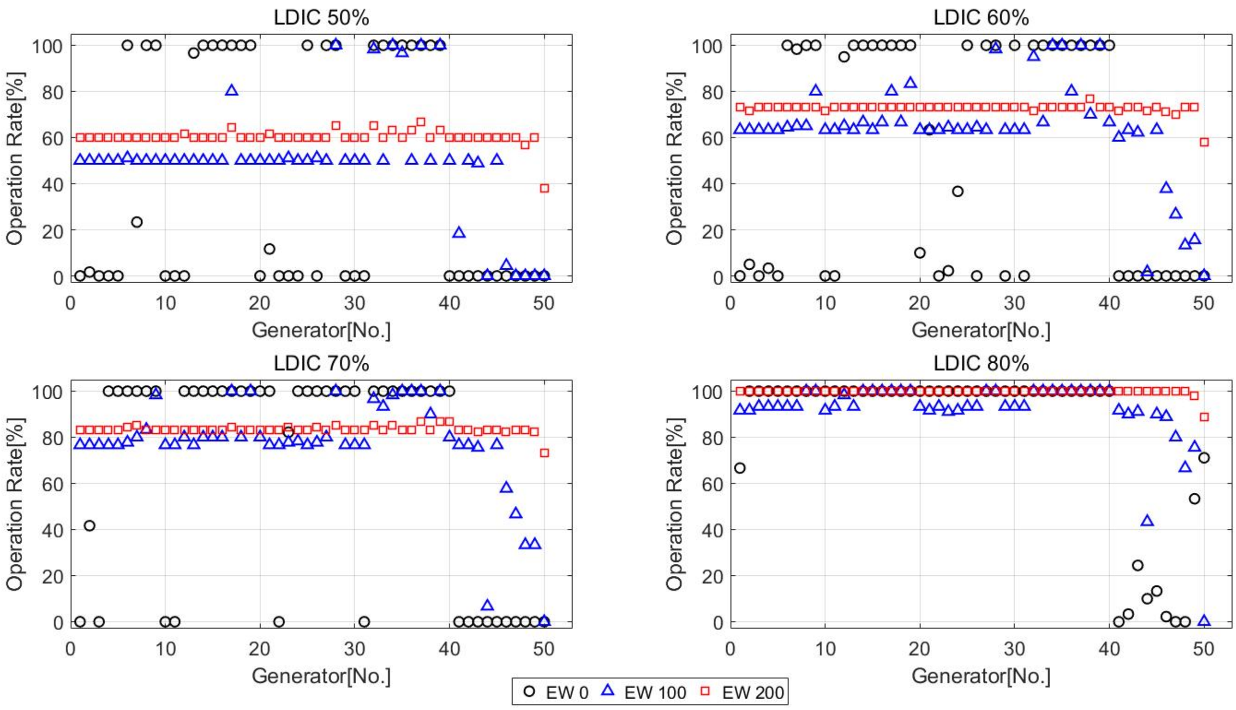

Fig. 5. Operation rates of VPC generators according to the LDIC with different EW values

Table 4. Operation benefit of the VPP operator according to EW and LDIC (million KRW)

EW (million)	LDIC			
	50%	60%	70%	80%
0	368.3	439.1	508.1	566.7
10	368.1	438.5	508.0	566.6
50	362.4	434.1	503.9	565.5
100	357.7	424.8	492.4	555.7
200	341.0	408.4	475.8	543.0

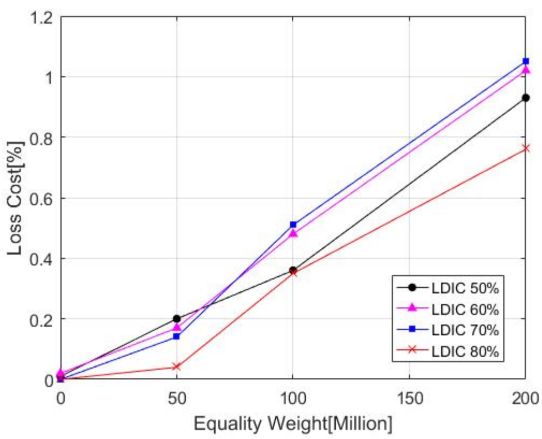

Fig. 6. Trend of changes in the economic loss rate of the VPP operator when EW increases

VPP to maximize the benefit (EW 0), the LDIC of 50% generates the benefit of approximately 368.3 million KRW; the LDIC of 90% generates approximately 584.9 million KRW. These results are indicated in Table 4. On the other hand, when the operator performs even VPP operations, an increase in EW requires the input of VPC generators that exhibit low operation efficiency. It thereby results in a decrease in the entire benefit. The VPP operator benefit significantly decreases when EW is 100 million in all cases except those in which the LDIC is 90%. The benefit of approximately 32 million KRW is reduced when EW is 200 million based on the LDIC of 70%. Such a decrease occurs because diesel generators that incur higher fuel costs are inputted. Table 4 outlines the VPP operational benefit according to EW and LDIC.

Fig. 6 shows the economic loss rate with respect to EW for different LDIC values. The loss rate is defined as the ratio of economic loss in a percentile of the benefit at EW 0 for a given LDIC. In general, the loss rate increases as EW and LDIC increase. Unlike the case in which EW is 0, this loss occurs because diesel generators that exhibit low operation efficiency are additionally inputted to enable equal operations. However, with the high LDIC value, the loss rate decreases because most diesel generators are used, even when EW 0, thereby incurring a high cost. The total benefit of the VPP operator is the sum of the basic compensation (obliged reduction capacity × basic settlement) and the power reduction compensation (operation benefit). Therefore, the total benefits of VPP operators according to the proposed equality operation including basic compensation (2,560 million KRW) decreased by 0.38% on average and decreased by a maximum of 1.05%. It is thus insignificant. The VPP operator can adjust EW to establish a VPP operation plan in the desired direction. It is worth it for the VPP operator to accept this loss, which minimizes dissatisfaction of participating customers and enables the establishment of a reliable VPP.

6. Conclusion

In this paper, an optimal-operation algorithm was proposed that considers the amount of operation time spent by VPC generators to reduce power consumption. It operates under the constraints of available daily and annual operation times when VPP operators based on local generators perform power transactions in the capacity market. The operational effects were based on the degree of equality in the time used by the VPC generators for power reduction. These effects were analyzed through a comparison by applying the algorithm to the Korean power market.

It was determined that, when a VPP operator pursues a balanced operation with participating generators, IMI can be reduced by increasing EW. When EW values are high, less efficient VPC generators are involved, resulting in profit reductions. Such a decrease occurs because diesel generators that incur high fuel costs are inputted. However, the benefits of VPP operators according to the proposed equality operation including basic compensation (2,560 million KRW) decreased by 0.38% on average and decreased by a maximum of 1.05%. The loss is, therefore, insignificant. In result, it is worth it for the VPP operator to bear this loss in order to minimize customer dissatisfaction with VPC generators and to establish a reliable VPP. Balanced operation results may differ depending on the composition of the VPC generators used. LDIC and the number of LDI can additionally alter the results.

Nomenclature

A_j^{Dev}	Absolute deviation between operation time of generator j and the average operation time of generators
B_{jl}	Slope of block l of the piecewise linear production cost function of generator j
C	Set of generators that can participate in the VPP program
CG	Generator set operated in constant output mode
CNT_j^{TOTAL}	Total operation time of j^{th} VPC generator before planning
CSC_j	Cold start-up cost of generator j
CST_j^{DOT}	Daily maximum operation time available
CST_j^{YOT}	Annual maximum operation time available of the j^{th} VPC generator
D_t	LDIC at time t
DK_j	Shut-down cost of generator j
EW	Equality weight
HSC_j	Hot start-up cost of generator j
ID_j	Number of initial periods during which unit j must be offline
IMI	Imbalance index
IU_j	Number of initial periods during which unit j must be online
$L_{j,t}^{CBL}$	Customer baseline of customer j at time t
$L_{j,t}^{CUS}$	Load of customer j at time t
$L_{j,t}^{R}$	Load reduction of customer j at time t (CBL: load)
LG	Generator set operated in load-following output mode
MDT_j	Minimum down time of generator j
MUT_j	Minimum up time of generator j
NL_j	Number of segments of the piecewise linear production cost function of generator j
N	Total number of generators
$OC_{j,t}$	Operation cost of generator j at time t
OP	Generator operation status: on/off (on: 1, off: 0)
$P_{j,t}$	Power generation of generator j at time t
$P_{j,t}^{CG}$	Power generation of constant type generator j at time t
$P_{j,t}^{LG}$	Power generation of load following type generator j at time t
P_j^{Max}	Maximum power generation capacity of generator j
P_j^{Min}	Minimum power generation capacity of generator j
PR_t^R	Power market settlement price in accordance with time t (kWh / KRW)
S_{jl}	Upper limit of block l of the piecewise linear production cost function of generator j
$SDC_{j,t}$	Shut-down cost of generator j at time t
$SUC_{j,t}$	Start-up cost of generator j at time t
T	VPP operation plan time
$TD_{j,t}$	Time a generator j has been off
UK_j^n	Approximation coefficients of step function
VG	Generator set operated in variable output mode
W^D	Maximum acceptable amount of power reduced of power market
x_j	Operation rate of VPC generator for j (%)
x'	Average operation rate (%)
x_j^+, x_j^-	Linearization parameter
λ	Equality weight
ρ_j	Cooling time constant of generator j

Acknowledgements

This work was supported by the Korea Institute of Energy Technology Evaluation and Planning (KETEP) and the Ministry of Trade, Industry & Energy (MOTIE) of the Republic of Korea (20131010501760).

References

[1] S. You, C. Træholt, B. Poulsen, "Generic Virtual Power Plants: Management of Distributed Energy Resources under Liberalized Electricity Market," *8th*

IET International Conference on Advances in Power System Control, Operation and Management. Hong Kong, China: Institution of Engineering and Technology, Nov. 2009

[2] P. Lombardi, M. Powalko, K. Rudion, "Optimal Operation of a Virtual Power Plant," *IEEE Power & Energy Society General Meeting,* Calgary, Canada, July 2009.

[3] N. Ruiz, I. Cobelo, J. Oyarzabal "A Direct Load Control Model for Virtual Power Plant Management," *IEEE Transactions on Power Systems,* vol. 24, pp. 959-966, May 2009.

[4] M.A Salmani, et al., "Virtual Power Plant: New Solution for Managing Distributed Generations in Decentralized Power Systems," *Management and Service Science, 2010 International Conference*, pp. 1-6, 2010.

[5] D. Hropko, J. Ivanecký; J. Turček "Optimal Dispatch of Renewable Energy Sources Included in Virtual Power Plant Using Accelerated Particle Swarm Optimization," *ELEKTRO 2012*, pp. 196-200, Oct. 2012.

[6] M. Peikherfeh, M. H. Seifi, M. K. Sheikh-El-Eslami, "Optimal Decision Making for Virtual Power Plant Operation," *IPEC 2010 Conference Proceedings,* pp. 625-629, Oct. 2010.

[7] M. Peikherfeh, M. H. Seifi, M. K. Sheikh-El-Eslami, "Decision Making of a Virtual Power Plant under Uncertainties for bidding in a Day-ahead Market using Point Estimate Method," *International Journal of Electrical Power & Energy Systems,* vol. 44, pp. 88-98, Jan. 2013.

[8] M. A. Tajeddini, A. Rahimi-Kian, A. Soroudi, "Risk Averse Optimal Operation of a Virtual Power Plant Using Two-stage Stochastic Programming," *Energy,* vol. 73, pp. 958-967, Aug. 2014.

[9] S. R. Dabbagh, M. K. Sheikh-El-Eslami, "Risk-based Profit Allocation to DERs Integrated with a Virtual Power Plant Using Cooperative Game Theory," *Electric Power Systems Research,* vol. 121, pp. 368-378, April 2015.

[10] Y. Wang, Xin Ai, Z. Tan, Lei Yan, "Interactive Dispatch Modes and Bidding Strategy of Multiple Virtual Power Plants Based on Demand Response and Game Theory," *IEEE Transactions on Smart Grid,* vol. 7, pp. 510-519, Jan. 2016.

[11] H. Taheri, A. Rahimi-Kian, H. Ghasemi, B. Alizadeh, "Optimal Operation of a Virtual Power Plant with Risk Management," *Innovative Smart Grid Technologies* (*ISGT*), *2012 IEEE PES*, pp. 16-20, Jan. 2012.

[12] P. B. Andersen, B. Poulsen, M. Decker, C. Træholt, J. Ostergaard, "Evaluation of a Generic Virtual Power Plant Framework Using Service Oriented Architecture," *2nd IEEE International Conference on Power and Energy,* 2008.

[13] Srdan Vukmirovic, Aleksandar Erdeljan, Filip Kulic, Slobodan Lukovic, "Software Architecture for Smart Metering Systems with Virtual Power Plant," *15th IEEE Mediterranean Electrotechnical Conference,* 2010.

[14] A. Moshari, A. Ebrahimi. M. Fotuhi-Firuzabad, "Short-Term Impacts of DR Programs on Reliability of Wind Integrated Power Systems Considering Demand-Side Uncertainties," *IEEE Transactions on Power Systems,* vol. 31, pp. 2481-2490, May 2016.

[15] Association of Edison Illuminating Companies, "Demand Response Measurement & Verification," March 2009.

[16] Zheng Hu, Jin-ho Kim, Jianhui Wang, John Byrne, "Review of Dynamic Pricing Programs in the U.S. and Europe: Status Quo and Policy Recommendations," *Renewable and Sustainable Energy Reviews,* vol. 42, pp. 743-751, Feb. 2015.

[17] Korea Power Exchange(KPX), "Electricity Market Operation Rules," 2015.

[18] A. J. Wood and B. F. Wollenberg, *Power Generation, Operation, and Control, 2nd Ed.,* New York: Wiley, 1996.

[19] R. E. Bixby, M. Fenelon, Z. Gu, E. Rothberg, and R. Wunderling, "MIP: Theory and Practice Closing the Gap," *System Modeling and Optimization: Methods, Theory and Applications,* M. J. D. Powell and S. Scholtes, Eds. Norwell, MA: Kluwer, 2000, pp. 19-50.

[20] R. E. Bixby, M. Fenelon, Z. Gu, E. Rothberg, and R. Wunderling, "Optimal Response of a Thermal Unit to an Electricity Spot Market," *IEEE Transactions on Power Systems,* vol. 15, pp. 1098-1104, Aug. 2000.

[21] M. Carrion, J. M. Arroyo, "A Computationally Efficient Mixed-Integer Linear Formulation for the Thermal Unit Commitment Problem," *IEEE Transactions on Power Systems*, vol. 21, pp. 1371-1378, Aug. 2006.

[22] M. P. Nowak and W. Römisch, "Stochastic Lagrangian Relaxation Applied to Power Scheduling in a Hydro-thermal System under Uncertainty," *Ann. Oper. Res.,* vol. 100, pp. 251-272, 2000.

[23] F. Mohamed, "Microgrid modelling and online management," Ph.D. dissertation, Helsinki University of Technology, Helsinki, Finland, 2008.

Sung-Won Park He received the B.S. and M.S. degrees in Information and Communication Engineering and Department of Electrical Engineering from Gachon University, Korea, in 2011 and 2013, respectively. He is currently working toward the Ph.D. in Department of Electrical Engineering at Gachon University, Korea. His research interests include

smart grid, prosumer, renewable energy forecasting, optimal operation and planning of power system and electricity market analysis.

Yong-Gi Park He received B.S B.S., M.S., and Ph.D. degrees from Konkuk University, Korea, in 2005, 2009, and 2014 respectively. For 2005-2007, he worked in Samsung Electronics Corporation. For 2016-2017, he was with Research Center for Innovative Electricity Market Technology, Konkuk University, Korea. Currently, he is an assistant professor with Department of Electrical and Electronic engineering, Youngsan University, Korea. His research interest includes optimal operation and planning of power system, and electricity market analysis.

Sung-Yong Son He received his B.S. and M.S. from the Korea Advanced Institute of Science and Technology (KAIST), Korea, in 1999 and 1992, respectively, and his Ph.D. in mechanical engineering from the University of Michigan, Ann Arbor, in 2000. From 2000 to 2005, he worked at 4DHomeNet and Icross-technology. He is an associate professor in the Department of Electrical Engineering, Gachon University, Korea. His main research interests include smart grids and smart homes.