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Energy Storage System Owner as a New Player in an Electricity Structure

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Abstract

Daily load demand causes different marginal cost at each hour due to different operation generation units. During peak load period, expensive generation units are determined to be turned on to provide sufficient electricity supply and sufficient spinning reserve. During light load period, generation units could not be unloaded due to their minimum up/down time, startup time and startup cost, causing uneconomic operation of the generating capacities. This excess capacity during light load period can be stored in the energy storage system (ESS) and the power can be released to supply the peak load demand hours to avoid turning on the next expensive unit which resulted in higher marginal cost. Performing as virtual power plant (VPP), ESS owners can seek for market opportunities to enter electric supply industry. This paper aims for proposing an optimal operation of VPP with charging/discharging ESS plan when marginal cost identifies real-time pricing (RTP) at each hour to be used as buying/selling price to VPP. Under strategically charging/discharging scheme, both parties, i.e., utility, and VPP, can achieve benefits in terms of better economic operation, lower system generation cost, increase operational income, while environmental impact is considered. The proposed method is tested on a ten-unit system under a centralized power market structure. Numerical results show that appropriate charging/discharging strategy could provide lower total production cost and offer opportunities for ESS owners as VPPs to obtain arbitrage marginal cost.

Keywords: *energy storage system; generation scheduling; production cost; virtual power plant, environment*

1. Introduction

Hourly load demand varies depending on load profile of each sector, such as industry, commercial and residential, which is determined by economic parameters, quality of life and consumer behaviours. During the night, the load demand is significantly lower compared to daytime demand, particularly before noon, in the afternoon, and in the evening. The low load demand that happens during the entire day is defined as base load. Appropriate generation scheduling (GS) Hobbs et al. (2001), Nirukkanaporn & Petcharaks (2019a, 2019b), Ongsakul & Dieu (2013), Ongsakul & Petcharaks (2004), Petcharaks (2006, 2008, 2014, 2015), Petcharaks & Ongsakul (2007), Sheble & Fah (1994), Thongheet, Chimhat & Petcharaks (2010), Tseng et al. (1999), Wood & Wollenberg (2013), is needed to provide sufficient electricity supply and sufficient spinning reserve. Generation units will be determined to be turned on/off appropriately to achieve the objective of minimizing the total production cost while satisfying all important operational constraints such as power balance constraint, spinning reserve constraint, minimum up and down time constraints, maximum and minimum limit, etc. During peak load period, most of generation units are turned on to supply sufficient power and spinning reserve. Thus, the marginal unit in this hour is identified by the expensive generation unit, resulting high marginal cost of the system during peak load period. Peaking generators are units that supply the peak load at a high cost, while intermittent generation units with medium costs supply intermittent load. In the night, load decreases slowly in each hour entering base load periods, peak load units and intermittent units are scheduled to be turned off. However, system operator (SO), who controls and operates the generators in the system, may not be able to turn off some generation units due to generator's minimum up time constraints or startup time constraints, and worthy startup cost. Therefore, there are excess reserves during these hours which could be benefit to all parties in electric supply industry (ESI) if appropriate algorithms are implemented to use this excess power to cut peak demand during peak load time. In the event that electricity customers own an energy storage system (ESS), they can act as both suppliers and consumers, a role referred to as 'prosumer'. During base or light load period, they can charge their ESS as consumers by buying power at low RTP at those hours and store power to supply power to the system during peak load hours as suppliers by selling power at high RTP at those hours. Supplying power from the ESS discharging during peak load hours reduces peak load demand, leading to the deactivation of marginal generation units and affecting total costs. This provides opportunity for ESS owners in arbitrage from net income gained by selling power during peak load hours (high RTP) and buying excess energy during light load hours (low RTP). In addition, appropriate charging/discharging strategy may plan to keep marginal unit running during some hours if it is worth to charge energy in those hours and supply power back to the system during the next peak load periods.

ESS owners could gain potential revenue as a new players (vendors) or virtual power plant (VPP) in ESI if there is a significant difference between light load and peak load (In a centralized system, ESS does not need to decide which hours to buy/sell power). This situation can also decrease total production cost. Thus, ESS owners could emerge in electricity structure as new players in form of VPPs who could both supply and consume power. This could provide benefits for both stakeholders: utility obtains lower production cost, and ESS owners obtain profit. Therefore, if new players are allowed to emerge in a centralize electricity structure, it could provide benefit for both participants. Real time pricing (RTP) which is the marginal cost at each hour is the key factor. ESS owners can earn profit from the difference of RTPs at different hours. RTP is used in electricity market. RTP is also applied for Demand response in IEEE 30 bus system (Chayakulkheeree et al., 2019). Nodal price has been used in multiple microgrids (Velasquez et al., 2019).

In Thailand, most of generation power is supplied by EGAT (Electricity Generating Authority Thailand), IPP (Independent power producer) and SPP (Small power producer) (Tunpaiboon, 2016). Meanwhile, the renewable power, especially on solar power, and demand response scheme are strongly encouraged. The Thai power system is shifting to more competitive nature and requires smarter utilization of high diversity resources. Figure 1 shows the Thai power system with its upcoming possible structure. Therefore, the energy storage system (ESS) will play an important role in both utility and end user sides. If ESS owners emerge in this structure to offer power in some hours and to consume power in other hours, it would benefit to both stakeholders if they could reduce electric demand and production cost consequently.

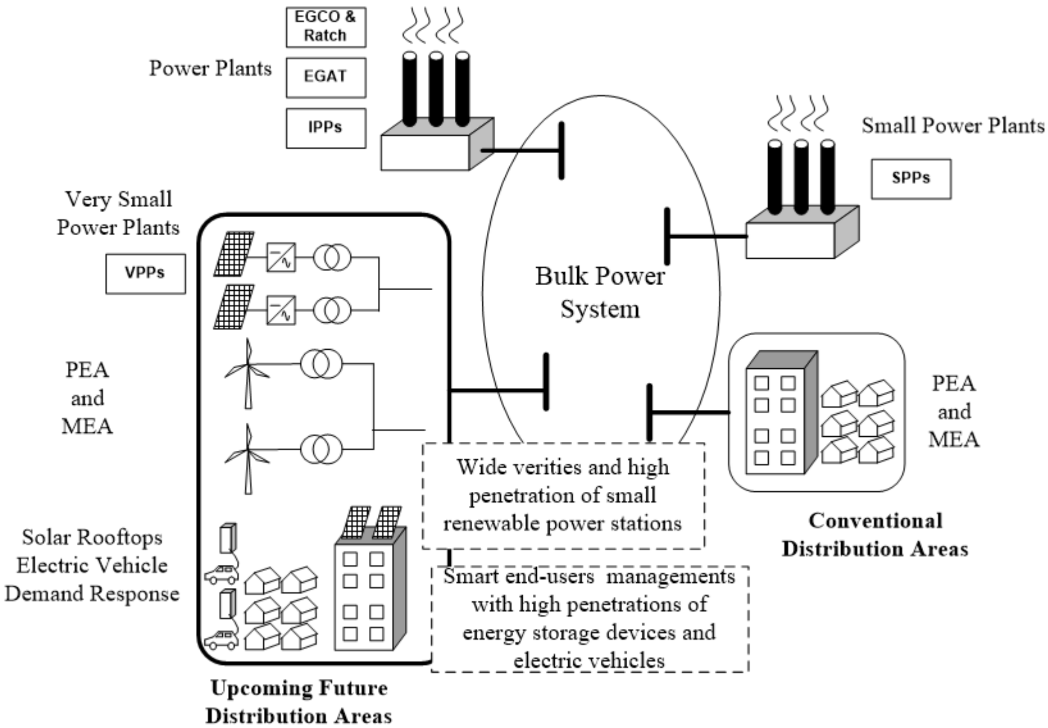

Figure 1 Upcoming possible structure of electricity supply industry structure in Thailand

The generation scheduling problem (GSP) has been a continuous area of interest in electrical power system continuously since 1966 in order to obtain the cost saving and better environment and better solution for decision making in generating unit operation (Hobbs et al., 2001; Nirukkanaporn & Petcharaks, 2019a, 2019b; Ongsakul & Dieu, 2013; Ongsakul & Petcharaks, 2004; Petcharaks, 2006, 2008, 2014, 2015; Petcharaks & Ongsakul, 2007; Sheble & Fahd, 1994; Thongheet et al., 2010; Tseng et al., 1999; Wood & Wollenberg, 1996). Whereas smart grid is now the target of utilities around the world to supply their growing electricity demand with sustainable supply and advance technology and to preserve environment. These require renewable sources, smart communication and smart control and operation. Renewable energy sources (RES) are sustainable and located in many places known as distributed generator (DG). Whereas ESS could be used to enhance electric power system with RES. ESS draws interesting from researchers and utilities to solve power fluctuation from RES. ESS could be battery bank (BB) or pumped storage generators or other storage system that consumes power in some hours and thereafter supplies power in other hours. ESS owners could emerge in electric supply industry as virtual power plant (VPP) as they can supply power in some hours under some limitations. Various research methods have been developed continuously (Shareef & Rao, 2022; Petcharaks, 2006, 2014; Sheble & Fahd, 1994; Wood & Wollenberg, 1966). Recently, modified dynamic programming (MDP) has been proposed in 2019 (Nirukkanaporn & Petcharaks, 2019a, 2019b). Mixed integer programming (MIP) has been proposed in 2010 (Thongheet et al., 2010) to solve GSP in which some variables are real number, but some variables are required to be integer. However, the algorithm and mathematic formulation is very important and key factors of implementation in every method.

However, charging energy means consuming electricity, which could result in higher load demand. This could lead to insufficient spinning reserve at that hour, which may cause to turn on a new marginal unit with higher cost. In addition, charging energy could not be used 100% due to ESS efficiency. Therefore, the overall objective of GSP should be minimizing total production cost subject to ESS charging/ discharging constraints and other important constraints. This needs complicated algorithms to search for optimum solution. Effective charging/discharging strategy optimizes charging/discharging profile for day ahead planning to obtain minimum total production cost which provides benefit for all participants (Amarendra, Srinivas & Rao, 2022). This arbitrage income results from load demand time shift, spinning reserve, and new generation unit deferral.

A trial structure with new player, ESS owners in a centralized electric structure was examined. Algorithms of charging/discharging strategy are mathematically formulated. MILP method is used to search for optimum solution while satisfying charging/discharging constraints and other important constraints. The objective of this paper is to minimize total production cost including ESS while satisfying charging/discharging constraints and other important constraints. It is tested on a ten-unit system under different scenarios to examine the benefit from various ESS capacities.

2. Problem Formulation

The objective function is to minimize the total production cost from generation units including cost from ESS.

$$F(P_i^t, U_i^t) = \sum_{t=1}^{NT} \sum_{i=1}^{NG} [F_i(P_i^t) + ST_i^t(1 - U_i^{t-1})]U_i^t + \sum_{t=1}^{NT} \sum_{es=1}^{NES} b_{es}[P_{es,d}^t U_{es,d}^t + P_{es,c}^t U_{es,c}^t] \quad (1)$$

Subject to:

(1) power balance constraint

$$P_{load}^t - \sum_{i=1}^{NG} P_i^t U_i^t - \sum_{es=1}^{NES} P_{es,d}^t U_{es,d}^t + \sum_{es=1}^{NES} P_{es,c}^t U_{es,c}^t = 0, t = 1, \dots, NT \quad (2)$$

(2) spinning reserve constraint

$$P_{load}^t + R^t + \sum_{es=1}^{NES} P_{es,c}^t U_{es,c}^t - \sum_{i=1}^{NG} P_i^{max} U_i^t - \sum_{es=1}^{NES} P_{es,d}^t U_{es,d}^t \le 0 \quad (3)$$

(3) minimum up/down time constraint

$$U_i^t = \begin{cases} 1, & if\ T_{i,on}^{t-1} \le T_{i,up}, \\ 0, & if\ T_{i,off}^{t-1} < T_{i,down}, \end{cases} \quad (4)$$

(4) startup cost constraint

$$ST_i^t = \begin{cases} HST_i, & if\ T_{i,off} \le T_{i,cold} + T_{i,down} \\ CST_i, & if\ T_{i,off} > T_{i,cold} + T_{i,down} \end{cases} \quad (5)$$

Additional variables are added to the hour that units are scheduled to startup and shutdown, z_i^t and y_i^t respestively.

Auxiliary variables w_i^t and q_i^t, for auxiliary constraints

$$w_i^t = U_i^t - U_i^{t-1}, t = 2, \dots, 24 \quad (6)$$

$$w_i^1 = U_i^1 - InitU_i \quad (7)$$

$$w_i^t - z_i^t \le 0 \quad (8)$$

$$q_i^t = U_i^{t-1} - U_i^t, t = 2, \dots, 24 \quad (9)$$

$$q_i^1 = InitU_i - U_i^1 \quad (10)$$

$$q_i^t - y_i^t \le 0 \quad (11)$$

(5) generation limit constraint

$$P_{i,min} U_i^t \le P_i^t \le P_{i,max} U_i^t, i = 1, \dots, NG, \quad (12)$$

$$P_{es,min} U_{es,d}^t \le P_{es}^t \le P_{es,max} U_{es,d}^t, es = 1, \dots NES \quad (13)$$

$$0 \le P_{es,d}^t \le SOC_{es}^{t-1}, es = 1, \dots . NES, \quad (14)$$

SOC_{es}^{t-1}: State of charged energy of ESS unit *es* at hour *t-1*,

$$P_{es,min} U_{es,c}^t \le P_{es,c}^t \le P_{es,max} U_{es,c}^t, es = 1, \dots NES \quad (15)$$

ESS energy at the end of hour *t*,

$$SOC_{es}^t \le SOC_{es}^{t-1} + P_{es,c}^t U_{es,c}^t - \frac{1}{\eta_{es}} P_{es,d}^t U_{es,d}^t \quad (16)$$

$$E_{es,min} \le SOC_{es}^t \le E_{es,max} \quad (17)$$

η_{es}: charge/discharge efficiency

(6) charging/discharging constraint

$$U_{es,d}^t + U_{es,c}^t \le 1, \quad (18)$$

(7) energy balance of battery energy storage constraint

$$\sum_{t=1}^{t_c} P_{es,d}^t \times U_{es,d}^t \leq \eta_{es} \sum_{t=1}^{t_c} P_{es,c}^t \times U_{es,c}^t \, , t = 1, .., T \quad (19)$$

(8) System Operator (SO) Net Cost

$$NC_{SO}=PC_{utility}+ PC_{BFVPP}- PC_{STVPP} \quad (20)$$

where total production cost from thermal power plants owned by utility,

$$PC_{utility} = \sum_{t=1}^{NT} \sum_{i=1}^{NG} [F_1(P_i^t) + ST_i^t(1 - u_i^{t-1})\,] u_i^t \quad (21)$$

total production cost buying from virtual power plant (VPP),

$$PC_{BFVPP}= \sum_{t=1}^{NT} \sum_{es=1}^{NES} P_{es,d}^t \, u_{es,d}^t RTP^t \quad (22)$$

total production cost selling to VPP,

$$PC_{STVPP}= \sum_{t=1}^{NT} \sum_{es=1}^{NES} P_{es,c}^t \, u_{es,c}^t RTP^t \quad (23)$$

(9) VPP profit

$$PF_{VPP}=PC_{BFVPP}- PC_{STVPP} \quad (24)$$

(10) Total CO_2 Emissions

$$EM_{total} = \sum_{t=1}^{NT} \sum_{i=1}^{NG} P_i^t EM_i \quad (25)$$

3. Methodology

3.1 Objective function

The objective function contains decision variables and auxiliary variables both real and integers such as binary variables {0,1}. A systematic procedure is needed to search for the optimal solution. This problem is a mixed integer optimization problem. Thus, MILP is used by estimating quadratic cost fuel function to be an approximately equivalent linear cost function.

The objective function in (1) contains binary variables such as U_i^t, $U_{es,d}^t$, $U_{es,c}^t$, etc. and real continuous variables such as P_i^t, $P_{es,d}^t$, etc. Similarly, problem constraints contain both binary variables and real continuous variables. MILP is used to find the minimum objective function while satisfying all constraints by temporary relaxing the integer and binary decision variables, which are initially set as continuous real numbers in the range of 0-1. Production cost is estimated from quadratic function to linear cost function. Then, the linear programming (LP) method is applied to find a rough solution by minimizing the production cost function with relaxation of integer and binary values subject to all constraints. Next, each relaxed value is determined one by one. The first decision variable to be determined is the one with its value close to 0.5. Given that x_1 is the first decision variable to be considered, beginning with separating a search route into two branches, $x_1 = 0$ and $x_1 = 1$, the variables x_1 are expressed at the first node in branch and bound tree in Figure 2. The relaxing variables x_1 are branched to the integer values of '0' and '1'. In case of feasible solutions, the corresponding objective functions, C1 for x_1=0 and C2 for x_1=1, are calculated and shown in diagram. In case of infeasible solutions, the objective function will be blanked. MILP will select the branch with the lower objective function. Next, MILP will continue to determine the next integer variable in the similar way. MILP determining process is repeated until all integer and binary variables are selected to be either '0' or '1'.

A generator unit status of $U_i^t=1$ means that the generator is running with its production cost including no-load cost, subjected to the generation output constraint within its minimum and maximum limit, providing additional spinning reserve due to the difference between the maximum limit and the actual generation output in that period. Whereas the unit status of $U_i^t=0$ represents the shut-down state of generator, resulting in zero production cost, zero power output and no spinning reserve contribution from this unit. In addition, turning on/off generator must satisfy the minimum up and down time constraint. MILP searches for an optimum solution with simultaneously considering all constraints mentioned above. Thus, MILP is a suitable tool for GSP with/without ESS. Charging/discharging constraints of ESS with specific efficiency, which allows the ESS to behave as either a generator or a load consumer at a given time, are taken into account. The algorithm and mathematical formulation are key mechanism in optimization, thus special concentration is needed.

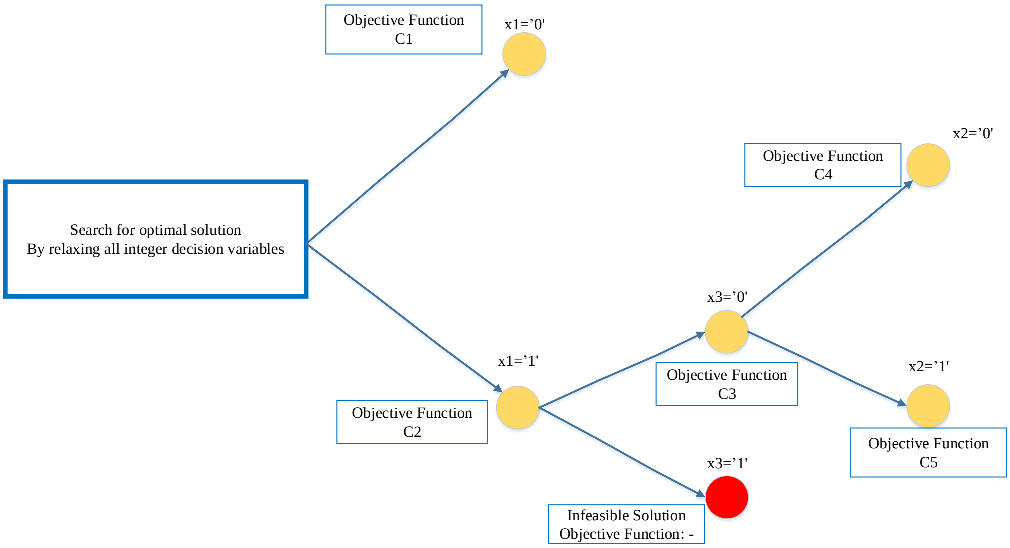

Figure 2 MILP branch and bound tree

The computational steps are as follows:

Step 1 Perform GS without ESS using MILP to obtain RTP^t

Step 2 Perform GS including ESS power step to obtain the optimum number of ESS and charge/discharge periods.

Step 3 Carry out the same process in Step 2 with larger ESS by increasing the ESS power steps until it reaches ESS total capacity.

Step 4 Calculate SO net cost ($/day), VPP profit ($/day) and total CO_2 Emissions (tons/day)

Step 5 Determine the appropriate ESS capacity.

3.2 Test System

The ten-unit system has been widely used since 1999 (Ongsakul & Dieu, 2013; Ongsakul & Petcharaks, 2004; Petcharaks, 2006). The system consists of 10 thermal power plants, as shown in Table A1 in the Appendix. CO_2 emissions from each power plant is shown in Table A2. Various cases are examined as listed in Table 1 in order to analyze the effect of having ESS in the system, considering ESS operating conditions under different operational strategies and various ESS sizes as VPPs. The ESS power step is set to 50 MW with seven steps. Therefore, the ESS total capacity is 350 MW. In case 1, it is assumed that the utility owns 10 power plants with/without ESS and VPP does not exist. The spinning reserve for this scenario is set at 10% of the load demand. In case 2, it is assumed that the utility owns 10 power plants but ESS with the size varying from 300 to 1400 MW, in case 2A-2G, are VPP-owned. The spinning reserve is 10% of the summation of load demand and ESS charging power subtract with ESS discharging power. It is assumed that ESS variable cost is neglected, and efficiency of ESS is 80%.

The operation of ESS owned by utility (case 1B) is based on the assumption that utility attempts to minimize the cost of charging ESS, i.e. charging ESS during the period that utility has excess supply; whereas the operation of VPP-owned ESS (case 2) assumes that VPP is seeking for opportunities to gain margin from the price difference during the day, i.e. ESS is charged during the period in which the electricity price under centralized generation scheduling with the objective of cost minimization.

4. Numerical results and discussions

Numerical results are shown in Table 2. The total production cost without ESS in case 1A, 565,827.69 $, rBESSeflects the effectiveness of the proposed method compared to those of various methods ranging 563,977 -565,825 $ shown in Ongsakul & Petcharaks (2004).

ESS owners who can buy or sell power to system are treated as virtual power plants (VPP). Production cost is the total fuel cost from thermal generation units. The marginal cost of each hour is determined by the incremental cost of marginal units at that hour which is defined as the Real-time price (RTP) at each hour. The financial amount of buying power from VPP is the amount that utility buys power from VPP calculated from power supplied by VPP multiplying with RTP at that hour. The financial amount of selling to VPP is the amount that utility sells power to VPP calculated from power charging to ESS multiplying by RTP. Net cost to the system operator (SO) is the total system cost calculated from production cost plus cost of buying power from VPP minus the utility's income from selling power to VPP. The average cost is calculated from net cost to SO dividing by total daily load demand of 27,100 MWh. The VPP can earn profit from selling and buying power to utility. It is calculated from the difference of financial amounts that utility buys and sells power with VPP.

Table 1 The ten-unit system with various cases

case		scenario description	spinning reserve
case 1	A	10-unit system without ESS	10% of P_{load}
	B	10-unit system with 200MW (50 MW 4 set) ESS, utility-owned	
case 2	A	10-unit system with 300MW (50 MW 6 set) ESS, VPP-owned	10% of $(P_{load} + \sum_{es=1}^{NES} P_{es,c}^{t} - \sum_{es=1}^{NES} P_{es,d}^{t})$
	B	10-unit system with 500MW (100 MW 5 set) ESS, VPP-owned	
	C	10-unit system with 750MW (150 MW 5 set) ESS, VPP-owned	
	D	10-unit system with 1000MW (200 MW 5 set) ESS, VPP-owned	
	E	10-unit system with 1000MW (250 MW 4 set) ESS, VPP-owned	
	F	10-unit system with 1200MW (300 MW 4 set) ESS, VPP-owned	
	G	10-unit system with 1400MW (350 MW 4 set) ESS, VPP-owned	

Table 2 Numerical results

Scenario	SO			VPP	
	Production Cost ($)	**Net Cost ($)**	**Average Cost ($/MWh)**	**Profit ($)**	**Emissions (tons/day)**
Case 1: Introducing utility-owned ESS					
1A: no ESS	565,827.69	565,827.69	20.88	-	21,907.14
1B: 200 MW ESS (50 MW 4 set)	565,573.43	565,573.43	20.87	-	21,999.84
Case 2: Introducing VPP-owned ESS					
2A: 300 MW ESS (50MW 6 set)	559,490.91	559,716.38	20.654	225.48	22,111.61
2B: 500 MW ESS (100MW 5 set)	556,415.03	556,315.53	20.528	-99.49	22,299.22
2C: 750 MW ESS (150 MW 5 set)	554,881.14	555,206.02	20.487	324.88	22,370.80
2D: 1000 MW ESS (200 MW 5 set)	553,594.41	554,378.29	20.457	783.88	22,450.79
2E: 1000 MW ESS (250 MW 4 set)	553,281.71	554,322.55	20.455	1,040.84	22,493.84
2F: 1200 MW ESS (300 MW 4 set)	553,215.53	554,124.13	20.447	908.60	22,502.06
2G: 1400 MW ESS (350 MW 4 set)	553,219.10	554,127.81	20.448	908.71	22,502.06

Case 1 GS with introducing utility-owned ESS.

In Case 1A, the 10-unit system without ESS, the total production cost is $565,827.69 and the average cost is 20.88 $/MWh. Introducing four sets of 50-MW ESS into the 10-unit system as utility's property in case 1B, while maintaining spinning reserve of 10% of load demand, results in lowering the total production cost to $565,573.43, or saving $254.26 or 0.045%, and lowering the average electricity cost to 20.87 $/MWh, or saving 0.01 $/MWh, equating 0.048%. However, the gas emissions of case 1B is 92.70 tons/day or 0.423% higher than the emissions of case 1A, since the power used in charging ESS is obtained from generation no. 2, which is coal power plant with the highest emissions of 920 kg/MWh.

Case 2 GS with emerging of ESS as VPP

Different sizes of ESS are introduced into the test system, varying from 300 to 1400 MW, operating as VPP. VPP is a new player in electricity supply industry structure and acts as a vender searching for profit from varying RTP resulting from different marginal cost in different hours as shown in Figure 3. The spinning reserve is still maintained at 10% of the summation of load demand and ESS charging power subtracted by ESS discharging power. The introduction of VPP-owned ESS in most cases can provide benefits to both stakeholders, i.e., utility obtains lower production cost and VPP obtains profit as shown in Table 2. Numerical results reveal that the optimize algorithms with objective of total production cost minimization, considers charging/discharging ESS power to obtain the lowest cost, it does not consider ESS profit/loss. In case 2B, using ESS five sets of 100 MW, the GSP solution produces loss to ESS. Therefore, compensation to ESS should be determined to stimulate the emerging of ESS as VPP in Electric Supply Industry. However, gas emissions are increasing when larger capacity of ESS is used in the system because power charging to ESS is supplied from coal power plant with highest emissions rate.

Based on the test system, the optimal size of ESS is four sets of 300 MW in case 2F, providing the lowest average cost, whereas VPP could gain maximum profit 1,040.84 $/day, in case 2E using four sets of 250 MW in operation. The RTP, as shown in Figure 3, depends on the operating generation units. RTP is determined by the marginal cost at that hour.

ESS is charged during hour H1-H8, H16-H18 and discharged at hour H9-H14, H20-H23. The decision making was made by assumption of 80% efficiency of ESS under spinning reserve constraint. Considering the spinning reserve from SO perspective, during the ESS charging, it may cause SO to start more generation units leading to higher system marginal cost. On the other hand, during the ESS discharging state, spinning reserve of 10% is based on the SO's load minus ESS discharged power, which may cause shutting down some generation units or avoiding starting more expensive generation units leading to lower SO's total production cost. The power supplied from scheduling thermal power plants at each hour, power charging/discharging from ESS (power trade with VPP), and RTP are shown in Table 3.

Figure 4 shows the system load demand and supplies in the emerging of VPP for the optimal case 2F. System load demand is supplied by SO's thermal units, and VPP supplies during ESS discharging period. On top of the system load, the VPP power demand is added to the system load demand during ESS charging hours.

Figure 5 presents the charging/ discharging strategy based on RTP. VPP can seek for opportunity to gain highest benefit from saving ESS charging cost during low RTP and gaining higher income by selling power to SO at high RTP, while SO can still gain benefit of avoiding turning on more expensive generating unit to support increasing demand, although buying power from VPP at high RTP. VPP could make profit as high as 1,040.84 $/day in case 2E.

Power supplying from each thermal power plant obtained from economic dispatch operation is shown in Table 4.

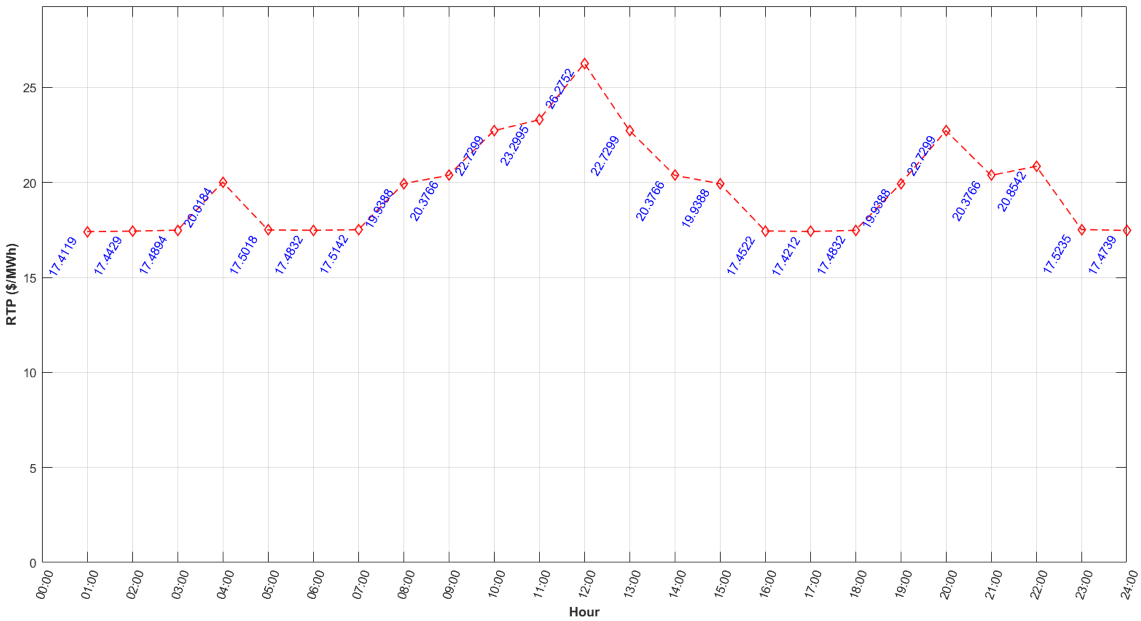

Figure 3 RTP at different hours for the ten-unit system

Table 3 Generation scheduling for the optimal case 2F

Hour	Load Demand (MW) [Total system demand] [1]	ESS as load demand (Charging state) (MW) VPP buying (ESS charging) [2]	ESS as suppliers (Discharging state) (MW) VPP selling (ESS discharging) [3]	Total Power from generators (MW) [SO's load] [4] =[1]+[2]-[3]	RTP ($/MWh)
1	700	274.55	-	974.55	17.412
2	750	202.05	-	952.05	17.443
3	850	124.55	-	974.55	17.489
4	950	24.55	-	974.55	20.018
5	1000	92.73	-	1092.73	17.502
6	1100	110.91	-	1210.91	17.483
7	1150	60.91	-	1210.91	17.514
8	1200	10.91	-	1210.91	19.939
9	1300	-	16.36	1283.64	20.377
10	1400	-	116.36	1283.64	22.730
11	1450	-	166.36	1283.64	23.300
12	1500	-	216.36	1283.64	26.275
13	1400	-	116.36	1283.64	22.730
14	1300	-	89.09	1210.91	20.377
15	1200	-	-	1200	19.939
16	1050	145.00	-	1195	17.452
17	1000	207.73	-	1207.73	17.421
18	1100	95.00	-	1195.00	17.483
19	1200	-	-	1200	19.939
20	1400	-	189.09	1210.91	22.730
21	1300	-	89.09	1210.91	20.377
22	1100	-	7.27	1092.73	20.854
23	900	-	72.73	827.27	17.524
24	800	-	-	800	17.474

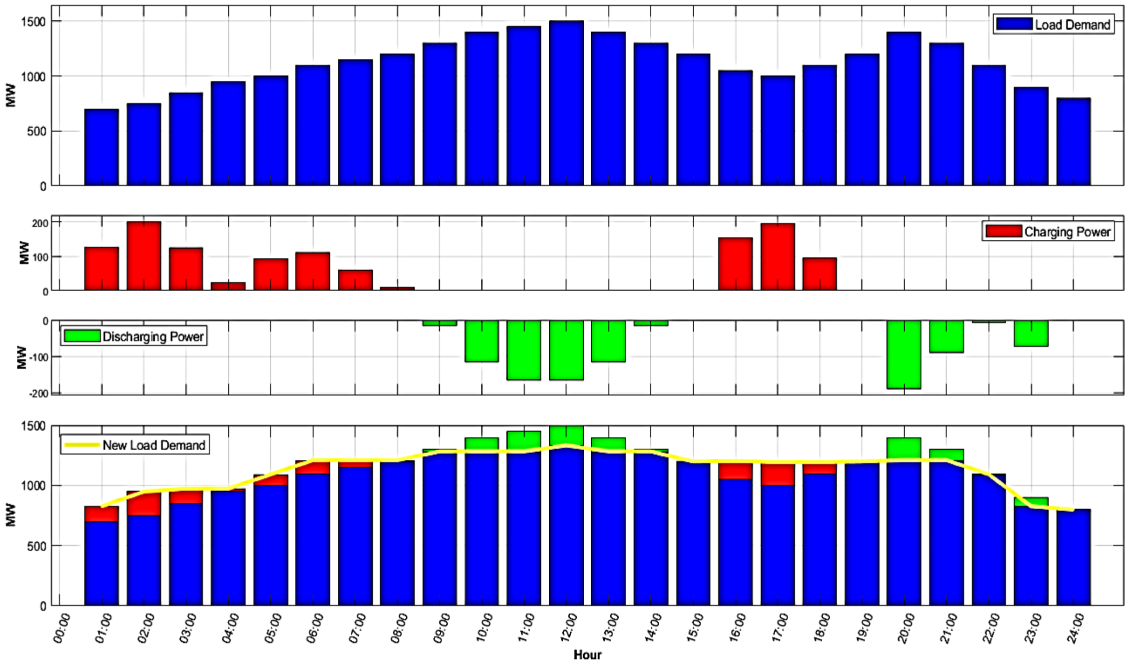

Figure 4 Charging/discharging periods depending on load demand for Case 2F, VPP using ESS 1200 MW (four sets of 300 MW).

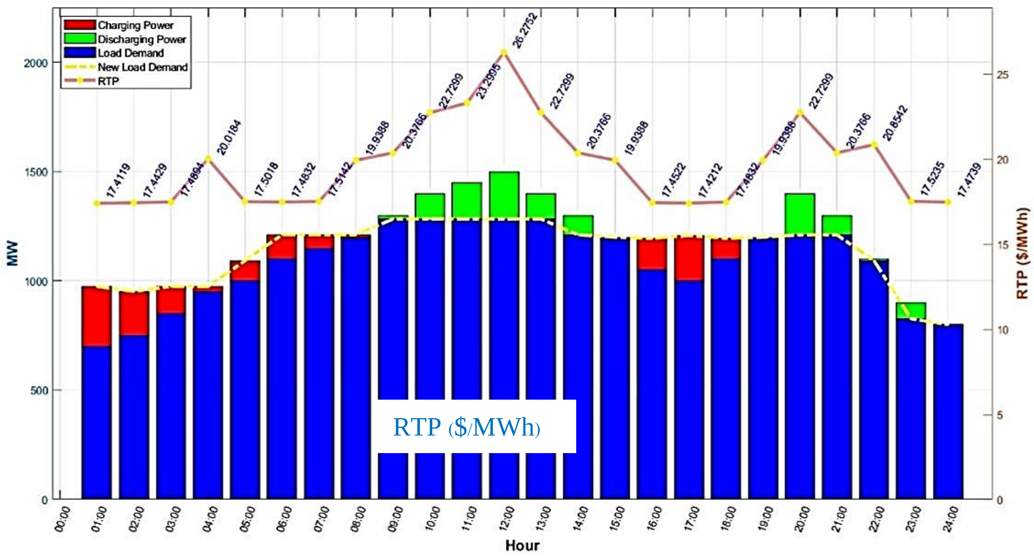

Figure 5 Charging/discharging periods strategy based on RTP for the optimal case (case 2F)

Table 4 Power supplying from thermal power plants for optimal case (case 2F)

Hour	Power (MW)										
	G1	**G2**	**G3**	**G4**	**G5**	**G6**	**G7**	**G8**	**G9**	**G10**	**Total**
H1	455	455	0	0	64.55	0	0	0	0	0	974.55
H2	455	455	0	0	42.05	0	0	0	0	0	952.05
H3	455	455	0	0	64.55	0	0	0	0	0	974.55
H4	455	455	0	0	64.55	0	0	0	0	0	974.55
H5	455	455	0	130	52.73	0	0	0	0	0	1092.73
H6	455	455	130	130	40.91	0	0	0	0	0	1210.91
H7	455	455	130	130	40.91	0	0	0	0	0	1210.91
H8	455	455	130	130	40.91	0	0	0	0	0	1210.91
H9	455	455	130	130	93.64	20	0	0	0	0	1283.64
H10	455	455	130	130	93.64	20	0	0	0	0	1283.64
H11	455	455	130	130	93.64	20	0	0	0	0	1283.64
H12	455	455	130	130	93.64	20	0	10	0	0	1283.64
H13	455	455	130	130	93.64	20	0	0	0	0	1283.64
H14	455	455	130	130	40.91	0	0	0	0	0	1210.91
H15	455	455	130	130	30.00	0	0	0	0	0	1200
H16	455	455	130	130	25.00	0	0	0	0	0	1195
H17	455	455	130	130	37.73	0	0	0	0	0	1207.73
H18	455	455	130	130	25.00	0	0	0	0	0	1195.00
H19	455	455	130	130	30.00	0	0	0	0	0	1200
H20	455	455	130	130	40.91	0	0	0	0	0	1210.91
H21	455	455	130	130	40.91	0	0	0	0	0	1210.91
H22	455	455	0	130	52.73	0	0	0	0	0	1092.73
H23	455	372.27	0	0	0	0	0	0	0	0	827.27
H24	455	345	0	0	0	0	0	0	0	0	800

This paper assumes that VPP owns energy storage system, ESS which could be battery or pumped storage power plants. The pumped hydro energy storage (PHES) could be used for utility-scale electricity storage (Rehman, Al-Hadhrami & Alam, 2015) .Thus, ESS could be either battery energy storage system (BESS) or pumped hydro energy system (PHES). The capacity of BESS in an investigated grid covered by the VPP could be up to 0.5-1.0 MW (Sikorski et al., 2019; Sikorski et al., 2020). With the recent development of the ESS technology, the capacity of ESS is larger. In addition, the size of VPP as an aggregator collecting power capacity from small ESS should be large enough to act as a virtual generator. In this paper, ESS capacity 50 –350 MW are used to investigate the impact of the VPP capacity penetration to system.

However, using ESS could cause higher emissions since charging power is supplied by base load units which are coal power plants in the test system. For the power system with nuclear power plants as base load units, emissions will be lower which is better for environments. In case the power system has renewable energy resources such as solar or wind power generators included in generation units, these renewable resources would cause volatility in power supply, which could result in fluctuating marginal cost and affect generation scheduling. ESS may be more beneficial depending on charging/discharging strategy which should be further studied. Furthermore, compensation to ESS should be considered to ensure non-negative profit to stimulate ESS as VPP since they could provide benefits such as total cost reduction, generator deferral, etc.

5. Conclusion

Varying load demand could cause excessive power during light load periods and supply power at a high marginal price during peak load periods. Thus, charging/discharging strategy could gain benefit by using power with lower marginal cost to be used during peak load hours. Numerical results show that the optimized algorithms could provide lower total production cost. Effective charging/ discharging strategy could gain benefits for both stakeholders. This provides an opportunity for VPPs as ESS owners to emerge in the electricity structure as a new player/vender. In centralized generation scheduling, VPP-owned ESS could be new player who can provide social benefit to both stakeholders. However, compensation to stimulate the emergence of ESS as VPP should be considered to ensure non-negative profit. In addition, using ESS may cause higher emissions since charging power during light load period may be supplied by coal power plants, thus environmental effect should be considered in policy planning.

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Nomenclature

a_i	:	no load cost of unit *i*;
b_i	:	variable cost of unit *i*; (\$/MWh)
b_{es}	:	variable cost of ESS unit es; (\$/MWh)
c_i	:	parameter in cost function of unit *i*;
CST_i	:	cold startup cost of unit *i* (\$);
$E_{es,min}$	:	minimum storage power of energy storage system unit *es* (MWh);
$E_{es,max}$	:	maximum storage power of energy storage system unit *es* (MWh);
EM_i	:	CO_2 Emissions from thermal power plant unit *i* (kg/MWh);
EM_{total}	:	total CO_2 Emissions from thermal power plant per day (tons/day);
$F_i(P_i^t)$	:	generator fuel cost function in a quadratic form, $F_i(P_i^t) = a_i + b_i P_i^t + c_i (P_i^t)^2$ (\$/h),
HST_i	:	hot startup cost of unit *i* (\$);
NES	:	total number of energy storage;
NC_{SO}	:	system Operator (SO) net cost (\$);
NT	:	total number of hours;
NG	:	total number of thermal generator units;
$P_{i,min}$	:	minimum real power generation of thermal unit *i* (MW);
$P_{i,max}$	:	maximum real power generation of thermal unit *i* (MW);
P_i^t	:	generation output power of thermal unit *i* at hour *t* (MW);
P_{load}^t	:	load demand at hour *t* (MW);
$P_{es,c}^t$	:	charging power consumed by energy storage system unit *es* at hour *t* (MWh);
$P_{es,d}^t$	:	discharging power supplied by energy storage system unit *es* at hour *t* (MWh);
$P_{es,min}$	:	minimum output power of energy storage system unit *es*, (MW);
$P_{es,max}$	:	maximum output power of energy storage system unit *es*, (MW);
$PC_{utility}$	:	total production cost from thermal power plants (\$/day);
PC_{BFVPP}	:	total production cost buying from VPP (\$/day);
PC_{STVPP}	:	total production cost selling to VPP (\$/day);
R^t	:	spinning reserve at hour *t* (MW);
RTP^t	:	real-time price at hour *t* (\$/MWh);
SOC_{es}^t	:	state of charged energy of energy storage system unit *es* at hour *t* (MWh);
ST_i^t	:	startup cost of unit *i* at hour *t* (\$);
$T_{i,cold}$	:	cold start hour unit *i* (h);
$T_{i,down}$	:	minimum down time of thermal unit *i* (h);
$T_{i,off}^{t-1}$	:	continuously off time of unit *i* (h);
$T_{i,on}^{t-1}$	:	continuously on time of unit *i* (h);
$T_{i,up}$	:	minimum up time of thermal unit *i* (h);
U_i^t	:	status of thermal unit *i* at hour *t* (on = 1, off = 0);
$U_{es,c}^t$	:	status of energy storage system unit *es*, in charging state at hour *t* (on = 1, off = 0);
$U_{es,d}^t$	:	status of energy storage system unit *es*, in discharging state at hour *t* (on = 1, off = 0);
η_{es}	:	charge/discharge efficiency of energy storage system unit *es*;
z_i^t	:	startup status of unit *i* at hour *t*,
y_i^t	:	shut down status of unit *i* at hour *t*,

Appendix

Table A1 Unit data with quadratic cost function for the 10 unit system

	Unit 1	Unit 2	Unit 3	Unit 4	Unit5
P_{max} (MW)	455	455	130	130	162
P_{min} (MW)	150	150	20	20	25
a ($/h)	1000	970	700	680	450
b ($/MWh)	16.19	17.26	16.60	16.50	19.70
c ($/MW^2-h)	0.00048	0.00031	0.002	0.00211	0.00398
min up (h)	8	8	5	5	6
min down (h)	8	8	5	5	6
hot start cost ($)	4500	5000	550	560	90
cold start cost ($)	9000	10000	1100	1120	1800
cold start hours(h)	5	5	4	4	4
initial status (h)	8	8	-5	-5	-6
FLAC ($/MWh)	18.576	19.533	22.245	22.005	23.122

	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
P_{max} (MW)	80	85	55	55	55
P_{min} (MW)	20	25	10	10	10
a ($/h)	370	480	660	665	670
b ($/MWh)	22.26	27.74	25.92	27.27	27.79
c ($/MW^2-h)	0.00712	0.00079	0.00413	0.00222	0.00173
min up (h)	3	3	1	1	1
min down (h)	3	3	1	1	1
hot start cost ($)	170	260	30	30	30
cold start cost ($)	340	520	60	60	60
cold start hours(h)	2	2	0	0	0
initial status (h)	-3	-3	-1	-1	-1
FLAC ($/MWh)	27.455	34.059	38.147	40.582	40.067

Table A2 CO_2 emissions from each unit in the ten-unit system

Power Plants	Fuel	CO_2 Emissions (kg/MWh) [13]
Unit 1-2	Coal	920
Unit 3-7	Natural Gas	452
Unit 8-10	Oil	583