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Stochastic multi-objective operational planning of smart distribution systems considering demand response programs

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ABSTRACT

The development of smart grids offers new opportunities to improve the efficiency of operation of Distributed Energy Resources (DERs) by implementing an intelligent Distribution Management System (DMS). The DMS consists of application systems that are used to support the DERs management undertaken by a Distribution System Operator (DSO). In this paper, a conceptual model for a Demand Response Management System (DRMS), conceived as an application system of a DMS, is presented. Moreover, an optimization tool, able to consider the available DERs (conventional or renewable Distributed Generations (DGs) and demand response) is proposed. The optimization tool uses a stochastic multi-objective method in order to schedule DERs and aims at minimizing the total operational costs and emissions while considering the intermittent nature of wind and solar power as well as demand forecast errors. In order to facilitate small and medium loads participation in demand response programs, a Demand Response Provider (DRP) aggregates offers for load reduction. The proposed scheduling approach for DERs is tested on a 69-bus distribution test system over a 24-h period.

1. Introduction

Future distribution systems will face with a huge penetration of Distributed Energy Resources (DERs) that may effect on reliable and secure operation of the system and the intermittent nature of renewable generation may put at risk the system operation [1]. Efficient and robust DERs scheduling models are, therefore, necessary for future distribution system operation and control. In order to implement advanced scheduling of DERs for reliable and economic operation of future distribution systems, Advanced Metering Infrastructure (AMI) integrated with application systems represents an essential infrastructure [2–6]. Application systems refer to software systems responsible for monitoring, measurement and control of the electrical grid in order to ensure its reliability and availability as well as the energy management while guaranteeing balanced supply and demand [7–9]. As defined in IEC 61968, a Distribution Management System (DMS) consists of various distributed application components able to manage electrical distribution networks [10]. These capabilities include monitoring and control of equipment for power delivery, management processes to ensure system reliability, demand-side management, voltage management, outage management, automated mapping, work management and facilities management [10,11]. Application systems allow Distribution System Operators (DSOs) optimizing the use of Distributed Generation (DG) and enable customers to participate in various Demand Side Management (DSM) programs. Also, AMI system allows real-time communication between customers, service providers and utilities in order to send and receive useful energy and price information, as well as offer and command signals.

Demand Response (DR), known as an important DER, is a valuable resource for secure and economic operation of the power system. A survey of DR potentials and benefits in smart grids is presented in [12]. Innovative enabling technologies and systems, critical to enable the management of DR in a smart grid, are discussed also considering research projects and real industrial case studies.

In general, DR includes all planned electricity consumption pattern modifications by end-use customers that are intended to modify the timing and/or the level of their electricity consumption in response to incentive payments or to changes in the price signal over time. In order to evolve to successful practical implementations of all types of DR programs, distribution systems require new Information Technology (IT) systems [12–14] as well as application systems that manage and schedule all available DERs. Demand Response Management System (DRMS) is introduced as one of

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Nomenclature

Sets
- t index of optimization periods, $t=1,2,\ldots,24$
- i index of demand response providers, $i=1,2,\ldots,I$
- ξ index of steps in load reduction offer, $\xi=2,3,\ldots,\Phi$
- j index of non-renewable DGs, $j=1,2,\ldots,J$
- s index of scenarios, $s=1,2,\ldots,S$
- w index of wind turbines, $w=1,2,\ldots,W$
- pv index of photovoltaic (PV) units, $pv=1,2,\ldots,\Theta$
- n,m index of buses, $n,m=1,2,\ldots,N$
- k index of objective functions, $k=1,\ldots,K$
- z index of Pareto-optimal solutions, $z=1,\ldots,q_k$

Binary variables
- $u(j,t)$ on/off status (1/0) of the non-renewable DG j in period t

Continuous variables
- F_{cost} total expected cost
- $F_{emission}$ total emissions
- l_ξ^i accepted load reduction of DRP i in step ξ of the price-quantity offer package
- $DR^E(i,t,s)$ total scheduled load reduction quantity prepared by DRP i in period t and scenario s
- $C^{DR}(i,t,s)$ cost due for load reduction provided by DRP i in period t and scenario s
- $DR^R(i,t)$ scheduled reserve provided by DRP i in period t
- $RC^{DR}(i,t)$ cost due for reserve supply by DRP i in period t
- $P_g(t)$ scheduled hourly power from the main grid in period t
- $C_{DG}(j,t,s)$ hourly running cost of non-renewable DG j in period t and scenario s
- $fc(j,t)$ hourly fixed running cost of non-renewable DG j in period t
- $SU(j,t)$ start up cost of non-renewable DG j in period t
- $ENS(n,t,s)$ amount of involuntarily load shedding at bus n in period t and scenario s
- $P_{DG}(j,t,s)$ active output power of non-renewable DG j in period t and scenario s
- $R_{DG}(j,t)$ scheduled spinning reserve provided by non-renewable DG j in period t
- $V(n,t,s)$ voltage at bus n in period t and scenario s

Parameters
- $D_{n,t,s}$ hourly demand at bus n in period t and scenario s
- $P_{s,t}^{w}$ output power of wind turbine w in period t and scenario s
- $P_{s,t}^{pv}$ output power of PV system pv in period t and scenario s
- L_{Min}^i minimum quantity of load reduction offered by DRP i in period t
- L_{Max}^i maximum quantity of load reduction offered by DRP i in period t
- O_ξ^i price offer of DRP i for load reduction at step ξ
- $q_{i,t}$ price offer of DPR i for providing reserve in period t
- $E_{CO_2}^{grid,t}$ average emission rate of the main grid generation system in period t (kg/MWh)
- $D_{CO_2}^{DG,j}$ emission rate of DG j (kg/MWh)
- v wind speed (m/s)
- si solar irradiance (kW/m^2)
- Ω_t hourly electricity price of the open market
- $RP_{j,t}$ reserve price of non-renewable DG j in period t
- V_t Value of Lost Load (VOLL) in period t

Sets
- $P_{DG,j}^{min}$ minimum output power limit of non-renewable DG j
- $P_{DG,j}^{max}$ maximum output power limit of non-renewable DG j
- Sc_j start-up cost of non-renewable DG j
- $Y_{n,m}$ element (n,m) of the admittance matrix

these application systems within a DMS that supports DSO in order to manage DR programs and control DGs operations in a distribution system [15,16]. Future DMSs must be designed to support the integration of DERs into distribution networks. A significant number of works is contributing to the diversity of new features required for DMS and also evidencing challenges that they must face [17–19]. In [17], the management tools of conventional distribution systems have been compared with those of smart grid systems. In [18], conventional distribution automation has been compared with smart distribution management. In addition, distribution state estimation, Volt/Var control, and network reconfiguration have been presented in the paper as solutions for smart distribution application systems. In [19], algorithms for DMS have been presented in which load estimation, power flow, and optimal reconfiguration for loss minimization were taken into account. However, an application system for DR program management has not been presented in these works.

In [20] a conceptual design of an intelligent Supervisory Control and Data Acquisition (SCADA) has been proposed. The SCADA model is used to support the energy resource management undertaken by a DSO. DER management considers all the involved costs, power flows, and electricity prices, allowing the use of network reconfiguration and load curtailment. Direct load control (DLC) and locational marginal prices triggered events have been considered as DR programs. However, the intermittent nature of renewable generation as well as reserve scheduling were not taken into account in the model.

An intelligent on-line DSM system for peak load management in low-voltage distribution networks has been presented in [21]. The system uses low-cost controllers with low-bandwidth two-way communication installed in customers' premises and at distribution transformers in order to manage the peak load while maximizing customer satisfaction. Reserve scheduling as an ancillary service and incentive based DR were not taken into account in the model. An energy management system (EMS) aiming at optimizing the smart grid's operation has been proposed in [22]. The EMS behaves as a sort of aggregator of DERs allowing the SG participating in the open market. By integrating demand side management and active management schemes, it permits an enhanced exploitation of renewable energy sources and a reduction of the customers' energy consumption costs with both economic and environmental benefits.

A lot of good work has been historically done on DSM and DR programs [23–28]. The schemes can generally be classified into either dispatchable or non-dispatchable [16,23]. Non-dispatchable DR resource, often known as price-based DR, refers to some DR programs according to which the consumer consumption patterns are amended by different electricity prices over the time [24,25]. real time pricing (RTP) and time of use (TOU) are located in this category. As the customer decides whether and when to reduce consumption and the amount of consumer electricity usage changes cannot be exactly determined before the real time, this type of DR programs are called non-dispatchable and the operator cannot consider them in the day-ahead energy and reserve scheduling. Dispatchable DR resource, known as incentive-based DR, refers to planned changes