

# Impact of EDRP on Composite Reliability of Restructured Power Systems

Rahmat Azami, Amir Hossein Abbasi, Jamal Shakeri, Amir Faraji Fard

**Abstract--** With the development of restructured power systems and increase of prices in some hours of day and increase fuel price, demand response programs were noticed more by customers. demand response consists of a series of activities that governments or utilities design to change the amount or time of electric energy consumption, to achieve better social welfare or some times for maximizing the benefits of utilities or consumers

In this paper the effect of emergency demand response program on composite system reliability of a deregulated power system is evaluated using an economic load model, AC power-flow-based load curtailment cost function and reliability evaluation techniques.

In this paper for calculation the reliability indexes, the Emergency Demand Response Program (EDRP) cost is considered and in each contingency state, the EDRP cost with the customer load curtailment cost is compared and the load appropriate value is selected for load shedding or participating in EDRP. In the next stage, the system and nodal reliability indexes are calculated.

To investigate the impact of EDRP activity on composite reliability of restructured power systems the IEEE 6 bus Roy Billinton Test System is utilized.

According to obtained results, EDRP using lead to increasing nodal and system reliability. It can be said that solving problems such as congestion in transmission lines, power system reliability decrease at load network peak hours, is impossible without customer interfering in power market. In other hand Consumer participation, makes the power markets more competition and enhance its performance.

**Index Terms--** Emergency demand response program (EDRP), power system deregulation, reliability.

## I. INTRODUCTION

Participant of customers in electricity market increases the competitiveness of electricity markets. When customers see price volatility, they modify their demand which helps the magnitude of price spikes[0] be reduced. When consumers can receive price signals and can respond to them, some of them will shift their demand to cheaper hours when they face high prices. Demand Response (DR) can be defined as the changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. [1].

DR is divided into two basic groups and several subgroups:

A- Incentive-based programs:

A-1- Direct Load Control (DLC)

A-2- Interruptible/curtail able service (I/C)

A-3- Demand Bidding/Buy Back

A-4- Emergency Demand Response Program (EDRP)

A-5- Capacity Market Program (CAP)

A-6- Ancillary Service Markets (A/S)

B- Time-based programs:

B-1- Time-of-Use (TOU) program

B-2- Real Time Pricing (RTP) program

B-3- Critical Peak Pricing (CCP) Program

The benefits of DR include increased static and dynamic efficiency, better capacity utilization, pricing patterns that better reflect actual costs, reduction of price spikes, decentralized mitigation of market power, and improved risk management.

A recent study estimated the prospective benefits of active demand response at \$7.5 billion by 2010 (ICF 2002). Other studies, described in GAO (2004), give further details of the benefits that have already been generated because of demand response and active retail choice [2].

Emergency Demand Response program (EDRP) is the most usual demand response program when an event occurs. EDRP provides incentives for customers to reduce loads during reliability events, though the curtailment is voluntary. No penalty is assessed if customers do not curtail, and the rates are pre-specified, though no capacity payments are received [3].

Emergency Demand Response Program (EDRP) is a reliability-specific day-of interpretability contract that is available for hours when there is a shortfall in reliability reserves. Customers can choose to allow the ISO to interrupt their service, for which the customer is paid a price determined through a bidding process [3].

EDRP is an emergency DR program that provides mechanisms where demand can be reduced on short notice when reserve shortfalls are forecasted. EDRP is a voluntary emergency program that pays customers an incentive which, for example, is more than 500 \$/MWh in New York power market or can be the prevailing real-time market price for curtailments of at least four hours long when called by the ISO [3].

The New York Independent System Operator (NYISO) calculated that its demand response program provided substantial benefits to the market by helping the power grid

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recover from the August 2003 Blackout. Specifically, they estimated that on August 15, 2003, the participating DR of 593.9 MW provided \$50.8 M (US) worth of economic benefits at a cost of \$5.9 M (US).

During August 2001, higher-than-normal temperatures forced the NYISO to invoke emergencies on August 7, 8, and 9 (18 hours in all zones) and on August 10 (4.5 hours in New York City/Long Island and Hudson River, Zones F–K). On August 9th, a new record peak load of 30,983 MW was established. Most of the capacity shortfall occurred in the New York City/Long Island area (Zones J–K). During this time, a variety of load management programs, including the PRL1 programs (EDRP, DADRP2, and ICAP), were deployed. At peak load, an estimated 1,580 MW was curtailed, of which the PRL programs contributed 605 MW (38 percent), with the balance coming from other sources. At the time the EDRP events were called, 292 participants had registered in the EDRP. Participants in the EDRP provided 70 percent of all load curtailment from all PRL programs. While 292 participants (712 MW) registered with the NYISO for EDRP, only 213 (617 MW) actually performed when emergencies were declared. Those who performed delivered only an average 418 MW per hour, or 68 percent of their registered capability. A planning consideration for future rounds of the EDRP, given that it is a voluntary program, is that more loads have to be registered than is actually required [3]–[4].

There is a growing concern about the reliability of power systems under a market environment, especially after the blackouts in North America and Europe in 2003.

Bulk power system operators primarily rely on adjustments in generation output (MW movements up or down) to keep the system reliability.

In principle, changes in electricity demand could serve as well as generator movements in meeting the reliability requirements [5]. So, customer loads could be able to participate in these markets. The participation of these resources will either enhance reliability or lower costs of maintaining reliability for all customers and will save money for participating customers.

This paper investigates the impacts of emergency demand response program on system and nodal reliability in a state enumeration approach. A small reliability test system, RBTS, is studied for which the simulation results show that, using emergency demand response program, the system and nodal reliability is improved.

This paper is organized in five sections. Section 2 defines the load economic model which is used to evaluate the participation in emergency demand response program and explains the economic analysis formulation. Reliability Index Calculation is discussed in section 3. Section 4 presents the numerical results which have been tested on RBTS and finally section 5 is dedicated to the conclusions.

## II. DEMAND RESPONSE ECONOMIC MODELING

In the beginning of the deregulation, usually consumers did not have effective participation in the power markets and therefore they were not able to respond to the prices effectively. However, the development of the restructured power systems has been accompanied by many problems, for example reduced system reliability.

Fig. 1 shows how the demand elasticity could effect on electricity prices [6].

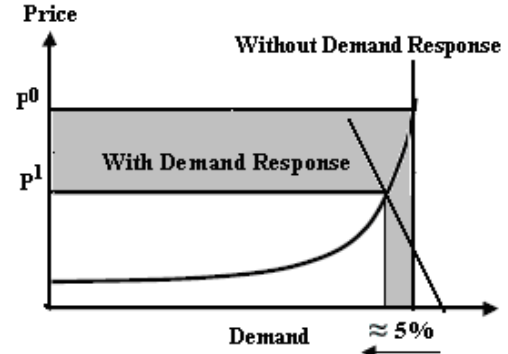


Fig1. Effect of demand variation on the electric energy price [6]

Elasticity is defined as the ratio of the relative change in demand to the relative change in price:

$$E = \frac{\partial q}{\partial p} = \frac{\rho_0}{q_0} \cdot \frac{dq}{dp} \quad (1)$$

Where:

$\Delta d(t_i)$ : Demand changes in time interval  $t_i$

$\Delta \rho(t_i)$ : Price changes in interval  $t_i$

$\Delta \rho(t_j)$ : Price changes in time interval  $t_j$

According to equation (2), self elasticity ( $\xi_{ii}$ ) and cross elasticity ( $\xi_{ij}$ ) can be written as:

$$\xi_{ii} = \frac{\Delta d(t_i) / d_0}{\Delta \rho(t_i) / \rho_0} \quad (2)$$

$$\xi_{ij} = \frac{\Delta d(t_i) / d_0}{\Delta \rho(t_j) / \rho_0}$$

Where:

$\Delta d(t_i)$ : Demand changes in time interval  $t_i$

$\Delta \rho(t_i)$ : Price changes in interval  $t_i$

$\Delta \rho(t_j)$ : Price changes in time interval  $t_j$

Self elasticity and cross elasticity are negative and positive values, respectively. If the relative change in demand is larger than the relative change in price, the demand is said to be elastic, on the other hand, if the relative change in demand is smaller than the relative change in price, the demand is said to be inelastic. So the elasticity coefficients can be arranged in a 24 by 24 matrix  $\mathbf{E}$  [6].

The detailed process of modeling and formulating how the

<sup>1</sup> Price Responsive Load

<sup>2</sup> Day-Ahead Demand Reduction Program

EDRP program affects on the electricity demand and how the maximum benefit of customers is achieved, have been discussed in [7]. Accordingly the final responsive economic model is presented by (3):

$$d(i) = \left\{ d_0(i) + \sum_{j=1}^{24} E_0(i, j) \cdot \frac{d_0(i)}{\rho_0(j)} \times A(j) + \frac{E(i)[\rho(i) - \rho_0(i) + A(i)]}{\rho_0(i)} \right\} \quad i = 1, 2, \dots, 24. \quad (3)$$

The above equation shows how much should be the customer's demand in order to achieve maximum benefit in a 24-hours interval.

Time period is assumed to be one hour. Variable load curve for 24 hours within one day are considered in the simulations.

#### A. Modeling of EDRP

The final response of the economic model is presented by (4). The modified model for showing the effect of EDRP is as follows:

For  $i = \text{EDRP Non-Event Hours}$

$$d(i) = \left\{ d_0(i) + \sum_{j=14}^{18} E_0(i, j) \cdot \frac{d_0(i)}{\rho_0(j)} \times A(j) \right\} \quad (4)$$

For  $i = \text{EDRP Event Hours}$

$$d(i) = \left\{ d_0(i) + \sum_{j=14}^{18} E_0(i, j) \cdot \frac{d_0(i)}{\rho_0(j)} \times A(j) + \frac{E(i) \times A(i)}{\rho_0(i)} \right\} \quad (5)$$

### III. RELIABILITY INDEX CALCULATION

Reliability assessment methodologies of bulk power systems are clearly described in [8].

A composite system contains both generation and transmission facilities and is sometimes designated as a composite generation and transmission system.

According to the method of selecting system state, there are two basic methods: state enumeration and Monte Carlo sampling.

Reliability assessment of a composite system generally involves the solution of the network configuration under random outage situations (contingencies). Various techniques, depending upon the adequacy criteria used and the intent behind these studies, are used in analyzing the adequacy of a power system. The three basic techniques used in network solutions are as follows:

- 1) A network flow method
- 2) DC load flow method
- 3) AC load flow method

If the quality of power supply including acceptable voltage levels and appropriate generating unit MVAR limits is an important requirement, more accurate AC load flow methods such as Newton-Raphson, Gauss-Seidel techniques must be utilized to calculate the reliability indices.

The techniques of identifying and analyzing problems in a

system state are the same. These include power flow and contingency analysis for problem recognition and optimal power flow for remedial actions. In our following simulation, the enumeration simulation method is adopted to select system states.

The formulation of load curtailment cost determination under contingency  $S$  using AC load flow and customer interruption load cost and EDRP cost and generation cost can be depicted by the optimization of Equation (6).

$$\text{Min} \{ \text{Cost}(P_{Gi}, Q_{Gi}) + \text{Cost}(P_{EDRP}, Q_{EDRP}) + \text{Cost}(P_{CLC}, Q_{CLC}) \} \quad \text{for } S = 1, 2, 3, \dots, N_c \quad (6)$$

$$P_{gi} - P_{di} + P_{EDRPi} + P_{CLCi} = P_i(\theta, V) \quad i = 1, \dots, n \quad (7)$$

$$Q_{gi} - Q_{di} + Q_{EDRPi} + Q_{CLCi} = Q_i(\theta, V) \quad i = 1, \dots, n$$

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max} \quad i = 1, \dots, n \quad (8)$$

$$Q_{gi}^{\min} \leq Q_{gi} \leq Q_{gi}^{\max} \quad i = 1, \dots, n$$

$$P_{EDRP}^{\min} \leq P_{EDRP} \leq P_{EDRP}^{\max} \quad (9)$$

$$Q_{EDRP}^{\min} \leq Q_{EDRP} \leq Q_{EDRP}^{\max}$$

$$0 \leq P_{CLC} \leq P_{Load} \quad (10)$$

$$0 \leq Q_{CLC} \leq Q_{Load}$$

$$V^{\min} \leq V \leq V^{\max} \quad (11)$$

$$|T| \leq |T^{\max}| \quad (12)$$

$S$ : set of all failure system state.

$N_c$ : Number of system failures.

$\text{Cost}(P_{Gi}, Q_{Gi})$ : is generators cost in power system.

$\text{Cost}(P_{CLC}, Q_{CLC})^3$ : is the customer interruption cost buses under contingency  $S$ .

$\text{Cost}(P_{EDRP}, Q_{EDRP})$ : is the EDRP cost for ISO.

PG and PD are generation output and load power buses vector.

$P_{gi}^{\min}$  and  $Q_{gi}^{\min}$  is the minimum output of power of generators;  $P_{gi}^{\max}$  and  $Q_{gi}^{\max}$  is the maximum output of power of generators vector.

$P_{EDRP}$  and  $Q_{EDRP}$  are EDRP power values vector.

$P_{CLC}$  and  $Q_{CLC}$  are curtailment load values vector.

$V$  is voltage buses vector.

<sup>3</sup> CLC: Customer Load Curtailment

$T$  is power flow on a branch.

$T^{\max}$  is maximum capacity limit of a line or transformer.

This optimal model of load curtailment cost is a problem that is solved by mat power software.

Indices of system reliability are:

EDLC: Expected duration of load curtailment of the overall system:

$$EDLC = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_C} D_{j,i} \right)}{24} \quad (\text{hours / day}) \quad (13)$$

Where

$N_C$  = Number of system interruptions in hour  $i$ .

$D_{j,i}$  = Duration of the  $j$ th system interruption, in hour  $i$ .

LOLP: Loss of load probability of the overall system:

$$LOLP = \frac{EDLC}{24} \quad (\text{occurrence / day}) \quad (14)$$

EDNS: Expected demand not supply of the overall system:

$$EDNS = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_C} DNS_{j,i}^{Sys} \right)}{24} \quad (\text{MW / day}) \quad (15)$$

$DNS_{j,i}^{Sys}$  = System demand not supplied in MW for the  $j$ th interruption, in hour  $i$ .

EENS: Expected energy not supplied, in [MWh/day], is the total amount of energy which is expected not to be delivered to the loads.

$$EENS = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_C} ENS_{j,i}^{Sys} \right)}{24} \quad (\text{MWh / day}) \quad (16)$$

$ENS_{j,i}^{Sys}$  = System energy not supplied in MWh for the  $j$ th interruption, in hour  $i$ .

Indices of load point reliability are:

LPEDLC: Load point expected duration of load curtailment

$$LPEDLC = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_{C,k}} D_{j,i}^k \right)}{24} \quad (\text{hours / day}) \quad (17)$$

$N_{C,k}$  = Number of interruptions occurring in hour  $i$ , at Bus  $k$ .

$D_{j,i}^k$  = Duration of the  $j$ th interruption in hour  $i$  at Bus  $k$ .

LPEDNS: Load point expected demand not supply:

$$LPEDNS = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_{C,k}} DNS_{j,i}^{Busk} \right)}{24} \quad (\text{MW / day}) \quad (18)$$

$DNS_{j,i}^{Busk}$  = Demand not supplied in MW for the  $j$ th interruption, in hour  $i$  at Bus  $k$ .

LPEENS: Load point expected energy not supplied (MWh/day)

$$LPEENS = \frac{\sum_{i=1}^{24} \left( \sum_{j=1}^{N_{C,k}} ENS_{j,i}^{Busk} \right)}{24} \quad (\text{MWh / day}) \quad (19)$$

$ENS_{j,i}^{Busk}$  = Energy not supplied in MWh for the  $j$ th interruption, in hour  $i$  at Bus  $k$ .

#### IV. NUMERICAL RESULTS

In order to show the effect of emergency demand response program on system reliability of a deregulated power system, a case study based on the IEEE 6-bus system is presented in this section. Roy Billinton Test System (RBTS) has 11 generating units, with the total installed capacity of 240 MW and a total system peak demand of 185MW spreading out among 5 system buses. The single line diagram of RBTS is shown in Fig. 2.

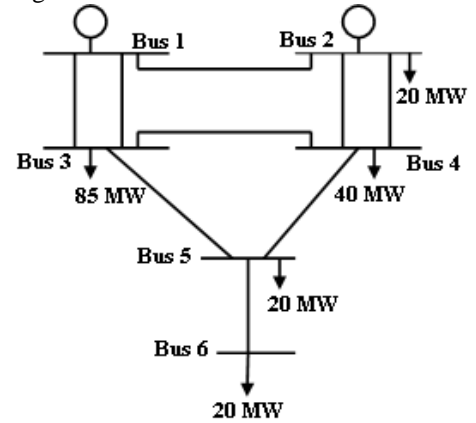


Fig2. Single line diagram of the RBTS

The amount of incentive in EDRP program formulation is assumed to be equal to 500 \$/MWh (existing incentive in New York market). The elasticity of the load is shown in Table1.

TABLE 1. SELF AND CROSS ELASTICITIES

	Peak	Off-Peak	Low
Peak	-0.02	0.0032	0.0024
Off-Peak	0.0032	-0.02	0.002
Low	0.0024	0.002	-0.02

Load curve of Mid-Atlantic region New York network was selected for testing and analyzing the effect of EDRP

program, Fig. 3 [4]. The load curve is divided into three intervals: low load period (12.00 p.m. to 9:00 a.m.), off-peak period (10:00 a.m. to 13:00 p.m. and 19:00 p.m. to 12:00 p.m.) and peak period (14:00 p.m. to 18:00 p.m.).

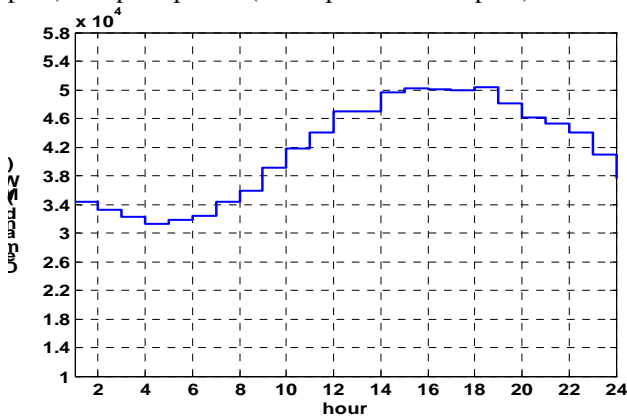


Fig3. Load curve of Mid-Atlantic region New York network

The load curves before and after implementation of emergency demand response program is represented in Fig. 4. As it can be seen, by implementation of emergency demand response program, based on the difference between elasticities in different periods, loads are transferred from peak periods to valley periods. Without emergency demand response program, the IEEE 6-bus system peak load is 315 MW; considering demand response programs, however, the IEEE 6-bus system peak load is 285.64MW.

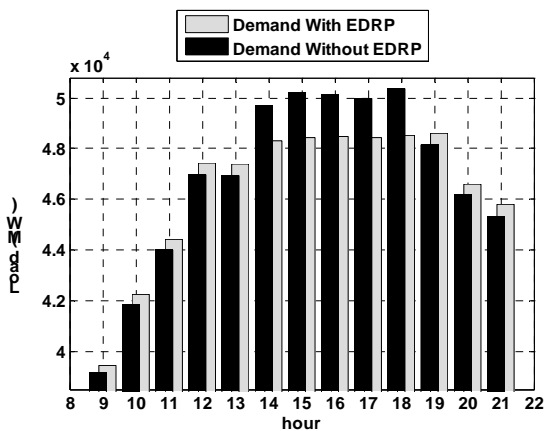


Fig4. Effect of EDRP in Mid-Atlantic load curve

In order to show the effect of emergency demand response program on the load curve and system and nodal reliability of a deregulated power system, the same test system, RBTS, has been simulated using the reliability evaluation techniques. Above program maximize the profit of customers moreover influencing the system and load point reliability.

Two scenarios will be observed in this paper: 1- Test of system without considering emergency demand response program, 2- Test of system with considering emergency demand response program.

The simulation results for the reliability of total system have been shown in Table II.

TABLE II  
SYSTEM RELIABILITY INDICES OF THE RBTS

	Without Considering EDRP	Considering EDRP
LOLP	0.17875	0.135462
EDLC (h)	0.1282	0.0985
EDNS (MW)	942.673	629.626
EENS (MWh)	112.2254	28.1364

For system nodes the results can be seen in Table III, IV, and V.

TABLE III  
LOAD POINT EXPECTED DURATION OF LOAD CURTAILMENT [HOUR]

	Without Considering EDRP	Considering EDRP
Load 6	0.036547	0.031231
Load 3	0.036112	0.035024
Load 4	0.035101	0.035002
Load 5	0.035004	0.034987

TABLE IV  
LOAD POINT EXPECTED DEMAND NOT SUPPLIED (MWH/DAY)

	Without Considering EDRP	Considering EDRP
Load 6	1199.3826	772.2243
Load 3	261.3892	113.3993
Load 4	114.2587	76.8648
Load 5	498.8546	416.0093

TABLE V  
LOAD POINT EXPECTED ENERGY NOT SUPPLIED (MWH/DAY)

	Without Considering EDRP	Considering EDRP
Load 6	63.1254	59.7458
Load 3	29.5468	27.0125
Load 4	27.2548	25.6074
Load 5	34.8546	32.8425

The results show that emergency demand response program improves the reliability of the system. Comparing the nodal reliability indices with and without considering emergency demand response program, it can be seen that the nodal reliability is also improved when emergency demand response program is considered.

## V. CONCLUSIONS

This paper evaluated the effects of demand response programs especially emergency demand response program on system and load point reliability of a deregulated power system using an economic load model, AC power-flow-based load curtailment cost function and reliability evaluation techniques.

In this paper for calculation the reliability indexes, the Emergency Demand Response Program (EDRP) cost is considered and in each contingency state, the EDRP cost with the customer load curtailment cost is compared and the load appropriate value is selected for load



shedding or participating in EDRP. In the next stage, the system and nodal reliability indexes are calculated.

From the simulation results it can be seen that emergency demand response program improves the system reliability and nodal reliability of a deregulated power system.

According to obtained results, EDRP using lead to increasing nodal and system reliability. It can be said that solving problems such as congestion in transmission lines, power system reliability decrease at load network peak hours, is impossible without customer interfering in power market. In other hand Consumer participation, makes the power markets more competition and enhance its performance.

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## VIII. BIOGRAPHIES

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