The Impact of Dispersed PV Generation on Ramp Rate Requirements

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***Abstract*— PV generation variability and uncertainty significantly influence operation of the power systems with high penetration of PV sources. The potential impact of distributed PV generation on ramp rate requirements in the IEEE 24-bus system is evaluated in this paper. PV generation and load are, here, probabilistically modeled using actual data and curve fitting approach. Probabilistic unit commitment (UC) based on unit de-commitment method combined with two point estimate method (2-PEM) is used to determine the ramp rate required to compensate for the PV power fluctuations. The proposed method considers stochastic factors and their effects on the dispatch results. Two scenarios are studied to evaluate the dispersed PV generation and its potential to reduce the ramp rate requirement of conventional generators. Ramping requirements of the system are calculated for 6 hours ahead scheduling period and different PV penetration levels, which lend the authors a hand in a conclusion concerning the applicability and efficiency of the proposed method.**

***Index Terms*-- Distributed PV generation, ramp rate requirements, stochastic modeling, two point estimate method (2-PEM), unit commitment, unit de-commitment.**

I. Introduction

Photovoltaic energy has become a significant source of power generation in many electric utility systems across the United States. These green generators have been significantly installed over the last five years and have revealed their pros and cons [1]. The current capacity of PVs is now less than 1% of peak load demand; however, it is predicted to cover 5% to 10% in a decade away [2].

On the other hand, power plants are deemed to be the responsible for nearly 40% of the nation's carbon dioxide emissions. This has led to significant environmental and other interest groups to target this sector. One of the commonest policies in this response is known as a renewable portfolio standard (RPS). This standard guarantees a minimum amount of renewable energy, e.g., wind, solar, biomass, or geothermal energy, in the portfolio of generating resources.

Solar cells are commonly facing a great concern that is the obvious variability and uncertainty of their output power. In response, a sufficient amount of reserve margin should be assigned which may significantly affect the system operating costs. This required reserve margin might be accessible via the conventional fast response units [3].

So far, some solutions to the aforementioned concern have been investigated [4]-[9]. Once an efficient short-term forecasting is established, a robust probabilistic process should be conducted to deal with the employed dispersed renewable energies. Some analyses are also conducted on the performance of PVs to investigate their impacts on electric utility's load shape [10]. Many methods have been under discussion handle the variable characteristics of PV generation. Overvoltage problems are studied in [5] and managed through power curtailments.

In addition to the conventional concerns, noteworthy is that those generating units with quick start capability or fast ramp rate can provide the load following service, ranging from 10 minutes to a few hours, to maintain the system balance [11]. Scheduling and unit commitment commonly correspond to time scales that may range from several hours or days ahead of the real-time schedule to plan for the required quantity of generation and load following capability [3]. Several studies represent that the cost assigned to scheduling and unit commitment services accounts for a significant portion of the system operating cost increases when compared with the regulation and load following costs [11], [12].

Adequate ramp rate requirements provided by the scheduling services may significantly affect the system operating costs. Increased variability of the electric power due to the intermittent nature of the renewable energy resources requires our power system to be equipped with greater flexibility from the conventional generating units. This can be satisfied with greater ramping capability which is required to compensate for PV power output variability and maintain the system balance for a day ahead scheduling [13].

This paper evaluates distributed PV generation and its potential impacts on the ramp rate requirements. Probabilistic modeling of PV and load is conducted based on actual data in Section II. This Section explains the unit commitment methodology based on unit de-commitment method and two point estimate method (2-PEM). Different cases are studied in Section III and their simulation results are presented. Conclusions are finally remarked in Section IV.

II. Methodology

A. Probabilistic Modeling of PV and Load

Due to the stochastic nature of PV and the load, some degree of uncertainty is imposed in power systems with high levels of PV power generation. In order to represent the random characteristics of PV output power [9] and load

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[13], their variability and random behavior need to be modeled probabilistically. Using the curve fitting approach, a Normal probability distribution function (PDF) is assigned to the historical hourly PV data gathered from the BPA balancing authority [14]. The same procedure is applied to the historical load data and a Normal PDF is acquired using the curve fitting approach.

B. Unit Commitment Problem Based on PEM

The deterministic model for unit commitment cannot comprehensively represent the influences of the stochastic factors on the dispatch results, if PV power output and load variation are probabilistically modeled [15]. Uncertain factors such as PV output power and variable loads can be considered in unit commitment computations by using a probabilistic unit commitment (PUC). Several methods have been proposed to perform the probabilistic analysis in PUC problems. These methods are classified as simulation and approximate methods [16], [17]. Monte-Carlo simulation (MCS) is a simple and accurate simulation method to find the probability distribution functions (PDFs). However, the large computation effort is the main obstacle for efficient use of this method.

PEM has been regarded as an appropriate probabilistic method because of its accuracy, simplicity, and speed. The PEM [18] have been proposed to reduce the computational burden of the probabilistic analysis. This method was developed by Rosenblueth in the 1970s for calculating the moments of a random multi variable quantity [18]. 2PEM which is a variation of the original PEM is applied in this paper to model the uncertainties. The proposed PUC is based on unit de-commitment and PEM. Unit de-commitment procedure provides a mechanism for completely shutting down the very expensive generators and finding a least cost commitment and dispatch. This will result in an economic operation of the system over the scheduling time period. Vectors of input and output random variables are given by equations (1) and (2), respectively.

$$X = [PV\ \ Gen,\ Load] \quad (1)$$

$$Y = [RR, OC] \quad (2)$$

where PV generations and loads are the input probabilistic variables and ramp rate requirements (*RR*) and total operation cost, *OC,* are the output probabilistic variables.

The moments of the random variables are derived based on the distributions of the PV generations and the loads. Two estimate points are chosen from every distribution, and then the corresponding weighting coefficient and the probability concentration at each point are calculated. The deterministic optimal power flow model is then used to dispatch the generation for every estimate point. As all the points are calculated, the results calculated by every point and the corresponding probability concentrations are used to derive the expected value and standard deviation of the dispatch results. The POPF algorithm based on 2PEM is outlined as follows:

1) Assign appropriate PDF to each probabilistic variable including loads and PV generations.

2) $E(Y) = E(Y^2) = 0$

3) Determine the necessary parameters of the 2PEM.

$$\xi_{k,1} = +\sqrt{n} \quad (3.a)$$

$$\xi_{k,2} = -\sqrt{n} \quad (3.b)$$

$$P_{k,1} = P_{K,2} = \frac{1}{2n} \quad (3.c)$$

where $\xi_{k,1}$, $\xi_{k,2}$, $P_{k,1}$ and $P_{k,2}$ are the locations and probabilities of concentrations.

4) Set $k = 1$.

5) Set the concentrations ($x_{k,1}$ and $x_{k,2}$) and run the deterministic OPF using the input vector *X*.

$$x_{k,1} = \mu_{X,k} + \xi_{k,1} \cdot \sigma_{X,k} \quad (4.a)$$

$$x_{k,2} = \mu_{X,k} + \xi_{k,2} \cdot \sigma_{X,k} \quad (4.b)$$

where $\mu_{X,k}$, $\sigma_{X,k}$ are the expected value and standard deviation of the input variables.

$$Z = [\mu_{X_1}, \mu_{X_2}, \ldots, x_{k,i}, \ldots, \mu_{X_n}] \qquad i = 1,2 \quad (4.c)$$

6) Update $E(Y)$ and $E(Y^2)$.

$$E(Y)^{(k+1)} \cong E(Y)^{(k)} + \sum_{i=1}^{2} P_{k,i} \cdot h(Z) \quad (5.a)$$

$$E(Y^2)^{(k+1)} \cong E(Y^2)^{(k)} + \sum_{i=1}^{2} P_{k,i} \cdot h^2(Z) \quad (5.b)$$

7) Set $k=k+1$ and repeat steps 5 and 6 until these steps are done for all random input variables.

8) Calculate the expected value and standard deviation of *Y* using (6.a) and (6.b).

$$\mu_Y = E(Y) \quad (6.a)$$

$$\sigma_Y = \sqrt{E(Y^2) - \mu_Y{}^2} \quad (6.b)$$

C. The Proposed Method

The PUC based on unit de-commitment method and 2PEM is proposed to compute the ramp rate requirements and operation cost of the system. The objective function is composed of the generation costs and startup costs of individual units over the scheduling horizon. This is given in below:

$$OC = Min\left\{\sum_{t\in T}\sum_{i=1}^{n_g}\left(\left(a_i P_{g_i}^2(t) + b_i P_{g_i}(t) + c_i\right)\times U_i(t) + SU_i(t)\right)\right\} \quad (7)$$

where n_g is the number of generating units; a_i, b_i and c_i are the cost function coefficients of unit *i*; $P_{g_i}(t)$ is the unit *i* generation output at time *t*; $U_i(t)$ and $SU_i(t)$ are the commitment state and startup cost of unit *i* at time *t,* and *T* is the scheduling period, respectively.

The UC constraints include the unit generation limits (8), system power balance constraints (9), unit ramping up limits (10), and unit ramping down limits (11) listed below:

$$P_{g_i,\min} \times U_i(t) \le P_{g_i}(t) \le P_{g_i,\max} \times U_i(t) \qquad (i = 1,2,\ldots,n_g; t\in T) \quad (8)$$

where $P_{g_i,\min}$ and $P_{g_i,\max}$ are the lower and upper limits of power generation of unit *i*, respectively.

$$\sum_{i=1}^{n_g} P_{g_i}(t)\times U_i(t) = P_D(t) + P_L(t) \quad t\in T \tag{9}$$

where $P_D(t)$ and $P_L(t)$ are the system demand and losses at time interval *t*.

$$\begin{aligned} P_{g_i}(t) - P_{g_i}(t-1) \le \left[1-U_i(t)\left(1-U_i(t-1)\right)\right]UR_i \\ + U_i(t)\left(1-U_i(t-1)\right)P_{g_i,\min} \\ (i=1,2,...,n_g; t\in T) \end{aligned} \tag{10}$$

where UR_i is the ramp-up rate limit of unit *i.*

$$\begin{aligned} P_{g_i}(t-1) - P_{g_i}(t) \le \left[1-U_i(t-1)\left(1-U_i(t)\right)\right]DR_i \\ + U_i(t-1)\left(1-U_i(t)\right)P_{g_i,\min} \\ (i=1,2,...,n_g; t\in T) \end{aligned} \tag{11}$$

where UD_i is the ramp-down rate limit of unit *i.*

Ramp rate requirement of a generating unit is defined as the difference between the optimal dispatches of that unit over a specified time period to compensate for the PV power output variability. To this end, the expected value and standard deviation of the dispatch results are calculated using PUC without the ramping constraints (10), (11). Ramping rate of the generating unit *i* over the one time interval *t* is calculated by the following equation:

$$RR_i(t) = \left|P_{g_i}(t) - P_{g_i}(t-1)\right| \quad t\in T \tag{12}$$

where $RR_i(t)$ is the ramping rate of the generating unit *i* to compensate for PV power fluctuation over the one hour interval *t*; $P_{g_i}(t)$ and $P_{g_i}(t-1)$ are the optimal dispatch of conventional unit *i* at time *t* and *t-1,* respectively. Total ramping requirement of the system is calculated as follows:

$$RR_{Total} = \sum_{i=1}^{n_g}\sum_{t\in T} RR_i(t) \tag{13}$$

Maximum ramping requirement of the system at each hour is defined as the ramping rate of the unit with highest or lowest level of ramping for the given period and is formulated as follows:

$$RR_{\max}(t) = Max\left\{RR_1(t),\ RR_2(t),...RR_{n_g}(t)\right\} \qquad t\in T \tag{14}$$

where $RR_{\max}(t)$ is the maximum ramping requirement of the system at each time interval. Applying this procedure over a 6 hour period determines the maximum ramping requirement of the system for the day ahead scheduling.

$$RR_{\max} = Max\ \{RR_{\max}(t_1),\ RR_{\max}(t_2),...,\ RR_{\max}(t_T)\} \tag{15}$$

where RR_{max} is the maximum ramp rate requirement of the system for the day ahead scheduling. Total maximum ramping requirement of the system is defined as the summation of the maximum ramping requirement at each time interval for the 6 hours ahead scheduling period.

$$RR_{\max-Total} = \sum_{t\in T} RR_{\max}(t) \tag{16}$$

D. Flowchart

The flowchart of the proposed methodology is presented in Fig. 1. According to this flowchart, PV and load data are taken as the inputs to this flowchart. A PDF is assigned to each of the input variables using the curve fitting approach. Unit commitment based on unit de-commitment method and 2PEM is utilized to derive the expected value and standard deviation of the dispatch results. Neglecting the ramping constraints of (10) and (11), ramping requirements of the system are calculated for the 6 hours ahead scheduling period to compensate for the PV power variability. 6-hour period of a day when PV energy is available is selected for this study. Ramping limits of (10) and (11) are then applied considering the ramping requirements calculated in the previous step. UC is then utilized to derive the expected value and standard deviation of the generation outputs and calculate the optimal operation cost of the system over the scheduling horizon.

III. Case Studies

Two scenarios and their simulation results are demonstrated in this section using the IEEE 24-bus test system. Reference [19] illustrates the IEEE 24-bus system. For these scenarios, the penetration level is defined as the ratio of the installed PV capacity to the peak load. The studied power system has a maximum load of 3467 MW. All generating units are committed for the first time interval of the scheduling period. To reach an economic operation, some units should be considered for shutdown over the remaining hours of the scheduling period. A list of candidate units which are more expensive than others is selected. Based on this list, a set of units are selected to be shut down to have the minimum operation cost. Generating unit data for the IEEE 24-bus system are given in the Appendix.

A. Scenario I- Impact of Dispersed PV Generation on the Ramp Rate Requirements

In scenario I, three different cases are evaluated in order to examine the impacts of dispersed PV generation on ramping capabilities required to deal with PV power fluctuations for the IEEE 24-bus system. Case I corresponds to a concentrated PV generating plant at bus 14. Case II corresponds to Dispersed PV generating plants at buses 14 and 10. Case III corresponds to the dispersed PV generating plants at buses 14, 10 and 20. Same installed PV capacity is considered for Cases I-III. The period of study is 6 hours with 15-min time interval.

Based on the 15-min generations data, the correlations of these PV sites are calculated which are -0.1119 (between PV plants at bus 14 and 10), -0.0049 (between PV plants at bus 14 and 20) and 0.1748 (between PV plants at bus 10 and 20).

The maximum ramp rate requirements of the system at each time interval ($RR_{max}(t)$) for Cases I-III over the 6 hours scheduling period and 40% PV penetration level is demonstrated in Fig. 2. As can be seen, the magnitudes of ramping rates supplied by conventional generators increase due to the variable nature of solar generation. Fig. 2 provides a qualitative representation of the PV dispersion impacts on the level of ramping rates that conventional generators need to supply. Therefore, maximum ramp rate requirement of the system at each time interval ($RR_{max}(t)$) is considered as an index to evaluate the ramping capability required to deal with solar power and load fluctuations for the given period. Accordingly, increasing the PV dispersion level from Case I with concentrated PV farm to Case II with two dispersed PV farms and Case III with three dispersed PV farms decreases the maximum ramping requirement of the system at each time interval ($RR_{max}(t)$) for the most part of the scheduling period. This is due to the fact that the deviation of the average total output of the low or uncorrelated PV farms is lower than the deviation of the individual outputs. This will lead to a smoother output from the dispersed PV farms (Case II and Case III) compared to a concentrated one (Case I). Subsequently, the levels of ramping supplied by the conventional generators to compensate for PV power variability are highest for Case I followed by Case II and then Case III for the most part of the scheduling period.

Table I gives the expected value and standard deviation of maximum ramp rate requirements (RR_{max}) and total maximum ramp rate requirements ($RR_{max\text{-}Total}$) of the power

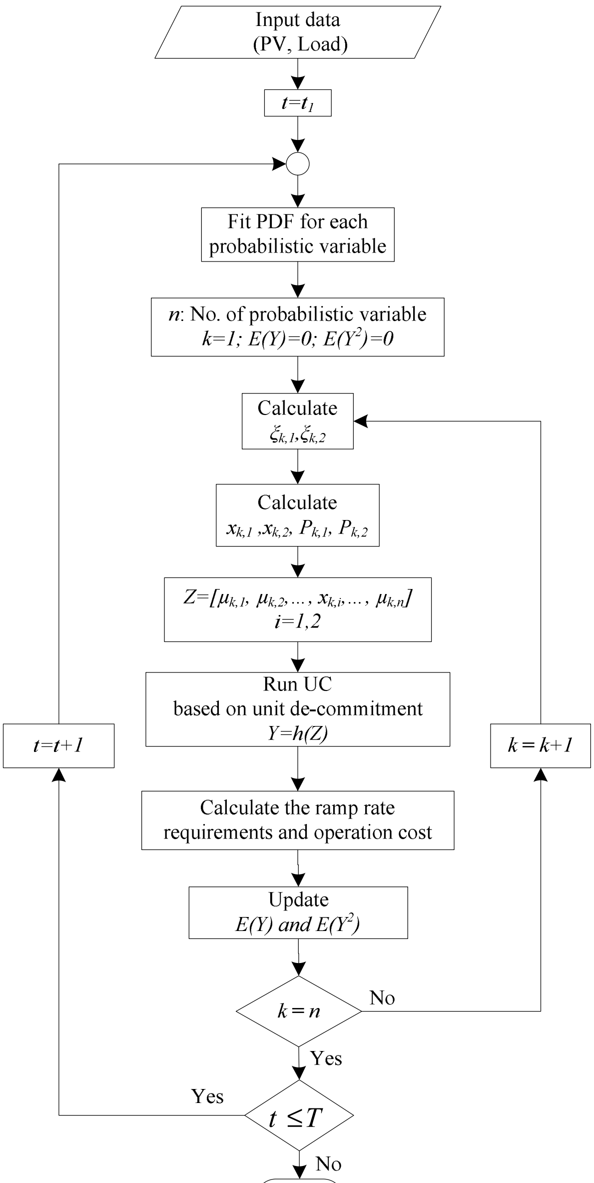

Figure 1. Flowchart for the proposed methodology.

system for the 6 hours ahead scheduling period. These values are calculated for Cases I-III with different PV penetration levels. Considering 20% PV penetration with respect to the peak load, the expected value of the system total maximum ramping requirement ($RR_{max\text{-}Total}$) decreases from 699.625 (MW/15-min) in Case I to 359.430 (MW/15-min) and 293.275 (MW/15-min) in Cases II and III, respectively. The same trend is observed for the system maximum ramping requirement (RR_{max}) in which its expected value decreases from 84.353 (MW/15-min) in Case I to 51.069 (MW/15-min) in Case II and 38.656 (MW/15-min) in Case III. Distributed PV generation has the same impact on ramping requirements of the system with larger PV penetration levels (30% and 40%) and decreases the ramping required to compensate for PV power output variability. This is due to the PV diversity over the given geographical areas which lessen the variability of output power for dispersed PV farms compared to concentrated ones.

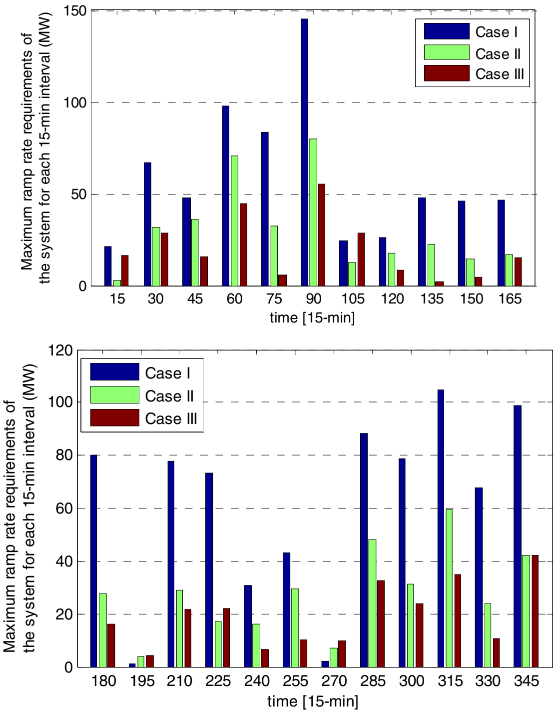

Figure 2. Expected value of the maximum ramping requirements of the system at each time interval $RR_{max}(t)$ for a 6 hours scheduling period with 15-min time interval and 40% PV penetration level.

From Table I, an immediate conclusion of comparing the ramping requirement of the systems with different PV penetration levels is that the ramping requirement for the 6 hours ahead scheduling increases with an increase in PV penetration level. This is due to the increased variability of PV for systems with larger PV penetration levels which requires greater flexibility to deal with. As indicated in Table I, more flexibility can be provided by higher magnitude ramping rates.

Table II gives the expected values of the system total ramping requirement (RR_{Total}). For 20% PV penetration level, increasing the PV dispersion level from Case I with concentrated PV farm to Case II with two dispersed PV farms and Case III with three dispersed PV farms decreases the total ramping requirement of the system from 5351.4 (MW/6-hour) to 2746.0 (MW/6-hour) and 2231.2 (MW/6-hour), respectively. Comparing the total ramping requirement of the systems with different PV penetration levels, it is concluded that an increase in PV penetration level increases the total ramping requirement of the system for the 6 hours ahead scheduling period.

TABLE I. RAMP RATE REQUIREMENTS OF THE SYSTEM FOR THE 6 HOURS SCHEDULING PERIOD AND DIFFERENT PV PENETRATION LEVELS

Penetration Level		$RR_{max\text{-}Total}$ (MW/15-MIN)		RR_{max} (MW/15-MIN)	
		μ	σ	μ	σ
20%	Case I	699.625	22.556	84.353	9.409
	Case II	359.430	10.832	51.069	4.665
	Case III	293.275	7.646	38.656	3.147
30%	Case I	1038.5	36.06	115.462	14.235
	Case II	512.5495	16.842	65.539	7.10
	Case III	369.9015	11.719	46.922	4.812
40%	Case I	1400.2	51.301	145.512	21.053
	Case II	674.01	23.698	80.009	9.543
	Case III	460.87	16.392	55.183	6.434

TABLE II. TOTAL RAMP RATE REQUIREMENTS OF THE SYSTEM FOR THE 6 HOURS SCHEDULING PERIOD AND DIFFERENT PV PENETRATION LEVELS

Penetration Level		RR_{Total} (MW/6 hours)
20%	Case I	5351.4
	Case II	2746.0
	Case III	2231.2
30%	Case I	7834.0
	Case II	3859.2
	Case III	2775.7
40%	Case I	10317
	Case II	4974.8
	Case III	3405.5

The cumulative distribution functions of the system total maximum ramping requirement for 6 hours scheduling period and 40% PV penetration level is represented in Fig. 3. Based on this Figure, for a given ramping level, the probability that the total maximum ramping requirement of the system is less than that level is highest for Case III, followed by Cases II and I, respectively. Accordingly, increasing the PV dispersion level provides the system with more smoothing capability of PV power output and decreases the ramping required to compensate for PV power fluctuations.

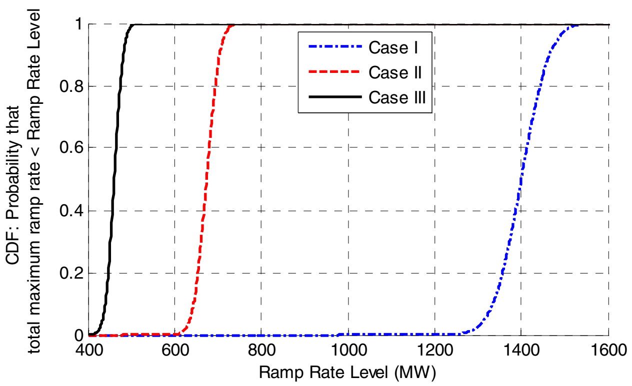

Figure 3. Cumulative distribution of the system total maximum ramping requirement for 6 hours scheduling period and 40% PV penetration level.

The cumulative distribution function of the system maximum ramping requirement for 6 hours scheduling period and 40% PV penetration level is shown in Fig. 4. For a given ramping level in Fig. 4, the probability that the system maximum ramping requirement is less than that level is highest for Case III, followed by Cases II and I, respectively. Accordingly, increasing the PV dispersion level provides the system with more smoothing capability of PV power output and decreases the ramping required to compensate for PV power fluctuations.

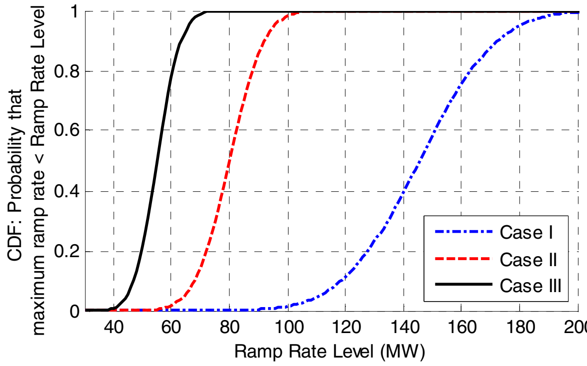

Figure 4. Cumulative distribution of the maximum ramping requirement of the system for 6 hours scheduling period and 40% PV penetration level.

B. Scenario II- Impact of Ramp Rate Limits on the System Operation Cost

Considering the ramping requirements obtained by the unit de-commitment method and 2-PEM, a unit commitment process is performed over the 6 hours ahead scheduling period for different PV penetration levels. System operation costs are calculated for Cases I-III and expected value of the results are given in Table III. As indicated, increasing the PV dispersion level from Case I to Case II and Case III decreases the system operation cost for a certain PV penetration level. This is due to the lower ramping magnitudes required to compensate for the decreased PV variability in the dispersed PV farms compared to a concentrated one. An increase in PV penetration level increases the PV output power in the scheduling process. This will decrease the required conventional generations for meeting the load and lessening the system operation cost for the 6 hours ahead scheduling.

TABLE III. SYSTEM OPERATION COST FOR THE 6 HOURS SCHEDULING PERIOD AND DIFFERENT PV PENETRATION LEVELS

Penetration Level (%)	Ramp rate limit (MW/15-min)	Case #	*OC* (M$/6 hour)
20	40	I	0.4792
		II	0.4450
		III	0.4381
30	60	I	0.4682
		II	0.4242
		III	0.4213
40	100	I	0.4598
		II	0.4206
		III	0.4048

Also, impact of PV distribution on system operation cost reduction will be more significant for the systems with higher PV penetration levels.

IV. CONCLUSION

The evaluation of distributed PV generation and its potential impact on the ramp rate requirement and operation cost in power systems with high levels of PV penetration is performed in this paper. Using the curve fitting approach, the PV and load are stochastically modeled. Probabilistic unit commitment based on unit de-commitment and two point estimate method is proposed to calculate the ramp rate requirement and operation cost. This method is tested on the IEEE 24-bus system and different case studies are conducted. Based on the obtained simulation results, distributing the PV generating units throughout the IEEE 24-bus system can significantly decrease the ramp rate requirements and cost of conventional energy subjected to the certain level of ramp rate limitations. The results reveal the importance of the diversity of PV farms over a wide geographical area and its potential to compensate for the variability of PV generation.

V. APPENDIX

TABLE IV. CONVENTIONAL GENERATORS DATA

Conventional Generator	Cost Function Coefficients			Startup Cost ($)
	a_i ($/MW^2)	b_i ($/MW)	c_i ($)	
G_1	0.0073	21.05	1313.6	1000
G_2	0.0078	21.04	1168.1	1000
G_3	0.0080	16.19	1078.8	1000
G_4	0.0061	17.26	969.8	1000
G_5	0.0058	21.6	958.2	1000
G_6	0.0068	21.6	958.2	1000
G_7	0.0080	23.9	471.6	1000
G_8	0.0070	23.9	471.6	1000
G_9	0.0078	19.7	445.4	1000
G_{10}	0.0081	16.51	702.7	1000

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