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Contribution of emergency demand response programs in power system reliability

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ABSTRACT

Nowadays, demand response has become one of the essential components of recent deregulated power systems as it can offer many distinguished features, such as availability, quickness, and applicability. DRPs (Demand response programs), announced by the federal energy regulatory commission, are among the most accepted and practical features of demand side management. DRPs not only can contribute in mitigating the intermittent effects of renewable energy resources but also can be used either to lower high energy prices, occurred in wholesale electricity markets, or when the security of power systems is at risk. In this paper, the influence of emergency demand response programs in improving reliability in case of failure of generation units is investigated. In the proposed reliability based optimization approach, the generation failure is modeled based on its forced outage rate. The proposed method can help independent system operators to schedule day-ahead generating units in a more reliable manner and can facilitate the participation of consumers to increase the total social welfare in the case of an emergency. Moreover, the mixed integer programming formulation allows implementing the proposed method by using available tractable linear solvers. Eventually, the applicability of the proposed model is tested on the IEEE 24-bus reliability test system and its effects on the value of lost load and the expected load not served are discussed.

1. Introduction

1.1. Definitions and aims

In recent deregulated power systems, utilizing any available source of energy seems crucial. DR (Demand response), enabled through communication infrastructures [1], is one of the main methods that can be taken in order to decrease consumer electrical energy consumption when contingencies, like unpredictable variations in demand or generation, or unit outages take place and can prevent the balance of supply and demand. These programs can be implemented either through coordinated [2] or non-coordinated [3] schemes. Coordinated schemes refer to decentralized control strategies, while non-coordinated schemes are utilized by central operators through some procedures such as DLC (Direct Load Control) or RTP (Real-Time Pricing). Among the recently introduced sources are DRRs (Demand Response Resources), can, indeed, mitigate some problems existing in the conventional power systems and improve the overall system reliability, considerably [4–6]. To this aim, versatile DRPs (Demand Response Programs) have been introduced by FERC (Federal Energy Regulatory Commission) to classify the many different features of the DSM (Demand Side Management) [7–9]. Previously announced classification by FERC [7,8] have been recently modified by adding many new programs along with merging some of the conventional ones [9]. EDRPs (Emergency Demand Response Programs) are among the most widely used programs mainly because the participation in these kinds of programs is voluntary and may bring economic benefits for participants.

In order to examine the functionality of the DRPs, it is worth mentioning the recent definition of DR, announced by FERC. According to the given definition, "*any change in electric use by*

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Nomenclature

$A(.)$	Incentive value.
$a(.)$, $b(.)$, $c(.)$	Fuel cost coefficients of a unit.
b	Index of buses
$Cost_{Inc}(.)$	Total incentive cost.
$Cost_{Gen}(.)$	Fuel cost of a unit in an hour.
$D_0(.)$	Initial load demand in an hour.
$D_{DR}(.)$	Final calculated fixed and elastic demand in an hour.
D_{min}	Minimum amount of load reduction.
$dlp(.)$	Slope of a segment in linearized demand function
$dr(.)$	Demand response in segment n in an hour.
$\Delta D(.)$	Demand change per hour.
$\Delta Pr(.)$	Price deviation per hour.
$Elast(.)$	Price elasticity of demand.
$ELNS(.)$	Expected load not served ($/h).
$ELNS^{MAX}$	Maximum amount of *ELNS*
$F(.)$	Transmission line flow per hour.
$FOR(.)$	Forced outage rate.
$F^{max}(.)$	Transmission flow limit.
i	Index for conventional unit.
j_{lin}, h_{lin}	Linear demand vs. price coefficients.
k	Index for contingency.
$LS(.)$	Load shedding of bus b during contingency k in an hour.
$LS^{max}(.)$	Maximum amount of load shedding.
L_b	Number of transmission lines connected to bus b.
MU, MD	Minimum up and down time of generators.
MU_d, MD_d	Minimum up and down time of responsive demand
N_B	Number of buses.
N_{seg}	Number of linearization segments of fuel cost functions.
N_{Gen}	Number of conventional thermal units.
$N_{Gen(b)}$	Number of generating units connected to bus b.
$p\ (.)$	Power generation of a unit.
$P^{min}(.)$, $P^{max}(.)$	Minimum/maximum generating capacity of a unit.
$Pr_0(.)$	Initial electricity price per hour.
$\pi(.)$	Probability of a generator contingency.
$r(.)$	Binary DR status
$RU(.)$, $RD(.)$	Ramp up/down limit of a unit.
$SC(.)$	Start up cost of unit i.
$SU(.)$	Startup cost of a unit.
$SR\ (.)$	Spinning reserve per hour.
$slp(.)$	Slope of a segment of a unit in linear function
$\delta_s(.)$, $\delta_r(.)$	Voltage angles.
t	Index for time.
τ	Spinning reserve market lead-time.
$UT(.)$, $TD(.)$	Number of hours a unit has been on/off at the beginning of the scheduling period.
$u(.)$	Binary indicator of a unit status.
$VOLL(.)$	Value of lost load ($/MWh).
$w(.)$	Indicator of generation unit outage; 0:outage occurred/1:otherwise
$X(.)$	Reactance of transmission line.
$y(.)$	Startup indicator.
$y_d(.)$	Startup indicator of DR.
$z(.)$	Shutdown indicator.
$z_d(.)$	Shutdown indicator of DR.

demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized is called DR". This definition substitutes "end-use customers", used in previous survey, with "demand-side resources" in order to follow the definition used by NERC's (North American Electric Reliability Corporation) Demand Response Data Task Force the development of a Demand Response Availability Data System to collect DRP information [9]. End-use customers also can be classified into four categories: residential, commercial, industrial, and municipal customers where residential [2]and industrial customers [10] seem to be great candidates for DR implementation so far.

Although, three major categories of DRPs (i.e., time of use programs, voluntary programs, and mandatory programs) were previously announced by FERC, DRPs have been recently categorized as: interruptible load, direct load control, critical peak pricing with load control, load as capacity resources, spinning reserve, non-spinning reserve, emergency demand response, regulation service, demand bidding and buyback, time-of-use pricing, critical peak pricing, real time pricing, peak time rebate, system peak response transmission tariff, and other programs [4–6].

According to what is requested by Ref. [11], about examining any possible improvement in conducting DRPs, in this paper EDRPs in a SCUC (Security Constrained Unit Commitment) problem are explored.

1.2. Literature review

There is a possibility for some customers to control or schedule their demand based on the electricity prices. This idea is formulated in Ref. [12] and the concept of spot pricing of electricity is introduced. Generation scheduling and determining the price of electricity in a pool market are discussed in Ref. [12]. The model of price elasticity of electricity demand is also described in Ref. [13]. The FERC staff annual surveys since 2006 [7–9] tracked the concept of demand responsiveness. The DRPs were firstly categorized into two main groups including, incentive and time based programs [7]. In Ref. [5], this classification has been changed and detailed sub-classifications of the incentive based DRPs have been introduced, i.e., voluntary and mandatory based programs and market clearing programs. The recent issue of the survey [9] declared fifteen separate versatile programs without classifying them into the above-mentioned two main groups.

In Ref. [14], an innovative method was proposed to find the customers that can contribute in I/C (interruptible/curtailable) programs while their maximum benefit is achieved. To do this, a procedure was proposed to support the regulator of the system by selecting and prioritizing DRPs by using a TOPSIS (Technique for Order Preference by Similarity to Ideal Solution) method. The most effective DPR were selected by using an AHP (Analytical Hierarchy Process) method in Ref. [15]. To propose a comprehensive model for DRPs, all possible demand vs. price functions have been combined in Ref. [16] by using a Q-learning method based on a weighting. In Ref. [17], authors tried to integrate DR programs in power systems with high renewable penetration rate through optimization of electricity price of electric storage space heating customers, in order to maximize the profit of the retailer.

In Ref. [18], a pool-based demand response exchange model has been proposed as an alternative for managing the variability of renewable energy sources. In this area, many outstanding papers have been published. In Ref. [3], a new demand response method