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Reliability assessment of incentive- and priced-based demand response programs in restructured power systems

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ABSTRACT

Fostering demand response (DR) through incentive-based and priced-based programs has always great impact on improvement of efficiency and reliability of the power systems. The use of DR lowers undesirable effects of failures that usually impose financial costs and inconveniences to the customers. Hence, quantifying the impact of demand response programs (DRPs) on reliability improvement of the restructured power systems is an important challenge for the independent system operators and the regional transmission organizations.

In this paper, the DR model which treats consistently the main characteristics of the demand curve is developed for modeling. In proposed model, some penalties for customers in case of no responding to load reduction and incentives for customers who respond to reducing their loads are considered.

In order to make analytical evaluation of the reliability, a mixed integer DC optimal power flow is proposed by which load curtailments and generation re-dispatches for each contingency state are determined. Both transmission and generation failures are considered in contingency enumeration. The proposed technique is modeled in the GAMS software and solved using CPLEX as a powerful mixed integer linear programming (MILP) solver. Both supply-side reliability for generation companies and demand-side reliability for customers are calculated using this technique.

In order to simulate customers' behavior to different DRPs in a real power network, the proposed DR model is used and evaluated over Iranian power network. In order to investigate the reliability effects of DRPs based on proposed reliability method, DRPs based on the DR model are implemented over the IEEE RTS 24-bus test system, and reliability indices for generation companies, transmission network and customers are calculated. Using proposed performance index, the priority of the DRPs are determined from view point of customers, generation companies, transmission network and the whole system in IEEE RTS.

1. Introduction

With the advent of competitive electricity markets and increased competition between producers for selling electricity to consumers, traditional demand-side management (DSM) is no longer efficient and new concept in consistent with the new framework should be adopted. demand-side participation (DSP) or demand response program (DR) is compatible mechanisms with deregulated environment.

The definition of "demand response" that is used by the U.S. Department of Energy (DOE) is as follows: "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" [1].

According to DOE classification, demand response programs (DRPs) are divided into two categories as shown in Table 1.

Depends on the electricity market structure, either price-based or incentive-based programs can be launched for DR implementation. In the following a brief descriptions of DRPs have been presented. This helps to recognize the similarities and distinctions of different programs and their unique characteristics. More detailed explanations can be found in [1,2].

A – Price-based demand response programs:

- *Time-of-use (TOU) rates*, which reflect to customers the daily and seasonal variations of the electricity costs during peak or off-peak hours. They are fixed in advance and usually reflect the average price of supplying electricity in certain periods.

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Table 1
Demand response programs.

Price-based programs	Incentive-based programs
Demand response programs	
Time-of-use (TOU)	Direct load control (DLC)
Real-time pricing (RTP)	Interruptible/curtailable (I/C) service
Critical peak pricing (CPP)	Demand bidding/buyback programs (DB)
	Emergency demand response programs (EDRP)
	Capacity market programs (CAP)
	Ancillary services market programs (A/S)

- *Real-time pricing (RTP)* provides hourly prices to customers. It might vary continuously during a day. In fact, RTP links hourly prices to hourly changes in a day-of (real-time) or day-ahead cost of power.
- *Critical peak pricing (CPP) rates* are essentially similar to TOU rates with the addition of a critical peak price that is called on a day-of basis.

B – Incentive-based demand response programs:

- *Direct load control programs (DLC)* are typically reliability-based and can be deployed within minutes because the utility or system operator directly shuts down or cycles a customer's electrical equipment on a short notice, without waiting for a customer-induced response, in exchange for an incentive payment or bill credit.
- *Interruptible/curtailable (I/C) programs* curtailment options integrated into tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties maybe assessed for failure to curtail.
- Load reductions from *demand buyback* or *bidding programs (DB)* are typically scheduled day-ahead, and incentive payments are valued and coordinated with day-ahead energy markets.
- *Emergency demand response programs (EDRP)* are reliability-based and provide incentive payments to customers for reducing their loads during events, but curtailment is voluntary.
- *Capacity market programs (CAP)* involve pre specified load reduction commitments made ahead of time; the system operator has the option to call when system contingencies arise. The call option is usually exercised with two or less hours of notice, depending on the specific program design.
- *Ancillary services market programs (A/S)* also involve customer load commitment bids ahead of time. Customers whose operating reserve market bids are accepted must then be standby to provide load reductions, if their load curtailments are needed; they are called by the ISO often with less than an hour's notice [3].

One way to support reliability of a power system is to take the advantages of the DRPs implementation. DRPs will enable the system operator, even during the peak hour, to provide efficiently the spinning reserve capacity. This yields to promote the reliability performance indices by decreasing energy or demand not-supplied values for sensitive loads. With demand response, not only customers gain benefits but the system operator will have more options and flexibility for providing systems security [4–6]. One challenge for independent system operators (ISOs) and regional transmission organizations (RTOs) is to how quantify and measure the effect of DRPs on improvement of reliability in restructured environment. In this paper, our endeavors have been focused to address such a challenging problem.

In [7,8], a linear economic model for DRPs have been developed. This simple and widely used model is based on an assumption in which demand will change linearly in respect to the elasticity. The outstanding researches about the use of linear demand function have been presented and analyzed in [9,10]. However, those models do not consider nonlinear behavior of the demand which is of great importance in analyzing and yielding the results.

Considerable efforts have been done to develop analytical techniques for bulk power system reliability assessment in traditional vertically integrated and restructured power systems [11–18]. In analytical technique, a number of combinations for components failures known as states are generated which may involve line failures and/or unit outages. For critical states that result in system violations, it is required to take proper remedial actions such as generation re-dispatched and load shedding. Recent methods are based on optimal power flow (OPF) problem, they have been concentrated on improving the contingency analysis performance by integrating remedial/corrective actions into an optimization model to reach minimum load shedding values [16,17]. It is required that the objective or constraints of optimization model for load shedding and generation re-dispatch problems used in OPF-based techniques have to be modified to incorporate requirements of restructured environment. In [18,19], the authors proposed to substitute the objective function by customer damage function instead of just considering total amount of load shedding in order to observe and minimize the overall costs of the system which includes generation, reserve and load interruption costs. Apart from the selected method, system reliability indices such as loss of load probabilities, frequencies, and durations can be calculated based on the results of load shedding [20,21].

Most of the existing OPF-based methods have no mechanism to shut down generators which are more expensive for operation or hit technical primary constraints in stressed conditions. The OPF formulation, however, can only dispatch the generating units at their minimum limits. In this paper, considering a pool-based electricity market structure, to evaluate reliability performance of the network, a mixed integer optimization technique is proposed which determines load curtailment and generation re-dispatch in each contingency state. The proposed formulation includes the capability of implementing DCOPF combined with unit decommitment procedure for a single time period. Both transmission and generation failures are included in contingency enumeration. The reliability performance indices are calculated for both supply-side generation and demand-side using the proposed reliability evaluation method. The proposed method, here, is formulated by GAMS programming language and solved using the CPLEX as a powerful solver in mixed integer linear programming (MILP). Also in this paper, demands are treated by their nonlinear characteristics to the electricity price alteration by assuming constant elasticity for demand curves. In this regard, a model to describe price dependent loads is developed such that the characteristics of different types of DR program can be imitated by introducing some incentive or penalty factors into the formulation.

The remaining parts of the paper are organized as following: Modeling DR based on the concept of price elasticity of demand is developed by considering penalty and incentive terms in Section 2. The proposed reliability evaluation method is introduced in Section 3. In this section the used method for computation of reliability indices from view of load points, Gencos, Transco and the whole system are introduced. Also a performance index is defined and proposed based on the computed reliability indices to prioritize DRPs from views of different market participants. In Section 4, to simulate DRPs, the extended DR model has been applied and implemented over the IEEE 24-bus reliability test system. Afterwards, reliability indices for Gencos, consumers, and transmission network are calculated based on the method proposed for the reliability evaluation. Also the considered DRPs are prioritized from view points of the customers, generation companies, transmission