IMPACT OF TIME OF UTILIZATION BASED DEMAND RESPONSE ON CUSTOMER TARIFF AND OPTIMAL SIZING OF DISTRIBUTED GENERATION

Subramanya K[1], Dr. M S Nagaraj[2] Dr. Ananthapadmanabha T[3]

[1] Research scholar, BIT (VTU),, [2] Professor, BIT (VTU), Director MUSE, mysuru[3]

Abstract: *Due to the surge in load demand, the scarcity of fossil fuels, and increased concerns about global climate change, researchers have found distributed energy resources (DERs) to be alternatives to large conventional power generation. However, a drastic increase in the installation of distributed generation (DGs) increases the variability, volatility, and poor power quality issues in the microgrid (MG). To avoid prolonged outages in the distribution system, the implementation of energy management strategies (EMS) is necessary within the MG environment. The loads are allowed to participate in the energy management (EM) so as to reduce or shift their demands to non-peak hours such that the maximum peak in the system gets reduced. Therefore, this article addresses the complication of solutions, merits, and demerits that may be encountered in today's power system and encompassed with demand response (DR) and its impacts in reducing the installation cost and the capital cost of DGs. Moreover, the paper focuses on various communication technologies, load clustering techniques, and sizing methodologies presented.*

Keywords: distributed energy resources; demand response; microgrid; load clustering techniques; sizing methodologies; communication technologies

1. INTRODUCTION

The ever-increasing population has led to a plethora of electricity needs in the country. Existing power systems got overstressed to meet the increased load demands. Though the power generation by the conventional fossil fuel-fired generators is flexible, controllable, and dispatchable, the demerits of these sources are not economic, environmentally unfriendly, and non-sustainable [1]. Moreover, the triple bottom line [2] approach suggests the reduction in global emissions, increasing profits, and achieving maximum benefits for the people. It encourages people to develop in a sustainable manner. Its main objective is to enhance the economic, environmental, and social development of a home or community or organisation. A possible solution is to ameliorate the existing system with the DERs [3], but the output of these sources is stochastic and uncertain in nature. Another possible solution is to deploy a battery energy storage system (BESS) into the existing MG to meet the power balance condition, but it is a costly solution. A localized grouping of DGs, BESS, and scattered loads form a MG [4].

The proposed work addresses the complication of solutions, merits, and demerits that may be encountered in today's power system and encompasses demand response (DR) and its impacts in reducing the installation cost, the capital cost of DGs, and total electricity tariff. To achieve this an objective function was formulated and an optimal sizing method has been proposed by considering the impact of DR for finding the optimal size of DGs, i.e., WT, PV, and diesel generator. Further, the proposed algorithm clusters the load into ILs and NILs and assigns a priority to the non-essential loads with the order of scheduled times by using TOU pricing. In addition, the paper suggests a limit on the amount of load shift to avoid the issues like rebound effect, increase in marginal price, and operational cost of the MG due to load recovery. Three penetration levels of demand responsive loads were considered, namely, 0%, 5%, and 10%, for studying the impact of DR programs on optimal sizing of the DGs and on consumer tariffs. Figure 1 shows the function of DSM. The collaboration between the BESS and DR programs will enhance the performance of the power system due to the uncertainty present in generation, loads, and electricity price. Decomposition algorithm with three scheduling patterns employed in [17], namely day ahead (DA) scheduling to optimize the expected operational cost of MG, an hour ahead (HA) scheduling to reduce the gap between DA, and real-time (RT) scheduling, and RT scheduling is employed to reduce the real power imbalance.

Figure1. Functions of DSM in MG

2. OBJECTIVE FUNCTION MODELLING

To reduce the above-mentioned concerns such as capital and installation cost minimization and reduction of consumers tariff, the objective function can be modelled which clusters the load as follows. The following are the objectives to be solved.

• Minimize the size of DGs in the power system.

• Minimize the consumer's electricity bill and improve the load factor.

Minimize, Cost f unction = $(F_{capital} + F_{installation} + F_{customers\ bill})$ ………(1)

Minimize total cost of installation:

$f_1 = TC = \sum_{i=1}^{n} \text{Ccap} + \text{Cmaintenance} + \text{Creplacement}$ …………(2)

$$\varnothing^t = \begin{cases} \varnothing_{off},\ if\ t \in T_{off} \\ \varnothing_{mid},\ if\ t \in T_{mid} \quad \forall\ T\ \in 1, 2, \ldots\ldots 24 \\ \varnothing_{on},\ if\ t \in T_{on} \end{cases}$$ ……………(3)

$f2 = \min(TET_{customer}) = \min \sum_{t=1}^{24} \sum_{i=1}^{N} P^t i \varnothing^t$ ………………………(4)

where C_{cap} is the capital cost, $C_{maintenance}$ is the cost involved in maintenance, $\varnothing^t$ is the electricity price at time 't', $\varnothing_{off}$, $\varnothing_{on}$, and $\varnothing_{mid}$ are the price during off-peak (T_{off}), on-peak (T_{on}), and mid-peak (T_{mid}) hours, respectively. 'N' indicates the number of sources available for dispatch and P t i is the consumed power by the consumer 'i' at time horizon 't'. The problem formulation for minimizing the consumer's tariff is represented in Equation (4). For achieving the objectives, the loads on the system are effectively clustered into essential (EL) and non-essential loads (NEL) [10] by considering all the loads as residential loads as they are sharing 25% of load demand on the system.

Total load demand, TL = EL + NEL ……………………(5)

NEL = W1L1 + W2L2 + W3L3 ………………………(6)

Allocation of priorities to the non-essential loads or curtailable loads in such a way that there should not be any compromise in customer comforts and lifestyle. L1 Air conditioners, heating loads , L2 Washing machines , L3 EV's. L1, L2, and L3 are the non-essential loads and the order of priority based on importance is L1 > L2 > L3. The higher degree of charging flexibility associated with EVs makes it less prioritized when compared to the other loads in the MG. Therefore, to represent the importance of each load according to its priority, the weights added to the loads should be of different values, where, W1 = 0.66, W2 = 0.33, W3 = 0.13 such that all the loads should be met on the same day with some shift in time without violating the customer's satisfaction.

Subjected to the following constraints:

$$\sum_{n=1}^{N} P_{(n,t)}^{gen} = \sum_{l=1}^{L} P_{(l,t)}^{dem} - \sum_{s=1}^{S} P_{(s,t,i)}^{shift} + \sum_{s=1}^{S} P_{(s,i,t)}^{shift}$$ …………………(7)

The energy recovered during peak load is shifted or re-distributed to the other time horizons where the electricity price is low. Total energy curtailed has been re-distributed to other time horizons where electricity price is low. Therefore, the total area before curtailment and after curtailment becomes identical.

The generation should meet the load demand before and after shifting. The above Equation (7) represents the equality constraint, i.e., energy balance equation. Equation (8) shows the simplified version of the energy balance equation, where the difference between generation (by all the 'N' generators) and load demand (at all the 'L' loads) on the system should be dynamically balanced throughout the considered period, i.e., 24 h. to avoid any frequency drops. The response in loads can be modelled as an ideally flexible negative generation.

$$\sum_{n=1}^{N} P_{(n,t)}^{gen} - \sum_{l=1}^{L} P_{(l,t)}^{dem} = 0 \quad \forall\ T\ \in 1, 2, \ldots\ldots 24$$
$$\sum_{s=1}^{S} P_{DR(s,t,i)}^{max\ shift} \leq 110\ \%(P_{base}) \qquad \forall\ s\ \in 1, 2, \ldots\ldots S$$ ………………….(8)

$P^{shift}_{(t,i)}$ is the amount of load that has been shifted from 't' to 'i' and $P^{shift}_{(s,i,t)}$ is the amount of load that has been shifted from 'i' to 't $P^{dem}_{(l,t)}$ is the amount of load demand and $P^{gen}_{(n,t)}$ is the total generated power 'T' represents time in h and 'S' represents number of shifting intervals. The generator limits should not be violated while solving DR programs. The increased percentage of load shift by DR programs creates local peaks which occur due to rebound or payback phenomenon [17], at the non-peak hours. Here, Pbase is considered an average load on the system. The maximum limit on the amount of load shift depends on the shape of load duration curves. The maximum allowable load shift by using DR programs for this considered system should be 110% of base load power. This constraint is included in order to avoid payback effect or rebound effect. The operational cost of the MG also changes because of the load recovery. Further, the system marginal price (SMP) depends on the incremental fuel cost of the marginal generator. Hence, the SMP increases as the demand on the system increases.

$P_{base} = avg \sum_{t=1}^{24} P_L$ ……………………(9) , $P_{min} \leq P_t \leq P_{max}$

P^{Diesel}_{size} = max (dispatched energy by that generator in 24 hours), $EC_{MG\ with\ DR} \leq EC_{MG\ without\ DR}$ Optimal sizing of DGs without considering the impact of uncertainty is proposed. $EC_{MG\ with\ DR} \leq EC_{MG\ without\ DR}$ are the emission costs of MG with DR and without DR program, the total load demand on the system during 24 h. P_{min}, P_{max} are the minimum and maximum limits on generated power P_t from a generator 't'. Aggregated load demand is calculated based on the following Equation (10).

$P_{agg} = 1/T \sum_{t=1}^{24} P_t$ ……………………..(10)

$$LF=\frac{P_{agg}}{P_{L,}\max} \quad \text{……..……………………..……..(11)}$$

where Pagg is average of aggregated load demand, LF is the load factor of the MG, and PL,max is the peak load demand that is occurring on the system over 24 h.

3. PROPOSED METHODOLOGY

The solution methodology for reducing the total cost of the system is represented as follows:

• Read the load data, electricity price in each hour, generator data such as the minimum and maximum capacity, operating costs, and maintenance cost of each generator.
• Analyze the load profile and check whether the peak load is occurring at a high electricity price zone or not.
• As the total load on the system is considered as residential loads, cluster them as depicted in Equation (8), based on their priority without sacrificing the customer's satisfaction and lifestyle.
• If yes, shift a part of non-essential loads from the peak-occurring instant to the nonpeak zone. Therefore, cluster the loads on the basis of an order of priority and based on electricity price, the clustered loads are allocated or dispatched at a particular time instant where the electricity price is low. Priority is added by giving large weight to the highest priority load. If the load on the system is less than the average of the aggregated load, no need to cluster. Shift a part of the peak load to those intervals where the available load is less than the average aggregated load.
• There should be an upper limit imposed on the amount of load shift on the system to overcome the rebound effect, which is represented in Equation (8).
• If yes, shift the loads to another time horizon. If no, size the sources, i.e., the sizes of WT, PV, and diesel generators that have to be installed to supply the available load demand in the area without considering the impact of uncertainty based on the peak load demand. Moreover, a portion of generator capacity allocated for any further increment on load demand is represented in Equation (12). The total capacity of generators installed is the sum of all the DGs capacity

$$P_{size}^{DGs} = x\ \%\ (P_{size}^{MT} + P_{size}^{Diesel} + P_{size}^{Renewales}) \quad \text{……………..(12)}$$

• Calculate the capital cost, installation cost, and maintenance cost of each generator by using Table 8.

$$TC = \sum_{S=1}^{n} C_{PV}S_{pv} + C_{WT}S_{WT} + C_{diesel}S_{diesel} \quad \text{……………..(13)}$$

• CPV, CWT, and Cdiesel are the total costs including capital and installation costs of PV, WT, and diesel. SPV, SWT, and Sdiesel are the sizes of various sources yielded from the simulations.
• Dispatch or schedule the load on the available generators that are committed to supply and calculate the tariff of the consumer by using Equation (4).
• Calculate the load factor of the MG by using Equation (11). As the amount of load shift increases, the load curve becomes more uniform thereby improving the load factor.

Table 1. Various costs and lifetime of sources involved in installing the MG.

Source Type	Capital Cost ($/kW)	Fixed Maintenance Cost ($/kW)	Life (Years)
WT	1000	15	20
PV	1300	30.330	20
DG	800	0.012	15
MT	850	2000	15

Figure 2 shows the proposed methodology for achieving the optimal total cost of installation and optimal consumer tariff.

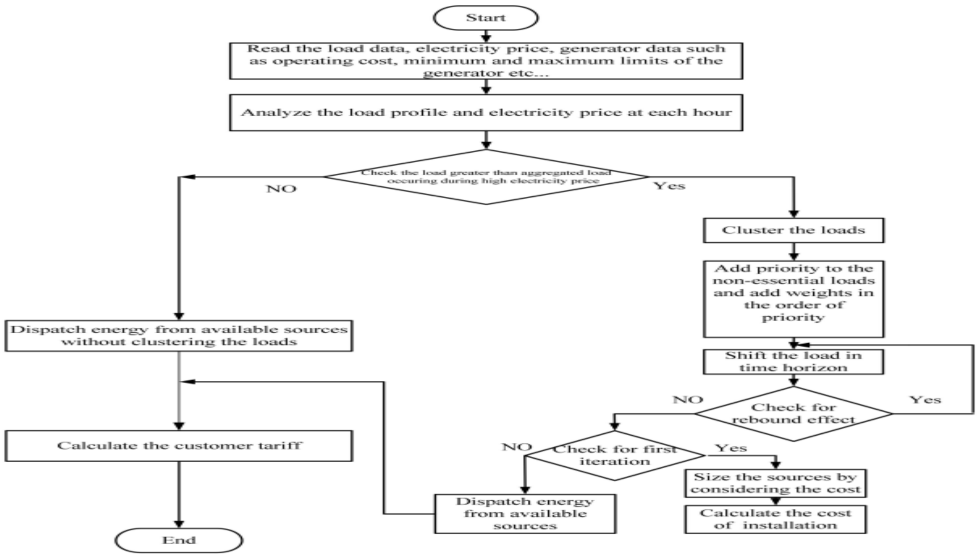

Figure 2. Methodology for analysing the impact of load clustering on DGs sizing and tariff.

4. RESULTS AND DISCUSSIONS

A test case has been considered to assess the influence of DR programs on optimal sizing of DGs and on the consumer's tariff. The IEEE-34 bus system is considered whose average load demand is 466.5 kW and the peak demand occurring on the system is 830.3 kW. The case studies are considered simulated with a 24-h load profile and the TOU tariff is taken into consideration. In general, among all the available price-based tariffs, TOU tariff is a simple one, easy to understand, and most customers show interest in this type of tariff.

For the considered test system, the customers are charged with a time of use (TOU) tariff where the hours in a day are clustered into peak, off-peak, and moderate peak hours, and the price is fixed. The prices are fixed DA, therefore, there is no ambiguity to the customer to enter into DR programs. Figure 3 shows the variation of DA electricity price and time. The electricity price is high from hours 10:00 to 21:00 and the peak load occurring zone is also at the same time; this results in huge customer bills. One way is to curtail the loads during peak hours to control the tariff where customers' load demand is not met. Another way is to shift the load demand from the peak load time horizon to off-peak hours. Figure 4 shows the load demand for the three cases considered. Executing DR strategies will benefit not only customers but also the suppliers too. Three cases have been considered, i.e., no penetration of ILs and 5% and 10% penetration of ILs, to analyze the impact of DR programs on consumer electricity bills and load factor. The load has shifted on the time horizon and the total demand on the system per day remains the same. Figure 18 shows the different levels of penetration of loads, i.e., 0%, 5%, and 10%.

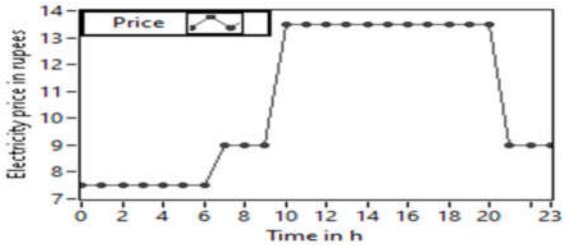

Figure 3. Time of use pricing.

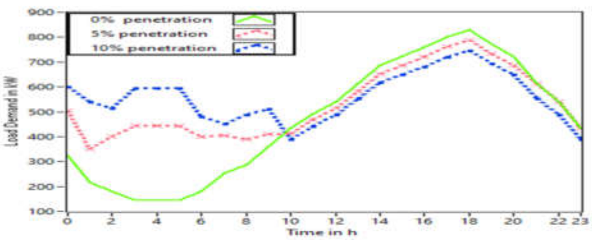

Figure 4. Load demand for three cases considered.

Depending on the objective function and the constraints considered the structure of search space changes. Therefore, to avoid this, we considered three scenarios, namely 0% penetration, 5% penetration, and 10% penetration. The algorithm is valid for all the considered scenarios even though the constraints change.

A local peak is created in the load demand curve at non-peak hour instant with a demand of 600 kW. In fact, the load demand before publishing DA tariff is 300 kW at that instant. This occurrence of local peaks at low price time horizon is considered as the rebound effect. If all the utilities supply this local peak demand, the generating companies will run in loss. Further, the emissions increase due to turning on of inefficient generators. To overcome the occurrence of the rebound effect, here, the maximum allowable load shift by using DR programs should be 110% of base load power. Hence, for the load profile considered, the average load is 466.5 kW and the maximum load that can be allowed during the non-peak hour should be less than 515 kW in the beginning hours where electricity price is minimal. Hence, ISO is responsible for maintaining the load profile within the specified limits.

4.1. Influence of DR Strategy on Optimal Sizing of DGs

The peak load on the system occurs occasionally and the generation and load demand balance should be met. The sizing of DGs will be based on the peak load that has to be supplied by the grid at any instant. Moreover, there is no need for installing new sources for supplying the occasional load. Therefore, this section investigates the impact of DR strategy in deciding the optimal capacity of

DGs. It has been said that the DR program will reduce the peak demand on the system which obviously reduces the capacity of the individual generators. The lower and upper limits on the decision variables are set as [0, 500] for all the generators considered. The inputs are initialized to the algorithm; it will yield the optimal sizing of each DG, capital cost, installation cost, and total cost of each DG for the proposed size. As seen from Figure 5 and from Table 2, if the penetration of non-critical loads or flexible loads increases, then the size and cost of deploying the DGs get reduced.

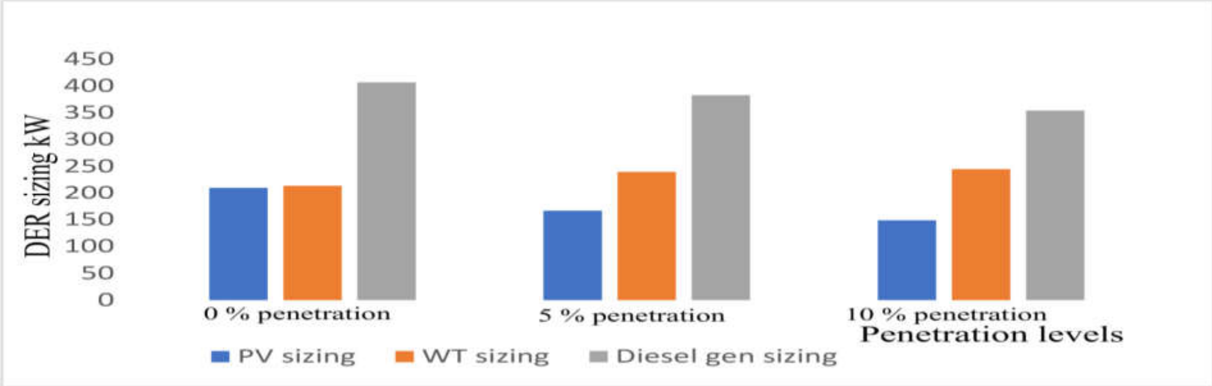

Figure 5. Sizing of sources without considering the uncertainty in RESs.

Table 2. Capital cost involved in various sources for the percentage of ILs penetration.

Percentage of ILs Penetration	Capital Cost of PV $/Day	Capital Cost of WT $/Day	Capital Cost of DG $/Day	Total Cost of MG $/Day
0%	279,374.621	216,914.635	325,225.678	821,514.900
5%	221,426.776	243,299.560	306,113.391	770,839.700
10%	196,888.840	248,550.155	283,033.045	728,472.000

4.2. Effect of DR Strategy on Consumer Electricity Bill and on Load Factor

The demonstrated work relates to the optimization of various costs, explicitly capital cost [18], installation cost, operational cost, and consumer tariff. To maintain the reliability in a heavily routed line, the ISOs basically charge more compared to the other prices. Under this scheme, the customers will get incentives for shifting [19] their loads to non-peak hours or curtailing their loads. This program is event-based, its fundamental focus is to maintain reliability in the MG. Dynamic pricing techniques alone may not fetch the feasible results as proposed in [11].

Figure 6 depicts that while increasing the level of penetration of the customer electricity bill gets reduced and the load factor gets increased. The reduction in customer bill from 0% penetration of ILs to the 5% penetration of ILs is 3709.26 Rs/day and from 0% to 10%, the reduction is 6059.025 Rs/day. Table 3 represents the reduction of electricity price and improvement in load factor for the system considered. Further, it also depicts that the reduction in peak demand from 830.300 kW to 747.270 kW from 0% penetration to 10% penetration, where the load factor is increased from 0.561957 to 0.624397.

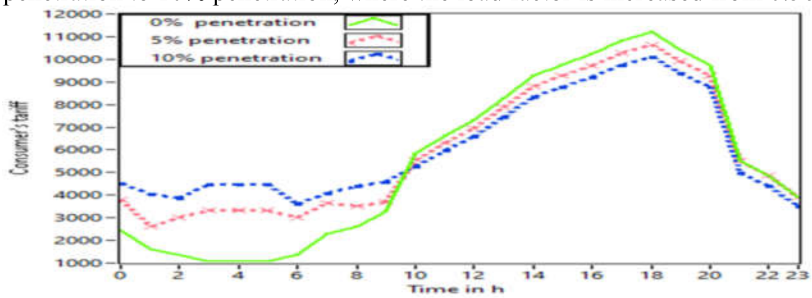

Figure 6. Electricity price of consumers for three cases considered.

Table 3. Comparison of peak demands, electricity price, and load factor with penetration of ILs.

S.No.	Penetration of ILs in %	Peak Value of Load, kW	Electricity Price, Rs/Day	Load Factor
1	0%	830.300	131,952.7	0.561957
2	5%	788.785	128,243.5	0.591540
3	10%	747.270	125,893.7	0.624397

As the level of penetration increases, the load profile becomes flat and the electricity tariff gets reduced and is clearly depicted in Figure 4 at 00:00 to 08:00 a.m. However, there is a chance of the local peak occurring in case 3 where 10% penetration of flexible or non-critical loads allowed it to penetrate the MG system. As a greater number of customers participate in the DR program, the level of peak increases. Therefore, unjustified shifting of a portion of the load from global peak to the off-peak should be avoided to reduce the burden on the power systems. Hence, there should be an upper limit on the amount of load shift. ISO should focus not only on possible reduction of consumer tariff but also ensure to overcome the rebound effect.

CONCLUSIONS

A test system with three scenarios considered, namely no penetration of ILs (i.e., 0% load shift), 5% penetration of ILs, and 10% penetration of ILs, showed total daily load demand of 11,198.2 kW and maximum peak on the system on an hourly basis is 830.3 kW. The capacity of DERs is a function of peak load occurring on the system and the system load factor is a function of uniformity of load curve. Therefore, with the reduction in peak demand on the system, the load curve gets more uniform which reduces the size of DERs and improves the load factor of the system which further reduces the customer tariff. The reduction in peak demand for the MG from 0% penetration to 5% penetration is 41.515 kW and from 0% penetration to 10% penetration is 83.03 kW and the reduction in the cost of installation of DGs is 50,675.21 $/day. A time of use pricing model is considered and the loads are clustered based on the prices at each interval. From the results, it is shown that the reduction in customer electricity tariff from 0% penetration to 5% penetration is 3709.26 Rs/day. The results show that, with the deployment of DR programs into the MG, there is a huge impact on the above-considered test systems.

REFERENCES

[1]. *Li, K.; Thompson, S.; Peng, J. Modelling and prediction of NOx emission in a coal-fired power generation plant. Control Eng. Pract.* ***2004****, 12, 707–723. [CrossRef]*

[2]. *Ahi, P.; Searcy, C. Assessing sustainability in the supply chain: A triple bottom line approach. Appl. Math. Model.* ***2015****, 39, 2882–2896. [CrossRef]*

[3]. *SanjeevaKumar RA,Kavya Prayaga, "A Weighted Sum of Multi-Objective Function based Reliability Analysis with the Integration of Distributed Generation",International Journal of Engineering and Advanced Technology(IJEAT),Volume-9 Issue-4,April 2020.*

[4]. *Kim, C.-Y.; Kim, C.-R.; Kim, D.-K.; Cho, S.-H. Analysis of Challenges Due to Changes in Net Load Curve in South Korea by Integrating DERs. Electronics* ***2020****, 9, 1310. [CrossRef]*

[5]. *Sanjeeva Kumar R A, Sudarshana Reddy H R and Ananthapadmanabha T, "Enhancement of Power Quality in Distribution System by Optimal Integration of Distributed Generators Using Hybrid Flower Pollination Algorithm", International Journal of Electrical Engineering & Technology, Volume 9, Issue 3, 9(3),2018, pp. 146–153*

[6]. *Mellouk, L.; Ghazi, M.; Aaroud, A.; Boulmalf, M.; Benhaddou, D.; Zine-Dine, K. Design and energy management optimization for hybrid renewable energy system- case study: Laayoune region. Renew. Energy* ***2019****, 139, 621–634. [CrossRef]*

[7]. *Aziz, A.; Tajuddin, M.; Adzman, M.; Ramli, M.; Mekhilef, S. Energy Management and Optimization of a PV/Diesel/Battery Hybrid Energy System Using a Combined Dispatch Strategy. Sustainability* ***2019****, 11, 683. [CrossRef]*
Sanjeeva Kumar R A, Sudarshana Reddy H R and Ananthapadmanabha T, "Multi-Objective Based Analytical Approach For Optimal Placement Of Distributed Generators In Power System", in Journal of Emerging Technologies and Innovative Research, Vol5, Issue 7, page no.605-609, July 2018,

[8]. *Shoeb, A.; Shafiullah, G. Renewable Energy Integrated Islanded Microgrid for Sustainable Irrigation—A Bangladesh Perspective. Energies 2018, 11, 1283. [CrossRef]*

[9]. *Siritoglou, P.; Oriti, G.; Van Bossuyt, D. Distributed Energy-Resource Design Method to Improve Energy Security in Critical Facilities. Energies 2021, 14, 2773. [CrossRef]*

[10]. *Sanjeeva Kumar R A, Sudarshana Reddy H R and Ananthapadmanabha T, "Analytical Approach for Optimal Placement of Distributed Generators in Power System", in International Journal of advent in research Technologies (IJRAT), July 2018, Volume 6, Issue 7.*

[11]. *Zhu, W.; Guo, J.; Zhao, G.; Zeng, B. Optimal Sizing of an Island Hybrid Microgrid Based on Improved Multi-Objective Grey Wolf Optimizer. Processes 2020, 8, 1581. [CrossRef]*

[12]. *Jalili, A.; Taheri, B. Optimal Sizing and Sitting of Distributed Generations in Power Distribution Networks Using Firefly Algorithm. Technol. Econ. Smart Grids Sustain. Energy 2020, 5, 1–14. [CrossRef]*

[13]. *R A Sanjeevkumar Sumit A Novel Generalised Topology of a Reduced Part Count Multilevel Inverter with Level Boosting Network to Improve the Quality of Supply Global Transitions Proceedings (2021), 10.1016/j.gltp.2021.08.019 ISSN 2666-285X, a Elsiver Publication.*

[14]. *Madahi, S.K.; Sari´c, A. Multi-Criteria Optimal Sizing and Allocation of Renewable and Non-Renewable Distributed Generation Resources at 63 kV/20 kV Substations. Energies 2020, 13, 5364. [CrossRef]*

[15]. *Yuan, R.; Li, T.; Deng, X.; Ye, J. Optimal Day-Ahead Scheduling of a Smart Distribution Grid Considering Reactive Power Capability of Distributed Generation. Energies 2016, 9, 311. [CrossRef]*

[16]. *S. Trimukhe, R A Sanjeevkumar Power Quality Improvement in Grid Connected PV System using Reduced Part Count Multilevel Inverter by Performing Power Balance 2021 IEEE PES/IAS PowerAfrica (2021), pp. 1-5, 10.1109/PowerAfrica52236.2021.9543295*

[17]. *Galván, L.; Navarro, J.M.; Galván, E.; Carrasco, J.M.; Alcántara, A. Optimal Scheduling of Energy Storage Using a New Priority-Based Smart Grid Control Method. Energies 2019, 12, 579. [CrossRef]*

[18]. *Li, J.; Tan, Z.; Ren, Z.; Yang, J.; Yu, X. A Two-Stage Optimal Scheduling Model of Microgrid Based on Chance-Constrained Programming in Spot Markets. Processes 2020, 8, 107. [CrossRef]*

[19]. *Sumit Trimukhe , Sanjeevkumar R A , Grid interconnected H-bridge Mul tilevel Inverter for renewable power applications using Repeating Units and Level Boosting Network, Global Transitions Proceedings (2021)ISSN 2666-285X,* https://doi.org/10.1016/j.gltp.2021.10.005. *a Elsiver Publication.*

[20]. *Wang, J.; Li, K.-J.; Javid, Z.; Sun, Y. Distributed Optimal Coordinated Operation for Distribution System with the Integration of Residential Microgrids. Appl. Sci. 2019, 9, 2136. [CrossRef]*

[21]. *Lu, C.; Xu, H.; Pan, X.; Song, J. Optimal Sizing and Control of Battery Energy Storage System for Peak Load Shaving. Energies 2014, 7, 8396–8410. [CrossRef]*

[22]. *Sanjeevkumar, R. A., & Kavya, Prayaga. (2021, August). Optimization of DG Placement for Demand Side Management in Distribution System with Demand Response. In 2021 IEEE PES/IAS PowerAfrica (pp. 1-5). IEEE. doi: 10.1109/PowerAfrica52236.2021.9543419.*

[23]. *Karunarathne, E.; Pasupuleti, J.; Ekanayake, J.; Almeida, D. Optimal Placement and Sizing of DGs in Distribution Networks Using MLPSO Algorithm. Energies 2020, 13, 6185. [CrossRef]*

[24]. *Kavya prayaga and Sanjeeva Kumar R A "power quality analysis of distribution system using hybrid intelligent algorithm by optimal integration of dg's" Journal of Emerging Technologies and Innovative Research, Vol 06, Issue 5, May 2019,*