Profit based Self Scheduling of Virtual Power Plant under Multiple Locational Marginal Prices

Meenakshi Khandelwal1, Parul Mathuria2, Rohit Bhakar3
1, 3 Department of Electrical Engineering, Malaviya National Institute of Technology Jaipur, India
2 Department of Electrical Engineering, National Institute of Technology Warangal, India
Email: 1meenakashmitn.ee@gmail.com, 2parulvj14@gmail.com, 3rbhakar.ee@mnit.ac.in

Abstract—Integration of DERs and prosumers as a single plant to obtain allied benefits via market interface introduces the concept of Virtual Power Plant (VPP). This aggregation imposes techno-economic challenges on VPP operator while participating into LMP based wholesale market. Moreover, widely dispersed DERs connected at different nodes with transmission bus experiences multiple Locational Marginal Prices (LMPs). This would impact VPP scheduling and trading decisions, hence require in-depth investigations. In this regard, this paper presents a mathematical exposition for network constrained VPP scheduling with LMP based wholesale market participation. IEEE 30-bus system is modified to implement the proposed model. Results demonstrate that multiple LMPs substantially help VPP operator in optimal resource allocation while maintaining network flows within limits. Further, power mismatch is traded into LMP based market through multiple nodes to maximize its profit. Proposed model would help VPP operator to maintain a consistent system in view of technical and market aspects.

Index Terms—Interruptible load, locational marginal price, optimal power flow, scheduling, virtual power plant, wholesale market.

I. INTRODUCTION

RENEWABLE generation technological advancements and consumers’ active participation in deregulated environment emanated a need for managing operational complexities of the modern power system. Clustering of conventional Distributed Generators (DGs), storage technologies, electric vehicles, renewable generation and active demand response as Distributed Energy Resources (DERs) provides solution to these complexities upto some extent. However, there is a need for congruous techno-economic solutions to address these issues in current power system scenario. In this prospect, aggregation of heterogenous DERs to act as a single operating profile introduces the concept of Virtual Power Plant (VPP) [1,2].

This aggregation offers an opportunity to small power plant owners and prosumers for electricity market access along with compensation of systems’ unexpected power fluctuations. This accommodates dispersed resources to collectively participate into electricity market (Commercial VPP) or to provide system management services (Technical VPP) [3]. Thus, VPP notably increases system reliability, security and stability through interaction among power grid resources, energy consumers and intelligent elements [4].

VPP operator aggregates dispersed heterogeneous units for power balancing and participates into electricity market with the aim of profit maximization. It acts as a mediator between DERs and market for optimal energy management, through energy loss and generation cost minimization [5]. It manages power output of all DERs for optimal resource allocation, subject to supply-demand balance, line flow limits and DER capacity limits and other technical constraints [6]. Demand Response (DR) is an efficient and cost-effective way of smart consumers to participate into energy market through price and incentive-based mechanisms. These methods would significantly help to avoid power system contingencies and blackouts [7].

VPP with centrally controlled coalition participates in wholesale trading where it faces single or multiple Locational Marginal Prices (LMPs), as per its points of connection with transmission grid [8]. Single or multiple LMP consideration would largely impact physically connected VPP constituent behaviour. Due to huge dispersion of VPP coalition units, multiple nodal LMPs are required to be considered for prudent modelling. This would impact VPP operator scheduling and trading strategies. VPP scheduling with market participation via multiple nodal LMPs while managing feasible internal power flow is not much focussed in literature. From best of the authors’ knowledge, profit-based network constrained VPP scheduling with technical modelling of DERs, aggregating energy storage and demand response considering multiple LMPs has not been reported in literature.

This paper proposes a DC optimal power flow-based VPP scheduling with multiple nodal LMP consideration for participation into wholesale electricity market. The work considers technical modelling of VPP constituents such as DGs (conventional generation), DERs (PV and Wind based), interruptible load, storage and demand response to analyse the impact of LMPs on economic and operational performance of VPP. Results demonstrate impact of multiple LMP consideration in VPP profit maximizing. Additionally, sensitivity analysis of interruptible load is also carried out to find the optimal value interruptible load cost coefficient.

II. PROBLEM DESCRIPTION

VPP operator aggregates dispersed heterogeneous DERs to act as a single operating profile with the aim to optimize its profit. As the units are not located at a single location, single LMP consideration could not be sufficient for optimal scheduling and would not lead to best solution. This work considers VPP to be connected at different points with transmission grid and hence multiple LMPs at various locations are considered to model profit-based scheduling of VPP coalition members. This would contribute to provide an approach which would assist VPP operator for more effective real-time scheduling decisions, while enhancing its own benefit.

The objective function is formulated as VPP operator profit maximization subject to network and DERs technical constraints. Profit is formulated as difference between revenue from market trading and cost of energy sourced from VPP coalition members. Conventional generators, renewable units, energy storage and interruptible loads are considered as VPP...
coalition members. VPP owned system is assumed to be connected through transmission bus from multiple LMP nodes. Power trading is performed only in day-ahead spot market and inflows/outflows for each time interval are evaluated in order to maximize VPP operator’s profit. For internal power flow modelling, DC optimal power flow has been considered. For scheduling a usual time span of 24-hours is considered to study the impact of aggregation functioning as a single operating profile.

III. MODELING OF VPP CONSTITUENTS

A. Dispatchable Generation Units

VPP model considers small diesel and gas generators as controllable units to supply varying load and maintain power balance. The operator decides commitment schedule of these units so as to minimize total operating cost. Total cost of these generators, \( C_d(t) \) is defined as sum of fuel, start-up and shut down costs, modelled in Eqn. (1), subject to constraints (2) to (9).

\[
C_d(t) = \text{fuel} + \text{startup costs} + \text{shutdown costs} \quad \forall d, \forall t \tag{1}
\]

\[
\text{fuel} = \text{SUC}_d(t) + \text{SDC}_d(t) \quad \forall d, \forall t \tag{2}
\]

\[
\text{startup costs} = s_{d}^{\text{up}} * y_d(t) \quad \forall d, \forall t \tag{3}
\]

\[
\text{shutdown costs} = s_{d}^{\text{down}} * z_d(t) \quad \forall d, \forall t \tag{4}
\]

\[
p_{d}^{\text{min}} * v_d(t) \leq P_d(t) \leq p_{d}^{\text{max}} * v_d(t) \quad \forall d, \forall t \tag{5}
\]

\[
y_d(t) + z_d(t) \leq 1 \quad \forall d, \forall t \tag{6}
\]

\[
-R_{d}^{\text{down}} \leq P_d(t) - P_d(t-1) \leq R_{d}^{\text{up}} \quad \forall d, \forall t \tag{7}
\]

\[
\sum_{t=MUT_d+1}^{24} y_d(t) \leq v_d(t) \quad \forall d, \forall t \in [MUT_d, T] \tag{8}
\]

\[
\sum_{t=MDT_d+1}^{24} z_d(t) \leq 1 - v_d(t) \quad \forall d, \forall t \in [MDT_d, T] \tag{9}
\]

where \( d \) and \( t \) are sets of dispatchable generation unit and time respectively. \( b \) is linear cost coefficient in $/MWh. \( \text{SUC}_d(t) \) and \( \text{SDC}_d(t) \) are start-up and shut-down costs of dispatchable generators respectively. \( P_d(t) \) is quantum of power supplied by the unit at time \( t \). Constraint (2) states the minimum power, \( p_{d}^{\text{min}} \) and maximum power, \( p_{d}^{\text{max}} \) limits of dispatchable generating units. Constraint (3) determines startup \( y_d(t) \) and shutdown \( z_d(t) \) status of generators at time \( t \). \( v_d(t) \) is the commitment status of generator \( d \) at time \( t \). Constraint (4) restricts the generator to start and shutdown at the same time. Constraint (5) sets ramping limits on the generating unit. \( R_{d}^{\text{down}} \) and \( R_{d}^{\text{up}} \) are ramp down and ramp up limits of the generator. Constraint (6) and (7) signify the minimum up time, \( \text{MUT}_d \) and minimum down time, \( \text{MDT}_d \) of the unit.

B. Intermittent Generation Units

Solar and wind power generation units are considered as intermittent units of the model. Cost of these units is considered zero as no fuel cost is associated with them. Generation from renewables is considered from their historical data pattern. Due to network constraints, a portion of renewable generation may have to be curtailed at times. In such case, cost of curtailment is equal to loss of extra cost energy, which has to be borne by the operator. However, with storage such curtailments can be avoided. Present modelling avoids to consider renewable curtailment and forces the operator to manage this excess renewable generation through storage or market trading.

C. Energy Storage Units

Energy storage plays a crucial role in VPP operator profit maximization. It is considered in VPP model in aggregation with other generating profiles for power balancing. The operator schedules energy storage units for charging and discharging in response to availability/shortage of energy at minimum energy cost. Power, \( P_s(t) \) and energy, \( E_s(t) \) balance of storage devices at any period is modelled as Eqn. (10) and (11), subject to constraints (12) to (16).

\[
P_s(t) = P_s(t-1) + P^{\text{ch}}(t) - P^{\text{dis}}(t) \quad \forall s, \forall t \tag{10}
\]

\[
E_s(t) = E_s(t-1) + P^{\text{ch}}(t) * \eta_c - \frac{1}{\eta_d} * P^{\text{dis}}(t) \quad \forall s, \forall t \tag{11}
\]

\[
P^{\text{min}} \leq P_s(t) \leq P^{\text{max}} \quad \forall s, \forall t \tag{12}
\]

\[
P^{\text{ch, min}} * c_s(t) \leq P^{\text{ch}}(t) \leq P^{\text{ch, max}} * c_s(t) \quad \forall s, \forall t \tag{13}
\]

\[
P^{\text{dis, min}} * d_s(t) \leq P^{\text{dis}}(t) \leq P^{\text{dis, max}} * d_s(t) \quad \forall s, \forall t \tag{14}
\]

\[
c_s(t) + d_s(t) \leq 1 \quad \forall s, \forall t \tag{15}
\]

where \( s \) is set of energy storage devices. \( P^{\text{ch}}(t) / P^{\text{dis}}(t) \) is the power taken/delivered by storage during charging/discharging processes. \( \eta_c \) and \( \eta_d \) are charging and discharging efficiencies associated with energy losses of the storage unit. Constraint (12) and (13) states power and energy limits of the storage device. \( E^{\text{min}}_s \) and \( E^{\text{max}}_s \) are minimum and maximum energy limits; \( P^{\text{min}}_s \) and \( P^{\text{max}}_s \) are minimum and maximum power limits of the storage unit. Constraints (14) and (15) signify charging and discharging limits of the device. \( P^{\text{ch, min}}_s \) and \( P^{\text{ch, max}}_s \) are minimum and maximum charging limits; \( P^{\text{dis, min}}_s \) and \( P^{\text{dis, max}}_s \) are minimum and maximum discharging limits of the storage. \( c_s(t) \) and \( d_s(t) \) are charging and discharging status of the storage. Constraint (16) restricts charging and discharging of storage at the same time interval.

D. Interruptible Load

VPP model considers incentive-based demand response through modelling of interruptible load to manage power imbalances. A prior agreement is signed between VPP and
consumers willing to provide this service. The agreement involves maximum of load to be interrupted, time interval during which interruption is accepted and amount payable for per unit interruption. VPP operator uses this as DR in case of high prices or low generation or both, while maximizing its market profit. Incentives for DR services are modelled in Eqn. (17).

\[ C_{int}^{t} = a \times P_{i}^{int}^{t} \quad \forall i, \forall t \]  

(17)

\[ 0 \leq P_{i}^{int}^{t} \leq k_{i} \times P_{i}^{load}^{t} \quad \forall i, \forall t \]  

(18)

where \( a \) is interruptible load cost coefficient. \( P_{i}^{load}^{t} \) is total load at bus \( i \) and \( P_{i}^{int}^{t} \) is amount of load interrupted at any time interval \( t \). Constraint (18) defines amount of load available for interruption at any node \( i \). \( k_{i} \) is the percentage load available for interruption, out of the total load.

IV. POWER DISPATCH MODEL

VPP operator aggregates dispersed DERs to supply localized loads and maximize its profit by virtue of market interface. Power consumption/generation from VPP constituents is adjusted to attain maximum profit, while trading aggregated outcome into the market. Moreover, market prices are continuously varying in each time slots hence the outcome of VPP (generation and consumption) needs to be adjusted in each hour.

VPP operator profit is modelled as Eqn. (19). It contains two components, i.e., revenue and cost. The operator maximizes its profit by maximizing the difference between two i.e., by maximizing revenue and minimizing cost. It earns revenue by virtue of market interface, trading at different LMPs via different grid nodes. It procures/sells electricity from wholesale market as per applicable LMP while maintaining network flows within limit. Cost of dispatchable generation and load interruption is borne by the operator. It operates the constituent units within technical limits, while minimizing the total cost.

\[
\text{Max VPP Profit} = \sum_{i} \left( \sum_{j} A_{ij}^{LMP} P_{i}^{t} + \sum_{j} C_{ij}^{LMP} P_{j}^{t} - \sum_{j} C_{ij}^{int} P_{j}^{int} \right) \quad \forall t
\]  

(19)

\[
P_{ij}^{t} = \frac{1}{X_{ij}} \left( \delta_{j} - \delta_{i} \right) \times 100 \quad \forall j \in \mathbb{R}_{ij}^{+}, \forall t
\]  

(20)

\[
-P_{ij}^{lim} \leq P_{ij}^{t} \leq P_{ij}^{lim} \quad \forall j \in \mathbb{R}_{ij}^{i}, \forall t
\]  

(21)

VPP operator determines optimal power dispatch schedule of its coalition units while maintaining line power flows within limits. Line power flow is modelled based on DCOPF via Eqn. (20). Thermal limits of lines are restricted by Eqn. (21). VPP power balance is modelled as Eqn. (22) to (24) for balanced inflows and outflows. Positive and negatives value of power at nodal LMPs indicates power sold and procured, respectively. Eqn. (22) determines power balance at the nodes connected with transmission grid, i.e., LMP nodes while Eqn. (23) checks balance at other nodes of the test system. Eqn. (24) validates net power balance of the system at every scheduling interval.

\[
\sum_{d} P_{d}^{t} + \sum_{w} P_{w}^{t} + \sum_{a} P_{a}^{t} + \sum_{s} \left( P_{s}^{dis} - P_{s}^{dis} \right) = \sum_{i} P_{i}^{load}^{t} + \sum_{j} P_{j}^{int}^{t} + \sum_{r} P_{r}^{trade}^{t} \quad \forall i \in n, \forall t
\]  

(22)

\[
\sum_{d} P_{d}^{t} + \sum_{w} P_{w}^{t} + \sum_{a} P_{a}^{t} + \sum_{s} \left( P_{s}^{dis} - P_{s}^{dis} \right) = \sum_{i} P_{i}^{load}^{t} + \sum_{j} P_{j}^{int}^{t} + \sum_{r} P_{r}^{trade}^{t} \quad \forall i \neq n, \forall t
\]  

(23)

\[
\sum_{d} P_{d}^{t} + \sum_{w} P_{w}^{t} + \sum_{a} P_{a}^{t} + \sum_{s} \left( P_{s}^{dis} - P_{s}^{dis} \right) \leq \sum_{i} P_{i}^{load}^{t} + \sum_{j} P_{j}^{int}^{t} + \sum_{r} P_{r}^{trade}^{t} \quad \forall t
\]  

(24)

where \( i, j \) is set of system nodes and \( r \) is set of intermittent units. \( n \) is set of nodes with point of LMP connections. \( R_{i}^{+}, R_{i}^{-}, R_{i}^{i} \) are sets of dispatchable generator units, intermittent generator units, energy storage units and buses, respectively connected at node \( i \). \( P_{r}^{trade}^{t} \) defines quantum of power traded with nodal LMPs. \( LMP_{i}^{t} \) is locational marginal price at node \( i \). \( P_{ij}^{limit} \) is thermal limit of line connected between node \( i \) and \( j \).

V. CASE STUDY, RESULTS AND ANALYSIS

A. Data

Modified IEEE 30-bus system is taken as VPP test model connected at distribution end, as shown in Fig. 1. VPP test model aggregates 60% of total generation of the standard system with four dispatchable generator units and two energy storage units. Details of dispatchable and energy storage units is shown in Tables I and II respectively. Aggregated renewable penetration of 70% from two wind and two solar units is considered, representing high renewable share in VPP. Test system consists of 17 fixed demand and 5 interruptible load buses with 13.46 MW as peak load, which is 60% of the standard system. It is assumed that VPP is having accessibility right over only 50% network of the actual standard system.

Solar radiation and wind speed historical data of 24 hours from Pennsylvania, USA for September, 2017 is converted into equivalent power output [9]. This is assumed as generation profiles of intermittent generator units, as shown in Fig. 2. with 60% of the system load i.e. 13.46 MW as peak load. VPP test system is assumed to be connected with transmission grid at 3 nodes, i.e., Bus 1, 15 and 30 where it faces different LMPs. LMP data for these three nodes is taken from PJM market of September, 2017 [10] for three different locations: APS, AECO and AEP, as shown in Fig. 3. Maximum power limit that could be traded into wholesale market at each LMP is 30 MW. The study focuses VPP day-
ahead scheduling and operator’s profit maximization with trading into LMP based wholesale electricity market with each hour as trading/scheduling interval over 24-hours planning horizon.

Table I

<table>
<thead>
<tr>
<th>Specifications</th>
<th>Unit-1</th>
<th>Unit-2</th>
<th>Unit-3</th>
<th>Unit-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (MW)</td>
<td>4</td>
<td>5</td>
<td>5.5</td>
<td>7</td>
</tr>
<tr>
<td>Minimum Output (MW)</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Ramp Up Limit (MW/h)</td>
<td>1</td>
<td>1.25</td>
<td>1.375</td>
<td>1.75</td>
</tr>
<tr>
<td>Ramping Down Limit (MW/h)</td>
<td>1</td>
<td>1.25</td>
<td>1.375</td>
<td>1.75</td>
</tr>
<tr>
<td>Linear Cost ($/MWh)</td>
<td>37</td>
<td>40</td>
<td>35</td>
<td>45</td>
</tr>
<tr>
<td>Start Up Cost ($)</td>
<td>20</td>
<td>20</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>Shut Down Cost ($)</td>
<td>25</td>
<td>25</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Minimum Up Time (h)</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Minimum Down Time (h)</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Initial Status</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Initial Power Output (MW)</td>
<td>1.3</td>
<td>0</td>
<td>0</td>
<td>1.3</td>
</tr>
</tbody>
</table>

Figure 1 VPP test model

Table II

<table>
<thead>
<tr>
<th>Specifications</th>
<th>Unit-1</th>
<th>Unit-2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Capacity (MW)</td>
<td>9</td>
<td>7</td>
</tr>
<tr>
<td>Minimum Power Output (MW)</td>
<td>1.8</td>
<td>1.4</td>
</tr>
<tr>
<td>Charging/Discharging Lower Limit (MW/h)</td>
<td>0.72</td>
<td>0.56</td>
</tr>
<tr>
<td>Charging/Discharging Upper Limit (MW/h)</td>
<td>3.6</td>
<td>2.8</td>
</tr>
<tr>
<td>Energy Capacity (MWh)</td>
<td>8.1</td>
<td>6.3</td>
</tr>
<tr>
<td>Minimum Energy Limit (MWh)</td>
<td>1.62</td>
<td>1.26</td>
</tr>
<tr>
<td>Charging efficiency</td>
<td>0.9</td>
<td>0.93</td>
</tr>
<tr>
<td>Discharging efficiency</td>
<td>0.8</td>
<td>0.8</td>
</tr>
</tbody>
</table>

Figure 2 Generation profile of renewables

Figure 3 LMP profile at three different locations taken from PJM market

B. Simulation Results and Analysis

Simulations are performed to maximize VPP profit, subject to various technical constraints described in Sections III and IV. Problem is MILP in nature with 3,745 variables and 384 discrete variables. It has been solved using commercially available software GAMS® using its CPLEX solver on Intel®, CoreTM, i7 CPU, 2.40 GHz and 8 GB of RAM laptop [11]. Average execution time is 0.024 seconds for 24-hour analysis.

Figure 4 Aggregated dispatch profile of VPP constituents

Fig. 4 illustrates aggregated dispatch profile of VPP constituents and quantum of power traded through LMP based wholesale market. It demonstrates how VPP units are contributing for local power balance and market trading, while maximizing operator’s profit. From Hour 1 to 3, renewable generation is more than load, so operator sells remaining power into the market. At Hour 4, LMP is minimum of total trading interval, so the operator charges its storage units from intermittent generator units and remaining from market procurement, to make it available during peak hours.
Hours 5 to 9, renewable generation is inadequate to meet VPP loads, hence operator maintains power balance through market procurement due to comparatively low prices. During this period, conventional units are not employed because of high starting and operating cost. From Hours 10 to 19, spare generation is sold in market to make profit. During Hours 12 to 22 with high LMP period, operator reduces its market procurement and uses its own dispatchable generator and energy storage units to supply net load, subject to constraints (1) - (16). Dispatchable generator units follow LMP curve during this period. For Hours 21 to 24, LMP is low, so the operator procures power from market to supply net load. Energy storage units are deployed during high LMP periods i.e., Hour 16 and 17 to maximize the profit.

![Fig. 5 Generation profile of dispatchable units](image)

Fig. 5 describes generation schedule of each dispatchable unit. It could be noted that the operator commits these units during high market prices and maximize its profit by selling power into the LMP based wholesale market. However, these units are put to off due to high operating cost as compared to market price during off-peak periods. Fig. 6 describes charging and discharging schedule of each energy storage unit. During Hour 4, when market prices are low, these units are charged to their maximum level. At Hour 16 and 17, when market prices are high, these units are discharged to make profit by selling power into the market. Therefore, it is observed that during high prices, operator reduces its market procurement and deploys dispatchable generator and energy storage units to maximize its profit.

![Fig. 6 Charging and discharging patterns of energy storage units](image)

Fig. 7 represents quantum of power traded at each LMP node. Negative/positive values indicate power procured/sold from/into the market. It could be seen from Fig. 3 that LMP at AECO is minimum, hence the operator is procuring power from this node up to its maximum limit during entire trading interval. However, at nodes APS and AEP, the operator is continuously exporting power because of high prices so as to maximize its profit. Further, the quantum of power traded into/from the market at any time depends upon the power flows and balancing conditions of the test system.

![Fig. 7 Energy allocation at each LMP node](image)

Fig. 4, 5, 6 and 7 represents optimal resource allocation of VPP for maximum profit in 24 hours. For this case study, cost of interruptible load is considered high i.e., 55 $/MWh and hence there is no load interruption.

![Fig. 8 Sensitivity analysis of interruptible load](image)

Fig. 8 shows sensitivity analysis of interruptible load to study its impact on VPP profit. Interruptible load is varied from $25/MWh to $55/MWh. It could be observed that at $55/MWh, it is not economical for operator to interrupt load. Hence, at this rate no load is interrupted. As market price substantially affects amount of load interruption, this sensitivity analysis contributes to model the VPP operator uncertainties. Further, an optimal value of interruptible load cost coefficient could be selected from this analysis through trade-off between load interruption and VPP profit.

This could be observed that VPP aggregation helps to suppress varying renewable output by trading surplus in the market from Hour 1 to 3 and from Hour 10 to 16. For compensating renewables and demand variations, storage also
supports as seen at Hour 3 to 5 and Hour 15 to 18. For this work, it is assumed that market is sufficiently liquid and outside VPP power transactions are feasible.

VI. CONCLUSION

This paper presents modelling of VPP components to optimize operator benefits with optimal scheduling considering the impact of network constraints. The model reflects benefits of multiple LMP consideration for wholesale market trading on scheduling of VPP units. The proposed model alleviates congestion issues of the VPP by maintaining network flows and VPP inflows/outflows within technical limits. Energy exchange between VPP and grid is energy traded in market to decide optimal procurement/sell from/to market to attain maximum benefit. Furthermore, sensitivity analysis of interruptible load is done by varying its cost coefficient to obtain an optimized value of interruptible coefficient. This analysis demonstrates that the operator profit and amount of load interrupted decreases with increase in cost coefficient. The proposed model provides deterministic approach for the VPP to maximize its profit maintaining a reliable power supply within VPP. As future work, uncertainty associated with the renewables and LMPs will be modelled to enhance practical applicability of the proposed approach.

REFERENCES


