ASSESSMENT OF DISTRIBUTED GENERATION CAPACITY MIXTURE FOR HYBRID BENEFITS

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ABSTRACT

The distributed generation (DG) mixture in an active distribution network can provide different levels of network benefits and benefits external to the network. This paper investigates this problem in detail and proposes an approach to assess the DG mixture for hybrid benefits through the sequential simulation of optimized samples. A case study is performed incorporating Wind and PV generation as intermittent DG, diesels, their life-cycle costs (LCCs), and contribution to greenhouse-gas (GHG) abatement. Results suggest that specific operating conditions in a network can dominate the DG mixture and deliver the combined benefits. Wind and diesel hybrid operation can be the most beneficial DG mixture in an active distribution network compared to any other DG combination with current costing structure.

INTRODUCTION

Increased integration of intermittent distributed generation (DG) into active distribution networks can potentially reduce the need for fossil-fuel generation. However, such integration does not necessarily increase benefits because of the congestion and constraint violations potentially arise from them. The benefits of intermittent DG should be assessed within the context of combined benefits that are associated with benefits internal and external to a network in balancing the environmental sustainability with efficient, economic, and secure supply of electricity to consumers.

The internal benefits include the benefits offered by DG for the efficient, secure, and economic operation of a network and their extensions to end users. The external benefits include the potential reduction in greenhouse-gas emissions into the environment. The internal benefits are generally quantified by incorporating life-cycle cost (LCC) of assets to leverage life cycle of equipment associated effects. Life cycle costing is a process to determine the sum of all the costs associated with an asset or part thereof, including acquisition, installation, operation and maintenance, refurbishment, and disposal costs. Greenhouse-gases (GHGs) are those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorbs and emits radiation of specific wavelengths within the spectrum of thermal infrared radiation emitted by the Earth's surface, the atmosphere itself, and by clouds. [1-5]

Increased integration of renewable power generation into distribution networks requires an adequate evaluation of their contributions in order to assess the environmental impacts, network impacts, and economics of the overall production and utilization lifespan, including the construction and operating stages of renewable plants. [6, 7]

Distributed generation capacity and related impacts have been evaluated in many contexts and the published literature evidences them. Effect of DG capacity with strict voltage limits is explored in [8]. Taking into account into account thermal and voltage limit constraints, the reference [9] proposes an approach to calculate the available headroom in a network with DG. Differed distribution network capacity reinforcement with DG is investigated in [10]. Reference [11] explores the impacts on the installed capacity of DG with the distance relays in an active distribution network. Network reinforcement to maximize the DG capacity is explored in [12]. Reference [13] proposes a method to locate and size DG by minimising the power losses. Capacity credits due to DGs are investigated in [14] by the application of Monte Carlo Simulation. The intermittent DG capacity in the presence of active network management controls is assessed in [15, 16].

This paper proposes a hybrid approach to assess the DG capacity mixture taking into account network benefits and benefits external to the network. Network benefits are assessed by minimizing the cost to offer a reduced tariff to the electricity consumers. Life cycle costs of generation assets are also incorporated for assessing the DG mixture that results the minimum cost through network internal benefits. External benefits are quantified through the reduction in volumes of greenhouse-gas emissions. Both types of benefits are compiled by the application of carbon tax provision into the reduction in greenhouse-gas emission. The entire approach drives through the sequential simulation of optimised samples capturing intermittent effects of DG and demand level variations at each customer sector in an active distribution network environment.

HYBRID APPROACH

Figure 1 shows the main steps of the hybrid approach proposed to determine the DG mixture taking into account network benefits and benefits external to the network. The internal benefits are quantified through LCC of generation assets and cost of generation of electricity by them. The external benefits are quantified through GHG emissions taking into account the project life-span. The approach considers diesel units are also as distributed generators that can buffer intermittent effects of renewable power generation to an extent.

The hybrid approach is divided into four phases for the simplicity of explanations and to calculate DG mixture references. They are Phase A, Phase B, Phase C, and Phase D. Phase A, which is the base step, is used to model the base network with voltage and thermal limit constraints, and perform A/C power flow analysis to determine the network health. Then, DG types and total capacities based on their geographical location, network transport capacity at the deep end, and resource availability are given in addition to the costing data. Demand level variations and load growth of sector customers are also modelled at this stage following the convergence of the load flow solution. Next, the total costs are minimized for the sample operating condition. Samples are created to capture time-related variations of demand. Total costs are calculated using the capital costs of required plants, start-up costs, and operating costs of them to generate electricity. Capital costs at this phase are calculated using the investment cost of individual generating units without incorporating the life-cycle cost components of them. The operating costs are calculated using cost of power generation resulting through the minimal energy losses and minimum use of fossil-fuel generation. The DG mixture is then calculated using the sequential simulation of optimized samples. The maximum DG capacity that results in minimum total costs by satisfying all operating conditions and constraints is considered as the base DG capacity of the network.

During the sequential simulation, any violated operating conditions splits into two groups. The first group considers a penalty cost for violating the operating limits that in turn added to the yearly running cost of the selected DG mixture. The second group discards entire DG combination of the sample, and assessment continues with remaining combinations of DG.

In addition, diesel generators of the network are operated only within the economic region of their operation or in other words, diesel units are operated from 40% to 100% of their rated capacities to minimize inefficiency of the units. At each operating condition, the diesel generator loading level is determined and if any unit output is below 40% limit, then the feasibility is checked to reduce the output of the other diesel units that are loaded more than 40%. If this attempt is infeasible for the operating condition of the sample with all the network resources, then the corresponding unit is forced to shut down and the ability of the remaining generating units to operate the network as healthy is determined. The load shedding is incorporated; however, it is the least priority option, and it is executed based on the availability of flexible loads (e.g. micro grid type loads) or loads contracted for the flexibility.

In Phase B, maximum DG mixture that gives the minimum total costs is determined based on the intermittent DG characteristics and added objective of achieving the minimal cost of energy losses from the system. The cost of energy losses for the system is calculated by assuming that all the energy losses in the network are supplied by the diesel and other conventional generators of the network. In other words, conventional generators are assumed to generate an extra power to meet the power loses of the network. Thus, the approach minimises cost of conventional generation to reflect the minimal energy losses. This assumption provides the worst-case scenario because of the conventional generators have the highest unit costs of supplying the energy in energy transportation.

In phase C, LCC of generation assets in place of capital cost of them is applied to determine the DG capacity mixture.

In Phase D, the same procedure as in Phase C is applied by additionally incorporating the greenhouse-gas abatement provision of generation assets. Thus, the approach also minimizes the GHG emission level to determine the DG capacity mixture.

Then, the carbon tax values are applied the reduction of greenhouse-gas tonnes, and the DG mixture for the network is calculated by integrating the costs' results through network internal benefits and the external benefits.

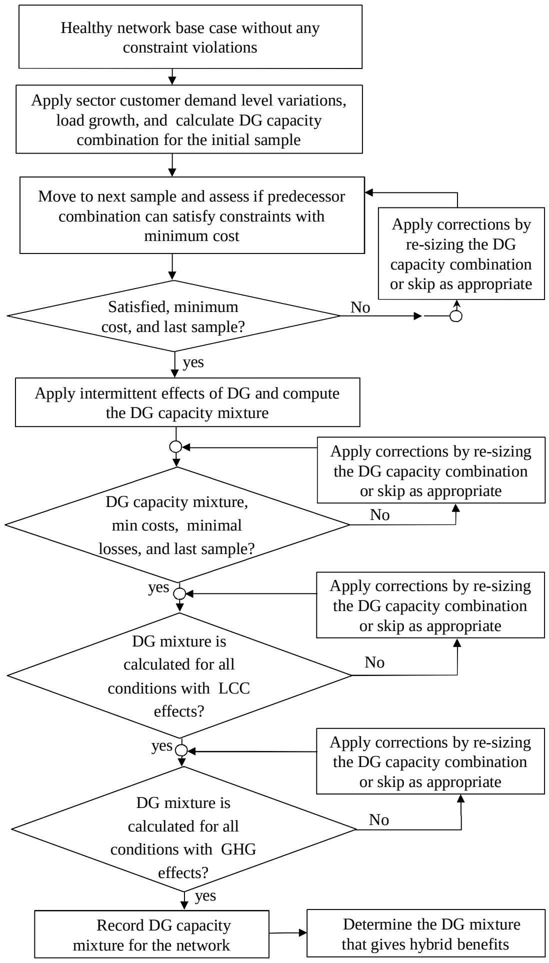

Figure 1 Overview of DG mixture assessment using the hybrid approach

The problem solved at a sample operating condition to calculate DG mixture becomes the following.

Min $$F = \sum_{i \in NG} C_i(LCC_i) + \sum_{i \in NG} C_i(E_i) + C_{c-tax} \sum_{i \in NG} C_i(GHGT) \quad (1)$$

Subjected to:

$$P_i(V,\theta) = P_{G_i} - P_{D_i} \quad (2)$$

$$Q_i(V,\theta) = Q_{G_i} - Q_{D_i} \quad (3)$$

$$\left|S_{ij}\right| \le S_{ij}^{\max} \quad (4)$$

$$V_i^{\min} \le V_i \le V_i^{\max} \quad (5)$$

$$P_{G_i}^{\min} \le P_{G_i}(V,\theta) \le P_{G_i}^{\max} \quad (6)$$

$$Q_{G_i}^{\min} \le Q_{G_i}(V,\theta) \le Q_{G_i}^{\max} \qquad (7)$$

Where, $C_i(LCC_i)$ = life cycle cost of generators, $C_i(E_i)$ = cost of energy generation, $C_i(GHGT_i)$ = greenhouse gas tonnes, C_{c-tax} = carbon tax, P_i = real power injection at bus i, Q_i = reactive power injection at bus i, P_{G_i} = real power output of the generator connecting to bus i, Q_{G_i} = the reactive power output of the generator connecting to bus i, P_{D_i} = the real power load connecting to bus i, Q_{D_i} = the reactive power connecting to bus i, V_i = voltage magnitude at bus i, V = voltage, θ = angle, S_{ij} = power flow at a line from bus i to bus j, NG = number of generators, subscripts "min" and "max" give the lower and upper limits of constraints.

CASE STUDIES

Case studies are performed incorporating a network with a mix of radial and meshed feeders spanning over three zones. The first zone is a 13 bus radial configuration which has active and reactive power loads of 12 MW and 3 MVAr respectively. Its nominal operating voltages are from 0.69 kV to 132kV. The first zone demand can be supplied by a wind farm and a diesel plant. The second zone is a 27-bus single and double line configuration, which has active and reactive power loads of 18MW and 2MVAr respectively. Its nominal operating voltages are from 0.69 kV to 132kV. The demand can be supplied through a wind farm and a diesel plant. The third zone is a 12 bus radial feeder configuration which has active and reactive power loads of 14 MW and 3 MVAr respectively. Its nominal operating voltage varies from 11kV to 132kV. The demand can be supplied through a PV system and a diesel plant.

Annual load growth is not taken into account for the case studies; however, time series of sector customer demand variations at each hour are modeled together with annual wind and PV power generation profiles. The project life is considered as 25 years. A depreciation rate of 7 % is used to calculate the net present value of the costs at each year. Greenhouse gas coefficient of 1.38 kg CO2-e/kWh is considered during the assessment. Case study considered weekly samples spanning over a year.

Cost of DG combinations excluding GHG provision

Figure 2 shows the total costs of DG combinations of wind, PV, and diesel generators excluding GHG emission provision corresponding to weeks of a year. The results suggest that the optimum DG mixture can be determined by the 47th week operating condition if the GHG reduction benefits are excluded from the assessment. The DG mixture corresponding to week 47 has a greater power generation from wind and PV and less power generation from diesels. This scenario also meets the annual demand of the network without violating constraints and offers the lowest total costs.

GHG emission of DG combinations

Figure 3 shows the greenhouse-gas emission in an equivalent of CO_2 weight in tonnes against weekly scenarios given in Figure 2. The results suggest that the DG unit combination corresponding to 29th week configuration has the least GHG emission. Therefore, the operating condition at 29th week can be considered as the scenario that can determine the most beneficial DG unit combination with regard to benefits external to the network.

Ranking of costs of external and internal benefits

Figure 4 shows the costs ranks with internal benefits. The lowest-cost rank of internal benefits results at the operating condition of 47th week. Figure 5 shows external benefit cost ranks corresponding to the weekly combinations. The lowest rank is resulted at the operating condition of 29th week.

Combined benefits

The costing ranks by integrating internal and external benefits suggested that the most beneficial DG unit combination results at 41st week operating condition; however, it is not the best combination if either cost of internal benefit or cost of external benefits is decoupled. Extended studies also suggested that the DG unit combination results through the week 41st operating condition had a lower load share by diesel units and much higher load share by wind units. This results the lowest cost of external benefit rank for the DG unit combination corresponding to the week even though the cost of internal benefit rank is lower than the DG unit combination that results through the 47th week operating condition.

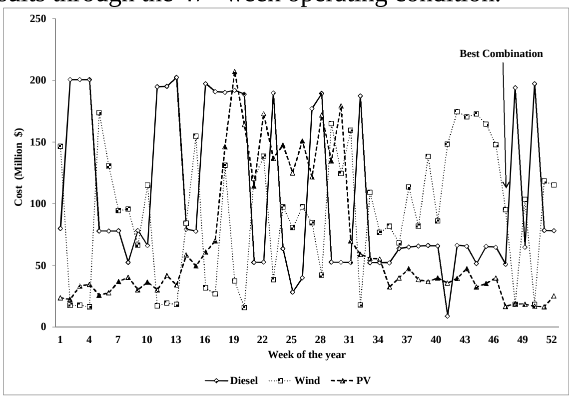

Figure 2 Costs of DG combinations excluding GHG resulting cost

Extended studies with internal benefits

Case studies extended to assess the variation in total costs of internal benefits of the system when combinations of generation technologies are varied to supply the same load demand relaxing the resource availability. In these scenarios, the most economical combination is at the hybrid system with diesel and wind units. This combination offers 12% less cost than the combination of diesel, wind, and PV. The results further suggest that the wind/diesel operation is 22% economical than that of PV/diesel operation for the particular network.

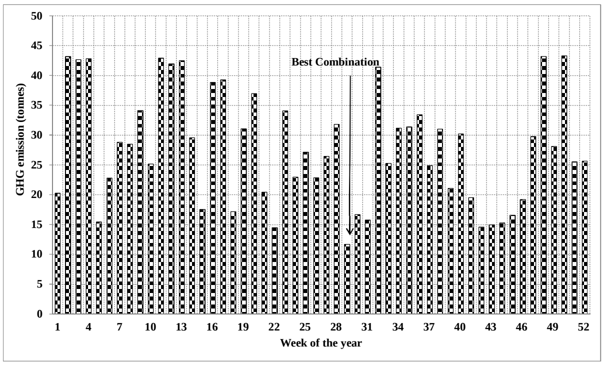

Figure 3 GHG emission of DG in Figure 2

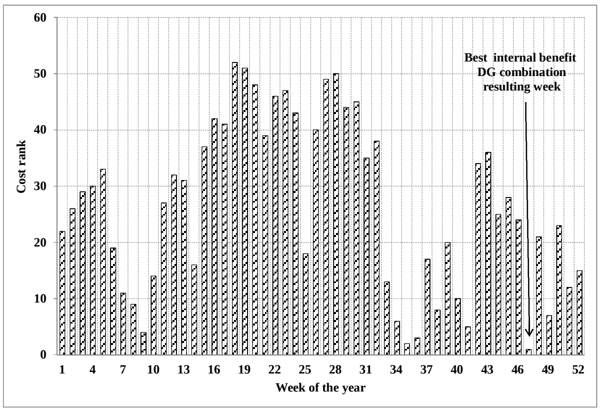

Figure 4 Internal cost ranks based on internal benefit provision

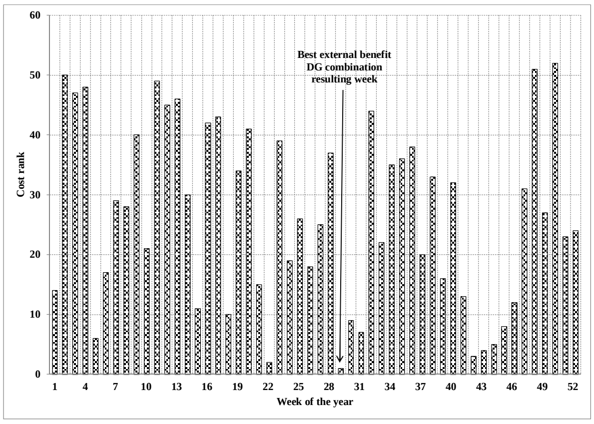

Figure 5 External cost ranks based on external benefit provision

CONCLUSIONS

A hybrid approach is proposed for the assessment of DG mixture that provides global benefits taking into account the cost of generating electricity, LCC of assets, and GHG abatement effects. Case studies suggest that DG types and capacities in an active distribution network can also be determined by specific operating conditions on the network. The internal benefit based DG mixture determining operating condition differs from the external benefit based DG mixture determining operating condition. The investigations also suggested that wind and diesel unit hybrid operation costs less than the combined operation of diesel, wind, and PV units for the particular network model. The wind-diesel operation is more economical than that of PV-diesel operation for the same operating conditions. Optimal integration of DG into active distribution networks is vital for balancing the technical merits and reduction in greenhouse-gas emissions. In that context, the proposed approach can be used for benchmarking distribution networks against hybrid benefits.

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