A Control Architecture for Optimal Power Sharing between Interconnected Microgrids

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Abstract—Energy management system (EMS) is responsible for generation scheduling and power dispatch of microgrids (MGs). When many MGs are interconnected, it is preferable to exchange power among MGs in such a manner so as to minimize their operating cost while reducing dependency on the main grid. The paper proposes a cost driven power sharing scheme combined with a more realistic EMS. These are implemented in two layers which communicate with each other to optimize MG operation. Simulation results demonstrate the benefits of the proposed approach.

I. INTRODUCTION

Microgrids (MGs) are small-scale electrical grids comprising several distributed energy resources and energy storage systems (ESSs). The ability to integrate high share of renewable energy sources (RES) motivates research towards the implementation of MGs. ESS is mainly used to shave load peaks and absorb possible power fluctuations due to the intermittent nature of RES [1]. Energy management system (EMS) facilitates the economic operation of MGs through the efficient utilization of RES and ESS to reduce the operating cost of fuel-based dispatchable sources such as diesel generators. In general, MGs are expected to be self-dependent in terms of energy requirement. However, depending on the application, MGs can be operated either in grid-connected mode or standalone mode. Specifically, neighboring MGs can be interconnected to share power between themselves as necessary so as to optimize operational benefits. Centralized EMS mainly targets islanded MGs whereas decentralized control schemes are more attractive for grid-connected or interconnected MG applications [1]. This paper proposes a multi-period decentralized two-layer control scheme to optimize resource utilization among interconnected MGs based on nodal pricing.

Energy management (EM) is a complex task which determines the optimal generator schedule and power dispatch of the MG for each time interval. The EM problem considers operational characteristics of power sources, power flow equations and system security constraints in its formulation. Thus, a complete EM problem formulation would combine unit commitment (UC) and optimal power flow (OPF) problems [2]. In general, it turns out to be a mixed-integer nonlinear (nonconvex) problem which is NP-hard. Model Predictive Control (MPC) framework has recently gained popularity in the context of developing EM formulations for MGs. Due to its complexity, the EM problem is normally formulated by neglecting system security constraints and power losses. In such cases, it turns out to be a mixed-integer quadratic program (MIQP) which is efficiently solved in the MPC framework using commercial solvers like CPLEX, MOSEK etc. The applicability of such results is sometimes questionable as they may violate network constraints. Also, power losses are sometimes significant in the context of MGs which may render the power dispatch impractical.

Distributed computations hold a lot of promise in the context of reducing computational time. In [3] and [4], centralized cooperative schemes are proposed for standalone MGs. The UC problem is formulated based on the power nodes framework and is solved in conjunction with the OPF problem so as to adjust generator set-points to satisfy power flow equations. In [3], the approach is extended to large-scale networks by creating sub-problems which are solved in a distributed fashion. In [5], a method is developed to coordinate storage and intermittent resources in multiple control areas based on optimality condition decomposition. In [6], the power sharing problem among interconnected MGs is addressed using a centralized controller. An MPC based algorithm is used to compute the power sharing and energy storage scheduling considering forecasted energy prices of the main grid and other MGs. The authors do not consider dispatchable sources such as diesel generators (DGs) which are common in remote MGs. Moreover, the problem becomes more complex to formulate with the presence of dispatchable sources.

In this work, we focus on a comprehensive realistic problem formulation which includes DGs, ESS, wind and solar PV power plants, and power exchange with main grid and neighboring MGs. A two-stage decentralized EMS architecture is implemented to decide the optimal generator schedule and power dispatch. A novel cost driven power sharing scheme is developed as a tertiary layer, which couples with the EMS to realize the requirements/preferences of each MG in terms of power exchange.

II. ELECTRICAL SYSTEM MODEL

The system in this study consists of several MGs interconnected with each other and the main grid. A particular MG may contain several DGs, wind power plants, solar PV power plants and ESS as power generation sources. DGs are
controllable sources with a quadratic fuel cost function of real power dispatch. A DG’s power output is constrained by real and reactive power output bounds, ramp rate constraints, minimum uptime and downtime constraints [2]. The cost function for DGs is expressed as follows:

\[ C^t_{DG,g} = SU^t_g d_g + U^t_g \left( a_g + b_g P^t_g + c_g \left( P^t_g \right)^2 \right) \] (1)

where \( DG \) is the set of DGs; \( g \in DG; a_g, b_g \) and \( c_g \) are the cost coefficients of the DGs; \( U^t_g \) is a binary variable which is 1 if the unit \( g \) is committed during hour \( t \) and \( SU^t_g \) is a binary variable which is 1 if the unit \( g \) is started up during hour \( t \); \( d_g \) represents the start-up cost for unit \( g \).

An ESS is considered to mitigate demand fluctuations and facilitate peak clipping (or valley filling) in a cost-effective manner. Moreover, we consider a realistic ESS model which includes intertemporal constraints for the state-of-charge (SOC) and a battery degradation cost to reflect the effect of charging and discharging on the cost of purchase [7]. The battery cost modelling is briefly presented below.

\[ SOC^{t+1}_i = SOC^t_i + \left( \eta_{c,i} P^t_{bc,i} - P^t_{bd,i}/\eta_{d,i} \right) / P_{1,E,i} \] (2)

\[ SOC^{min} \leq SOC^{t+1}_i \leq SOC^{max}_i \] (3)

\[ 0 \leq P^t_{bc,i} \leq P_{max}^{bc,i} \] (4)

\[ 0 \leq P^t_{bd,i} \leq P_{max}^{bd,i} \] (5)

The overall ESS cost function is expressed as follows:

\[ C^t_{ES,i} = \frac{I_i}{2 B_{cap,i} N_i} \left[ \frac{P^t_{bc,i}}{T_{bc,i}} + \frac{P^t_{bd,i}}{T_{bd,i}} \right] \] (6)

Here, \( ES \) is the set of ESSs; \( i \in ES; P^t_{bc,i} \) and \( P^t_{bd,i} \) are the charging and discharging powers respectively at hour \( t \); \( P_{1,E,i} \) is the power required by the ESS to charge 100% in 1 hour i.e. 1E rate. \( (\cdot)^{min} \) and \( (\cdot)^{max} \) represent the minimum and maximum bounds of the respective parameters respectively; \( N_i \) is the expected number of cycles before the ESS reaches its end of life; \( T_{bc,i} \) and \( T_{bd,i} \) are the average number of hours the battery charges and discharges in a day respectively; \( \eta_{c,i} \) and \( \eta_{d,i} \) are the charging and discharging efficiencies respectively; \( I_i \) is the cost of purchasing the ESS and \( B_{cap,i} \) is the capacity of the \( i^{th} \) ESS in kWh [7].

The thermal units and ESS are modelled using HYSDEL [8]. HYSDEL is based on the Mixed Logical Dynamical (MLD) modelling framework, described in [9]. Considering the hybrid nature of the scheduling problem, MLD provides a convenient framework to implement all relevant features of the microgrid [10]. More details can be found in [10] and [11].

III. MICROGRID HIERARCHICAL CONTROL SYSTEM

In a hierarchical control structure, multiple control layers are assigned to fulfill various operations and control tasks sufficiently in the MGs. The hierarchical control system ultimately aims at facilitating power transfer between the main grid and interconnected MGs effectively. The primary level in this structure is responsible for frequency control or power sharing within the MG according to droop settings. The secondary layer is called the energy management system (EMS). It schedules generation (sends commitment and dispatch commands) for optimal MG operation while considering load and RES generation forecasts, ESS SOC, DGs’ operational status etc. The tertiary layer examines the status of neighboring MGs and the main grid to coordinate the power sharing among them. These layers should be implemented with adequate separation in time to prevent possible interference [1]. The focus of this paper is on the secondary and tertiary layers.

A. Energy Management System Architecture

The proposed EMS architecture consists of two stages to optimize the total operating cost and the grid utilization of each MG. The EMS controller of each MG is operated separately to optimize its own operational cost. Another important outcome of the EMS controller is that it estimates how much power can be supplied to/demanded from neighbouring microgrids. The EMS is implemented under the following assumptions:

1) Power sharing between MGs and between the main grid and MGs is assumed to be deregulated i.e. it depends on market prices. The buyer MG (which demands power) does not have the flexibility to decide the price. It should buy the required power at the price offered by the seller MG (which supplies power) i.e. the nodal price at the seller MG.

2) The day-ahead buying and selling prices of the main grid at each point-of-common coupling are available. All MGs are assumed to be price takers in trading with main grid i.e. MGs should buy/sell energy from/to the main grid at pre-specified prices.

3) The day-ahead load demand profile and RES output forecasts is known with sufficient accuracy.

The complete operational cost optimization problem for a particular MG is formulated in two sequential stages (say problems A and B). Computations for each MG will be performed only by exchanging nodal prices and power deficit or surplus information. The two-stage EMS implementation is explained below.

1) MEC-based Cost Minimization: Stage one (problem A) is responsible for generation scheduling to satisfy active power demand in an optimal manner. Factors considered in the optimization include characteristics of DGs, characteristics of ESS, wind and solar day-ahead generation forecasts, nodal prices, power surplus or deficit of neighboring MGs, selling and buying prices of the main grid, day-ahead load forecast and network losses. The optimization problem is implemented in the MEC framework [10]. The objective is to schedule the generation to minimize the operating cost for the given time frame. The active power balance of the whole system and generator ramp rates will constrain the problem in addition to bounds on the DG and ESS generation. This UC problem is an MIQP problem which can be efficiently solved in polynomial time. The overall objective function and load balance constraint are as mentioned below. For \( i^{th} \) and \( j^{th} \) MGs; Let \( P^t_{MGp,i,j} \) and \( P^t_{MGs,i,j} \) are the power values that \( i^{th} \) MG would like to purchase from and supply to \( j^{th} \) MG.
respectively. However, these two are complimentary to each other i.e. $P_{MG,i,j}^t P_{MG,j,i}^t = 0$ to avoid bidirectional power flow in between two MGs at the same time instance.

Minimize the total operating cost ($TOC$) of $k^{th}$ MG:

$$\text{Min} \ TOC_k = \sum_t \sum_{i \in DG} C_{DG,i}^t + \sum_t \sum_{i \in ES} C_{ES,i}^t + \sum_t \left( \lambda_{MG,i}^t P_{MGp,k,i}^t - \lambda_{MG,k}^t P_{MGs,k,i}^t \right) + \sum_t \left( c_{gs}^t P_{gs}^t - c_{gs}^t P_{gs}^t \right)$$

(7)

Real power balance:

$$\sum_{i \in DG} P_i^t + \sum_{i \in MG \atop i \neq k} \sum_t \left( P_{MGp,k,i}^t - P_{MGs,k,i}^t \right) + P_{gs}^t - P_{gs}^t + \sum_{i \in ES} \sum_{i \in WG} P_{bd,i}^t - P_{bc,i}^t + \sum_{i \in PV} P_{w,i}^t + \sum_{i \in PV} P_{pv,i}^t = PD^t + P_{loss}^t$$

(8)

where $WG$ and $PV$ are the sets of wind and solar PV generators respectively; $PD^t$ is the total power demand, and $P_{loss}^t$ is the minimum power loss during time period $t$, which can be obtained by solving the problem B in Section III-A2.

2) OPF-based Loss Minimization: The UC problem only considers the active power balance of the MG to make the problem computationally tractable. Therefore, an OPF problem is formulated to examine the practicality of the UC solution. The problem in stage two (problem B) comprises security constraints of the system. The DGs are given a limited degree of freedom about their original dispatch values. The task for the OPF problem is to locate the optimal power dispatch for the DGs which minimizes the cost of power losses in the system while satisfying the system security requirements. This gives optimal reactive power outputs and voltage profile for the MG. Most importantly, Lagrangian multipliers for active power balance equations of each bus can be computed from the dual of the OPF problem. This is called the locational marginal price (LMP) which reflects the cost of next electricity unit at each bus. This is used as the basis to trade power with other MGs. Hence, the benefits of power sharing will be dependent on the buses at which interconnections are available. This two-stage problem decomposition approach reduces the complexity of the original optimization problem thereby improving the overall solution time [2], [3].

The problems A and B are solved alternatively sharing the power dispatch from problem A to B and power losses from problem B to A until convergence. The proof of convergence for this approach is given in [2]. The final outcome of this layer are LMP values and the power surplus or deficit information of the corresponding MG. Fig. 1 illustrates the computations of the EMS layer.

**B. Global Coordination Control for Power Sharing among Microgrids**

There are physical limitations on the power transfer capacity between MGs and also between individual MGs and the main grid. At first, the EMS of each MG schedules generation expecting maximum support from neighboring MGs and the main grid. The EMS will compute LMP values at points of common coupling (PCCs) with neighboring MGs and the power supply (surplus) or demand (deficit) information of each MG along the time frame; $t \in \{1, 2, ..., T\}$. Subsequently, these results will be passed to the tertiary layer which is a global power sharing coordination controller (PSCC). It compares the power exchange preferences/requirements of each MG. Some MGs may wish to supply power (supplier MGs) and others may wish to demand power (purchaser MGs) at time interval $t$. Power sharing can only be facilitated if the demand and supply of two interconnected MGs match each other at the same time interval. PSCC processes the requirements of each MG and decides possible combinations where power sharing can be facilitated. The amount of power to be shared and the cost of power sharing will be computed in the following manner for each possible combination.

Case 1: If $P_{MGp,j,i}^t \geq 0$ and $P_{MGs,j,i}^t \geq 0$; Power exchange can be facilitated at the price offered by the $j^{th}$ MG ($\lambda_{MG,j}^t$). The power transfer from $j^{th}$ MG to $i^{th}$ MG:

$$P_{MG,j,i}^t = \min \left\{ P_{MGp,j,i}^t, P_{MGs,j,i}^t \right\}$$

(9)

Cost of power sharing:

$$C_{PS,j,i}^t = \lambda_{MG,j}^t P_{MG,j,i}^t$$

(10)

Case 2: If $P_{MGs,i,j}^t \geq 0$ and $P_{MGp,i,j}^t \geq 0$; Power exchange can be facilitated at the price offered by the $i^{th}$ MG ($\lambda_{MG,i}^t$). The power transfer from $i^{th}$ MG to $j^{th}$ MG:

$$P_{MG,i,j}^t = \min \left\{ P_{MGs,i,j}^t, P_{MGp,i,j}^t \right\}$$

(11)
Cost of power sharing:

\[ C_{PS,i,j}^t = \lambda_{MG,i}^t P_{MG,i,j}^t \]  

(12)

Case 3: If \( P_{MG,i,j}^t \geq 0 \) and \( P_{MG,j,i}^t \geq 0 \) or \( P_{MG,i,j}^t \geq 0 \) and \( P_{MG,j,i}^t \geq 0 \); Both MGs wish to act as suppliers or purchasers respectively to optimize their operations. In this scenario, power exchange cannot be facilitated between MGs.

The following algorithm describes the computations in the tertiary control layer to coordinate power exchange.

**Algorithm 1 Power Sharing Coordination**

1: Extract LMP values and power exchange preferences/requirements of each MG over the time frame.
2: Select two MGs for comparison (say \( i^{th} \) and \( j^{th} \) MG).
3: for \( t = 1 : T \) do
4: if \( i^{th} \) and \( j^{th} \) MGs are a purchaser-supplier combination at time \( t \) i.e. case 1 or 2 then
5: Set the power sharing limit as the minimum value of the two.
6: Update the LMP values.
7: Calculate the cost of power sharing.
8: else i.e. case 3
9: Set the power sharing limit and cost to zero.
10: end;
11: end;

The PSCC updates power sharing limits. The results are fed back to the EMS to compute the new generator schedule and LMP values. The simulation continues till the maximum relative difference of power sharing cost in two consecutive iterations is lower than the specified tolerance.

**IV. SIMULATION RESULTS AND DISCUSSION**

In the simulations, two grid-connected MGs (MG 1 and MG 2) are considered. Both MGs were assumed to be interconnected. Both MGs were assumed to have DGs, an ESS, a solar PV and a wind power plant as power sources. The characteristics of DGs used in the simulation are shown in [2] (see Table I). MG 1 was assumed to contain all DGs while MG 2 contained only DG 1 and DG 2. Both MGs were assumed to have identical ESSs. For the ESSs, \( B_{cap} \) is 1,020 kWh, \( N \) is taken as 6000 h, \( P_{1E,i} \) is 1020 kW and the cost of ESS is taken as $400 per kW [7]. \( P_{soc}^{max} \) and \( P_{soc}^{min} \) are taken as 300 kW each, and \( SOC^{max} \) and \( SOC^{min} \) are considered as 0.3 p.u. and 0.9 p.u. The initial value of ESS in each MG is set at 0.6 p.u. In the simulations, the \( T_{bc} \) and \( T_{bd} \) were found to be around 3 h for each MG. \( \eta_{bc} \) and \( \eta_{bd} \) are both taken as 0.95 [12]. Forecasted solar PV and wind power plant power generation profiles are taken from [2]. Power purchase and sale prices for the main grid is taken from [13] for 01st of Jan 2016. The maximum power transfer limits are taken as 500 kW with the main grid and 1000 kW with the other MG.

MG 1 and MG 2 systems are assumed to be standard IEEE 30-bus and 14-bus test systems respectively [14]. The base value is considered as 8000 kVAr and the line resistances values were increased to 5 times that of the p.u. values provided in MATPOWER [14]. The p.u. values of line reactance are kept unchanged for both MGs. In MG 1, DGs 1, 2 and 3 are connected to buses 27, 2 and 3 respectively. Both wind power plants and ESS are connected to bus 22 and the Solar PV plant is connected to bus 13. Buses 1 and 23 are points of common coupling with the main grid and MG 2 respectively. In MG 2, DGs 1 and 2 are connected to buses 3 and 8 respectively. Both wind power plant and ESS are connected to bus 6 and the Solar PV plant is connected to bus 2. Buses 1 and 14 are PCCs with the main grid and MG 1 respectively.

The algorithm is implemented in MATLAB. The optimal scheduling problem is formulated using YALMIP [15] and solved using CPLEX. The matrices generated from the MLD model using HYSDEL are used to formulate constraints for the scheduling problem. The OPF simulations are performed using the MATPOWER OPF solver package [14].

In the simulations, the optimal generation schedule for each MG without enabling power sharing was first computed. Then, after enabling power sharing among MGs, the changes in the generator schedule for both MGs are observed. In both cases, MGs are kept connected with the main grid. Fig 2 (a) and (c) depict the dispatch of DGs along with load profiles for MG 1 and MG 2 respectively. It can be seen that all DGs are operated during peak demand hours for both MGs. Fig 2 (b) and (d), show power exchanges with main grid, and charge and discharge power of ESS. In MG 1, discharges during peak demand hours. However, ESS of MG 2 discharges during two time intervals and charges to its maximum SOC during load valley periods. Most importantly, MG 1 demands power from the main grid for 15 hours including the peak demand hours and supplies power for 8 hours during the off-peak hours. Altogether, MG 1 demands 2,916.8 kWh from the main grid. However, MG 2 acts mostly as a supplier to the main grid. It demands power only for 3 distinct hours and supplies power during the remaining hours including peak demand hours. The total power supplied is 8,168.6 kWh. The total operating cost (TOC) is $14,968 for MG 1 and $5,112 for MG 2.

Fig 3 (a), (b), (c) and (d) show the power generation of two MGs when power sharing is enabled. It is clear that all DGs are operated during peak demand hours for both MGs. The behavior of ESSs of the two MGs is more or less similar to the earlier case when power sharing was disabled. In addition to the parameters mentioned in the previous paragraph, Power exchange in between two MGs are depicted in Fig 3 (b) and (d). It is observed that power transfer happens only from MG 1 to MG 2. This is determined by the LMP values at each hour for the PCC in between the two MGs. The total energy transferred in 9 hours is 4,372 kWh. An interesting observation is that during hours 9-11 (which are its peak demand hours), MG 1 purchases energy (1,647 kWh in total) from MG 2 and supplies energy (1,074.5 kWh in total) to the main grid. The power loss of MG 1 is higher for this 3-hour time interval. Therefore, the EMS tries to adjust power flow so as to reduce the cost due to power losses. A similar scenario is observed in MG 2 for hours 5-6. MG 2 supplies 1,366.4 kWh in total to MG 1 and purchases 933.6 kWh in total from the main grid.
Further, due to power sharing, the dependency of MG 1 on the main grid is reduced. It only demands a total of 323 kWh from main grid. Also, MG 2 supplies less energy to the main grid (6,704.8 kWh). However, the combination of MG 1 and MG 2 supplies 1,130 kWh more energy to the main grid. The total operating cost (TOC) is $14,830 (reduction of $138) for MG 1 and $5,108 (reduction of $4) for MG 2. DG 1 and DG 2 of both MGs are selected with identical operating characteristics. Moreover, MG 1 has a higher load factor (80.8%) compared to MG 2 (66.2%). These may be the reasons why power transfer happens only in one direction (from MG 2 to MG 1). Power losses of both systems are dependent on the chosen PCCs. In this simulation, some buses are randomly selected as PCCs.

V. CONCLUSIONS AND FUTURE WORKS

A multi-layered control architecture is presented in this paper to coordinate power sharing efficiently between interconnected MGs. The proposed approach optimizes the operational cost of each MG separately while also sharing power with neighboring MGs whenever possible. The secondary layer optimizes generation schedule while the tertiary layer tries to facilitate power sharing. Two distinct MGs are used in simulations. The results clearly show that with power sharing coordination, the combination (MG 1 and MG 2) has reduced grid dependency, increased the power supply to the main grid and reduced total operating cost in conclusion. In future work, we would like to consider scenarios with more number of MGs with different load profiles. It is also interesting to extend the problem formulation to explore how power sharing can be optimized to reduce load shedding and maintain reserve requirements.

REFERENCES


