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Analysis of Price and Incentive Based Demand Response programs on Unit Commitment using Particle Swarm Optimization

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ABSTRACT- The increase in power demand by various infrastructural development activities and industrial automations in recent years have made a vital effect with respect to the load demand. To effectively manage the load demand, several Load Management (LM) techniques has been adopted in all energy policy decisions. In the de-regulated power system, the Demand Side Management (DSM) owing to its advantages at economic environments are regarded as remarkable choice and has been extended to incorporate Demand Response Programs (DRPs) in the load management techniques. In this paper, a responsive load economic model is developed. This model is based on the two factors such as price elasticity of demand and welfare function of customers. A Demand Response (DR) based Unit Commitment (DRUC) problem is studied to execute the economic analysis of DRPs. The main idea behind the DRUC is to maximize the benefit of both customers and utilities. The Particle Swarm Optimization (PSO) technique has been used to resolve the unit commitment problem with and without DRPs. The optimization outcomes are also compared with the conventional methods. To verify the efficacy of the DRUC model, the conventional ten-unit test system is considered. The simulated result shows that Critical Peak Pricing (CPP) and Direct Load Control (DLC) gives the best peak reduction and Time of Use (TOU) gives the best total cost reduction among all the DRPs and the other conventional methods.

Keywords: Demand Response, Unit Commitment, Particle Swarm Optimization, Economic Load Model, price elasticity, Smart grid.

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1. INTRODUCTION

The advancement in Information and Communication Systems and Software technologies have opened up new opportunities to operate the energy supply system in a smart grid environment. In smart grid, Demand Response (DR) is becoming an integral part, which enable the operators to efficiently utilize their resources and have a control over the functioning of the power system. Unit commitment plays a major role in the power system operation and control. The integration of Demand response modeling with unit commitment program would effectively explore the economic and environmental benefits of DR programs. In addition, it determines the load provided by the DRPs, schedule the optimum generation units for satisfying the demand and assess the best incentive price which are the crucial challenges.

Demand Bidding (DB) / Buyback programs and Ancillary Services (A/S) are market clearing programs [10]. DRPs determines the number of load, the customers inclined to reduce at a rate they are willing. In A/S programs, the customers are permitted to offer load curtailment. If their proposals are accepted, then they are paid off the spot market energy cost for assigned to be on reserve stand-by.

2. LITERATURE SURVEY

Based on the benefit function of the customer and load demand, an economic and environmental driven model has been developed by Amir et al [1]. Various researches have used different optimization methods for the analysis of either incentive based or price based DRPs on unit commitment. Govardhan et al [2] have used heuristic methods for the study of price based DRPs on unit commitment. For instance, Javad Nikoukar [3] describes a mechanism for unit commitment using MATLAB tool considering Emergency Demand Response Program (EDRP) and Interruptible / Curtailable load (I/C) where system reliability and cost minimization has been ensured. Economic analysis of load models is necessary to assess the influence of customer's involvement in DRPs. Schweppe et al [4] have assessed the electrical energy cost using the concept of spot pricing. Kirschen et al [5] were the pioneer who have analysed the customer's behaviour based on self and cross elasticities. These elasticities were considered while fixing different prices for the curtailable loads and planning generation. Alami et al [6,7] have shown that the load shape and demand could be changed by modeling the I/C and capacity market programs and developed a method where the prioritizing of DRPs has been done by multi-criteria decision analysis method, so that the customers can attain their maximum benefit. In order to coordinate the customer's benefit with social welfare maximization, Zang et al [8] have established a unit commitment model by the integration of units' operation cost and customer's utility function. Aoyagi et al [9] have examined the minimization of operating cost of unit commitment through neural network algorithm for price based demand response model. Bakirtzis et al [10] have designed a short-term power system scheduling framework with DR for the secure and efficient incorporation of sustainable energy sources. The integration of demand side resources with the power grid encourages and educates the customers to consume the power efficiently and economically [11-12]. Rahiman et al have justified that in the smart grid, only with the co-operation of power generation and demand, the power balance equation can be satisfied. The main goal of the users' is to augment their profit whether they participate in incentive based or price based DRPs Narayana Prasad has made a survey on deterministic, heuristic and stochastic methods to solve the unit commitment problem.

3. DEMAND RESPONSE BASED UNIT COMMITMENT FORMULATION (DRUC)

The Unit Commitment is a technique of scheduling generating units, without violating the operational constraints. The main objective of unit commitment problem is to reduce the power generation cost along with the running cost. The demand response based unit commitment problem increase the profits of the generating company and minimize the price of energy being provided to the customers. The Figure 1. shows the illustration of the proposed DRUC model. The block diagram consists of supply side component which includes N number of generating companies, the Independent system operator (ISO) links the demand-side and supply-side resources to the generation scheduling problem. The ISO communicates to the demand side by providing incentives and penalty. The customers participating in DR are connected to the ISO by means of DRP and the customers who do not participate in DR are directly connected to the ISO.

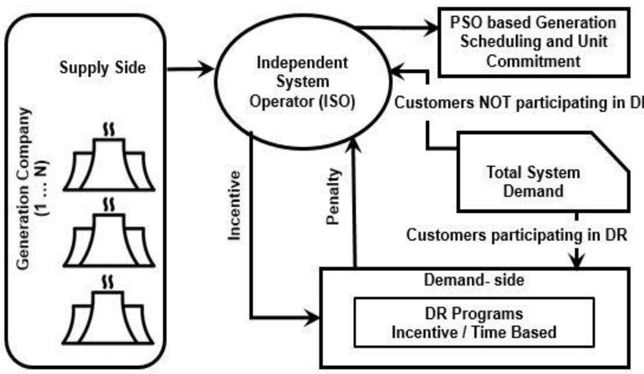


Figure 1: Block Diagram of Demand response based Unit Commitment (DRUC)

A responsive load economic model is designed to assess the effect of customer's contribution on load profile characteristics in DRPs. In the view of spot pricing of electricity, the customers can adjust their demand by increasing or decreasing it. Economic models for TOU, CPP, RTP, EDRP and DLC were formulated by researchers [20] However, I/C and CAP programs were not considered in the formulated models as it includes penalty term.

3.1 Responsive load economic model

This load model describes the behaviour of the customer with respect to the changes in electricity price, the incentives and the penalties imposed [7,23,28].

3.1.1 Price Elasticity of electrical demand

The demand for most commodities decreases as the price increases. The price elasticity is described as the load demand sensitivity with respect to fluctuations in price [5].

$$E = \frac{p_0}{d_0} \cdot \frac{\partial d}{\partial p} \tag{1}$$

Where E is price elasticity of the demand and p_0 is the initial spot electricity price and d_0 is the initial customer's demand. Based on equation (1), the price elasticity of t^{th} period with respect to i^{th} period is defined as [7]

$$E(t,i) = \frac{p_0(i)}{d_0(t)} \cdot \frac{\partial d(t)}{\partial p(i)} \tag{2}$$

3.1.2 Modeling of elastic loads for single period

The implementation of DRPs motivate the customers to change their initial load demand from $d_0(t)$to new load demand $d(t)$ based on the incentive and penalty payments stated in the agreement as

$$\Delta d(t) = d(t) - d_0(t) \tag{3}$$

The customer's demand considering incentive and penalty is obtained as follows [7]

$$d(t) = d_0(t)\left\{1 + E(t,t).\frac{[p(t) - p_0(t) + A(t) + pen(t)]}{p_0(t)}\right\} \tag{4}$$

In the above equation, $d(t) = d_0(t)$ if same tariff is presumed before and after the implementation of DRPs.

3.1.3 Modeling of elastic loads for multi-period

In multi-period modeling as per the explanation of equation (2), the cross elasticity is assumed as constant [4] that is

$$\frac{\partial(t)}{\partial p(i)} \quad : \text{constant for } t, i = 1,2 \ldots 24, \; t \neq i \tag{5}$$

The following equation can be defined by applying the linear relationship between prices and demand as,

$$d(t) = d_0(t) + \sum_{\substack{t=1 \\ t \neq i}}^{24} E(t,i) \frac{d_0(t)}{p_0(i)} \; [p(i) - p_0(i)] \tag{6}$$

The incentive and penalty of the multi-period model can be expressed as [7]

$$d(t) = d_0(t) \left\{1 + \sum_{\substack{i=1 \\ i \neq t}}^{24} E(t,i) \frac{[p(i) - p_0(i) + A(i) + pen(i)]}{p_0(i)}\right\} \tag{7}$$

Hence, the equation (20) can be used to calculate the new load demand of the customer for the multi-period with DRPs.

3.1.4 Load economic model

The responsive load economic model gives information about the impact of customer participation in DRPs and their effect on the load profile. It is formed by combining equations (6) and (7) with participation coefficient (η) of the customers as follows

$$d(t) = \eta d_0(t)\left\{\begin{array}{l} 1 + E(t,t)\dfrac{[p(t) - p_0(t) + A(t) + pen(t)]}{p_0(t)} + \\ \sum_{\substack{i=1 \\ i\neq t}}^{24} E(t,i)\dfrac{[p(i) - p_0(i) + A(i) + pen(i)]}{p_0(i)} \end{array}\right\} \quad (8)$$

With the implementation of DRPs equation (9) shows the amount of load need to be consumed by the customers' to accomplish the maximum gain.

3.2 Demand Response Based Unit Commitment (DRUC) Problem Formulation

3.2.1 Objective function

The main aim of UC problem is to minimize the generation cost along with the operating cost. In this paper, the demand response based unit commitment problem is modeled and the main objective of DRUC problem is to minimize the total cost of the system using different DRPs (time based and incentive based) while satisfying the demand, spinning reserve requirement and other constraints. The $DR_{cost}(t)$ should be included in the total system cost for every scheduled hour. The main objective function is

$$min \sum_{j=1}^{N}\sum_{t=1}^{T}\left[\begin{array}{c} F_j(P_j(t) + \\ STC_j\,(1 - I_j(t-1)) \end{array}\right] \times I_j(t) + DR_{cost}(t) \quad (9)$$

Where T is the total scheduled time duration, N denotes the number of thermal units, $F_j(P_j(t))$ is the fuel cost (F) of the generated power (P) by the j^{th} thermal unit for t^{th} period and $I_j(t)$ is the ON / OFF (1/0) status of the committed generated units. In the equation, $STC_j(t)$ is a start-up cost of thermal unit j over a time period t.

In quadratic polynomial form, the fuel cost in scheduling problems can be written as

$$F_j(P_j(t)) = a_j + b_j\left(P_j(t)\right) + c_j\left(P_j(t)\right)^2 \quad (10)$$

Where a_j, b_j, c_j are the cost coefficients of jth unit.

The start-up cost of jth unit is presented in two ways namely

$$STC_j = \left\{\begin{array}{ll} HSC(j), if\ MDT_j \leq X_{joff} \leq H_{joff} & \\ CSC(j), & if > H_{joff} \end{array}\right\} \quad (11)$$

$$H_{joff} = MDT_j + CSH_j \quad (12)$$

Here, $HSC(j)$ is the hot start- up cost and $CSC(j)$ is the cold start-up cost. MDT_j is the minimum downtime of jth unit , X_{joff} is the time period of unit j being continuously off and CSH_j is the cold start hour of jth unit . The difference between the incentive paid by the utility to the customer and the penalty imposed to the customer over a period can be calculated as

$$DR_{cost}\,(t) = P\big(\Delta d(t)\big) - PEN\,\big(\Delta d(t)\big) \quad (13)$$

3.2.2 Unit Commitment Constraints

3.2.2.1 Equality Constraint

Equality constraint is also known as power balance constraint where the total generated power of each unit at tth hour must be equal to the load demand for that particular hour that is

$$\sum_{j=1}^{N} P_j(t)\ I_j(t) = d_0(t) \quad (14)$$

In the above equation (27), $d_0(t)$ represents the load demand at t^{th} hour

3.2.2.2 Spinning Reserve (SR) constraint

To maintain the stability of the system, the spinning reserve capacity has to be maintained. About 10% of the load demand is assumed as the reserve capacity. This can be written as

$$\sum_{j=1}^{N} P_j(t)\ I_j(t) \geq d_0(t) + SR(t) \quad (15)$$

3.2.2.3. Generation limit constraint

The power generated by jth thermal unit, should lie within the maximum and minimum limit.

$$P_{j\,min} \leq P \leq P_{j\,max} \quad (16)$$

Here, $P_{j\,min}$ and $P_{j\,max}$ are the minimum and maximum power generation limit of unit j respectively.

3.2.2.4. Minimum up / down time constraint

$$X_{j\,on} \geq MUT_j \quad (17)$$

$$X_{j\,off} \geq MDT_j \quad (18)$$

For pre-defined time before any transition, the unit has to remain ON/OFF. Where $X_{j\,on}$ is the time period of unit j which is continually on for a particular period and MUT_j is the minimum uptime of jth unit j.

3.2.2.5 Ramp rate constraint

$$P_j(t) \leq RUP_j \times P_j(t-1) \quad (19)$$

$$P_j(t) \leq RDN_j \times P_j(t-1) \quad (20)$$

The inter-hour generation change in a unit is limited by this ramp rate constraint. RUP_j and RDN_j are ramp up and ramp down limits of generator j respectively.

3.3 Particle Swarm Optimization (PSO) algorithm for DRUC

In order to find the optimized solution, PSO algorithm is employed to solve the DRUC problem. In the PSO, each single solution is a 'bird' in the search space called as particle. The fitness values of the particles are evaluated by the fitness function which is to be optimized (fuel cost). The PSO is initialized with a group of random particles (solution) and then searches for optima by updating generations. In every iteration, each particle is updated by following two 'best' values. The first one is the best solution (fitness) called p_{best}. Another "best" value that is tracked by the particle swarm optimizer is the global best called g_{best}. To determine the position of particle in PSO, let $X_i(t)$ denotes the position of particle i in the search space at time step t. The position of the particle is changed by adding a velocity $V_i(t)$, to the current position.

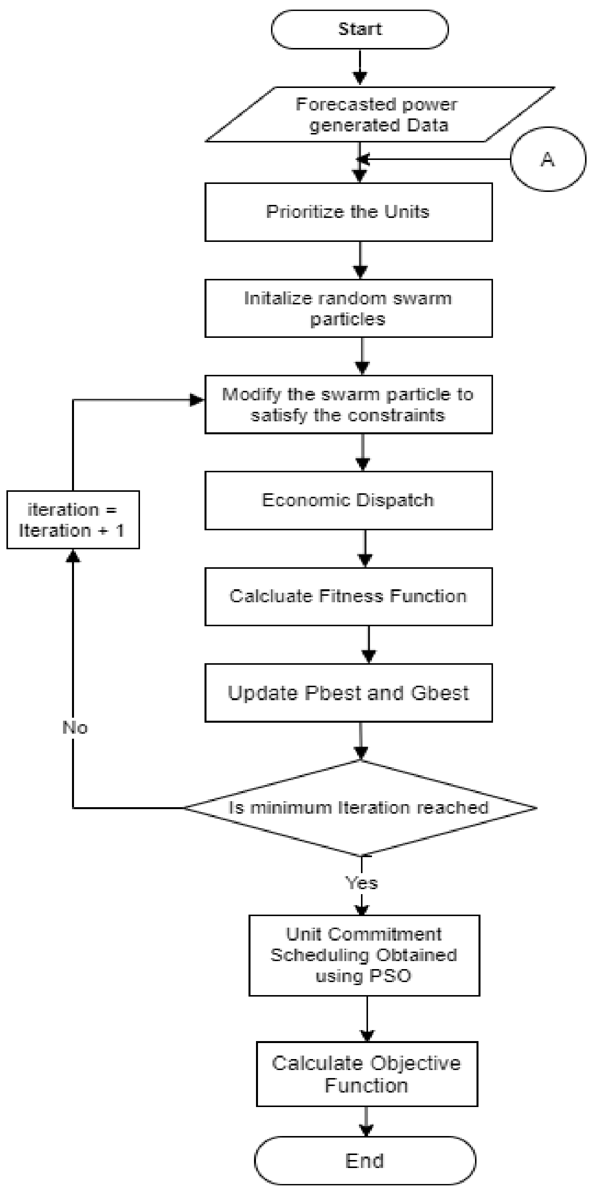
Hence,

$$X_i(t) = X_i(t-1) + V_i(t) \quad (34)$$

The velocity of the particle is determined using the formula

$$V_i(t) = wV_i(t-1) + c_1 r_1 (p_{best} - X_i(t-1)) + c_2 r_2 (g_{best} - X_i(t-1)) \quad (35)$$

Where V_i is the velocity of the i^{th} particle, w is the inertia weight factor of the particle, c_1 and c_2 are acceleration coefficients, r_1 and r_2 are the random numbers ϵ [0,1], p_{best} is the personal best and g_{best} is the global best. The flowchart of PSO algorithm for the DRUC is shown in *Figure 2*. Here appropriate DRPs are applied for the forecasted power generation data then the unit commitment scheduling is done using PSO algorithm. Finally, the objective function of DRUC is calculated.



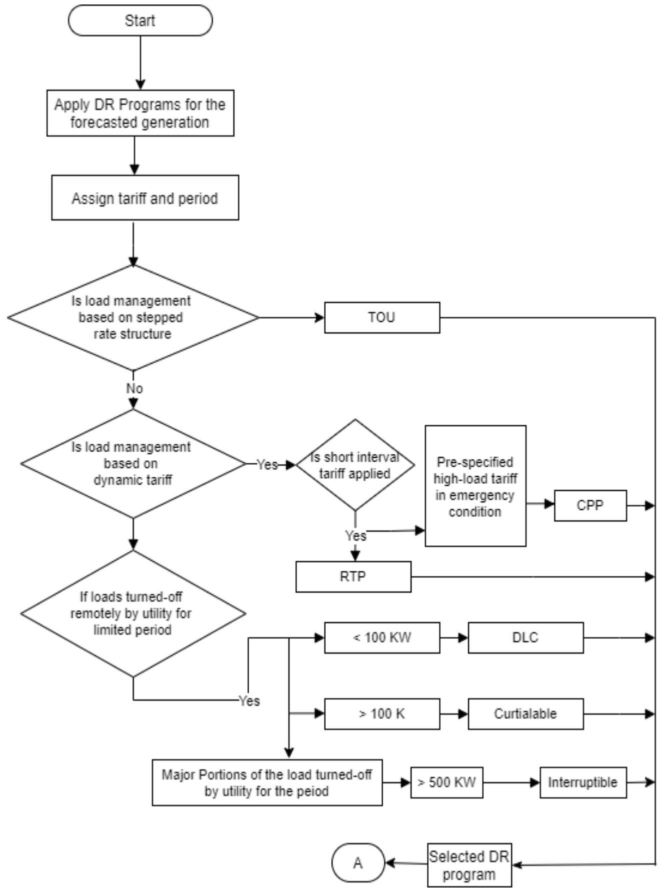


Figure 2: Flowchart of proposed PSO Algorithm for DRUC

4. RESULTS AND DISCUSSION

In this paper, for the evaluation of the developed model IEEE 39 bus system with conventional ten unit has been used for a scheduling period of 24 hours which incorporates different DRPs as described in table 3. The load demand is divided into three periods namely valley period (01:00 to 04:00 hrs and 23:00 to 24:00 hrs), off-peak period (05:00 to 08:00 hrs, 14:00 to 19:00 hrs and 22:00 hr) and peak period (08:00 to 14:00 hrs and 19:00 to 21:00 hrs). The price elasticity demand is shown in table-2 [1]. To perform the simulation, the generating unit's data for the ten-unit test system described in the table 1 are fed as input data for the problem formulation [1].

Table 1. Generating unit's data for the Ten-unit test System

Units	a_j	b_j	c_j	P_{min}	P_{max}	*CSC*	*HSC*	*CSH*	*MUT*	*MDT*
1	1000	16.19	0.00048	150	455	9000	4500	5	8	8
2	970	17.26	0.00031	150	455	10000	5000	5	8	8
3	700	16.60	0.00200	20	130	1100	550	4	5	5
4	680	16.50	0.00211	20	130	1120	560	4	5	5
5	450	19.70	0.00398	25	162	1800	900	4	6	6
6	370	22.26	0.00712	20	80	340	170	2	3	3
7	480	27.74	0.00079	25	85	520	260	2	3	3
8	660	25.92	0.00413	10	55	60	30	0	1	1
9	665	27.27	0.00222	10	55	60	30	0	1	1
10	670	27.79	0.00173	10	55	60	30	0	1	1

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The hourly variation of the electrical load data for the 24-hour study horizon is shown in Figure. 3. The table 3 shows the value of incentive, penalty and spot electricity prices for each implemented DR programs. These programs are divided as base case, TBR and IBP.

Figure 3: Load Demand for 24 Hours

Table 2. Price Elasticity of Demand

Hour	1-5	6-9	10-14	15-19	20--24
1 – 5	-0.08	0.03	0.034	0.03	0.034
6 – 9	0.03	-0.11	0.04	0.03	0.04
10 – 14	0.034	0.04	-0.19	0.04	0,01
15- 19	0.03	0.03	0.04	-0.11	0.04
20 -24	0.034	0.04	0.01	0.03	-0.19

Table 3. Statement of implemented DRPs

No	Program	Spot Electricity Prices ($/MWh)	Incentive ($/MWh)	Penalty ($/MWh)
Base case (Initial Demand)		21 flat rate	0	0
1	DLC	21 flat rate	14	0
2	ILC	21 flat rate	14	0
3			14	21
4	RTP	18,18,19,20,20,22,22,23,32,32,34,35,32,32,23,21,20,22,23,32,32,22,19,18 at 1-24 hours respectively	0	0
5	CPP	42 at 11, 12 hours (Critical Peak Period)	0	0
6	TOU	18,21,35, at Valley period, Off peak and Peak periods respectively	0	0

The simulation results and the effect of considered DRPs on load demand are discussed in the following section.

4.1 Analysis of the Results

The economic analysis is done using various indices such as electrical energy consumption cost, utility revenues and customer's benefit before and after implementing DRPs is shown in table 5. In addition to economical comparison, technical comparison shown in table 6 describes the changes in electrical energy consumption with peak demand reduction for each DRPs.

Table 4. Optimal Generation Scheduling for Ten-unit system using PSO

Hours	Units (MW)									
	Unit1	Unit2	Unit3	Unit4	Unit5	Unit6	Unit7	Unit8	Unit9	Unit10
1	455	245	0	0	0	0	0	0	0	0
2	455	295	0	0	0	0	0	0	0	0
3	455	370	0	0	25	0	0	0	0	0
4	455	455	0	0	40	0	0	0	0	0
5	455	390	0	130	25	0	0	0	0	0
6	455	360	130	130	25	0	0	0	0	0
7	455	410	130	130	25	0	0	0	0	0
8	455	455	130	130	30	0	0	0	0	0
9	455	455	130	130	85	20	25	0	0	0
10	455	455	130	130	162	33	25	10	0	0
11	455	455	130	130	162	73	25	10	10	0
12	455	455	130	130	162	80	25	43	10	10
13	455	455	130	130	162	33	25	0	10	0
14	455	455	130	130	85	20	25	0	0	0
15	455	455	130	130	30	0	0	0	0	0
16	455	310	130	130	25	0	0	0	0	0
17	455	260	130	130	25	0	0	0	0	0
18	455	350	130	130	25	0	0	10	0	0
19	455	455	130	130	30	0	0	0	0	0
20	455	455	130	130	162	33	25	10	0	0
21	455	455	130	130	85	20	25	0	0	0
22	455	340	130	130	0	20	25	0	0	0
23	455	315	130	0	0	0	0	0	0	0
24	455	345	0	0	0	0	0	0	0	0

4.1.1 Base Case

The first row of table 5 and 6 shows the actual load without DRPs. The total demand for this case is 27100 MW with the peak value of 1500 MW. The table 4 shows the scheduling of generating units for this case with the total cost of $ 565230.

4.1.2 Program -1

In this program, during the peak period the customers tend to curtail their load when the electricity price increases above the average price. The spot electricity prices and incentives are considered as shown in table 3. The system total load is now 26700 MW with peak value reduced to 1400 MW compared to base case.

4.1.3 Program -2

In this case, the load profile characteristics and customer's benefit are improved after the implementation of I/C program. Here, the interruption for peak hours is assumed at 9,10,11,12,13,14,20 and 21 hours. For the load reduction of 585 MW, the total incentive provided by the utility is $ 8208.

4.1.4 Program -3

In this case, the customers are imposed with the penalty of $ 21/ MWh if they fail to curtail their load as per the contract. Here, compared to the base load the total demand is reduced to 26573 MW with peak reduction of 4.3% and total operating cost has been reduced to $ 556257.

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Table 5A. Economical comparison of Programs

No	Program	Operating Cost($)	Start-up Cost($)	Incentive ($)	Penalty ($)	Total Cost ($)
Base case (Initial Demand)		**561110**	**4120**	**_**	**_**	**565230**
1	DLC	553769	4140	5612	-	563521
2	ILC	544100	4290	8208	-	555756
3		545384	4700	7394	1221	556257
4	RTP	549088	4550	_-	_-	553638
5	CPP	553612	4060	-	-	557672
6	TOU	540778	4500	-	-	545278

4.1.5 Program -4

In this time based DR program, the customers are neither awarded incentives nor penalized. In this case, the total load demand is decreased to 26721 MW with system peak of 1459 MW.

Table 5B. Economical comparison of PSO with other Conventional Methods

Sl No	Methods	Total Cost in ($)
1	UC - Lagrangian Relaxation(LR) [19]	565825
2	UC - Binary-Coded Genetic Algorithm BCGA [20]	567367
3	UC- Integer-Coded Genetic Algorithm (ICGA) [20]	566404
4	UC - Bacterial Foraging Algorithm (BFA) [21]	565872
5	UC - PSO	565230
	UC- PSO with DR Programs	
7	UC – PSO with DLC	563521
8	UC – PSO with ILC (1)	555756
9	UC – PSO with ILC (2)	556257
10	UC – PSO with RTP	553638
11	UC – PSO with CPP	557672
12	UC – PSO with TOU	545278

4.1.6 Program -5

In CPP program, the price of $ 42 is considered for 11th and 12th hr (critical peak hours). Table 5 and 6, show that the load profile has been improved during critical a peak hour and the power consumption is also reduced to 26898 MW. The Figure 4 shows that the total operation cost of UC problem using PSO with DR programs are better than the base case as well as the conventional unit commitment methods

4.1.7. Program -6

As shown in table 5A and 6 the TOU rates used are high during peak period so utmost demand reduction is attained and hence the total system cost is also reduced to $ 545278 which is the least of all DRPs.

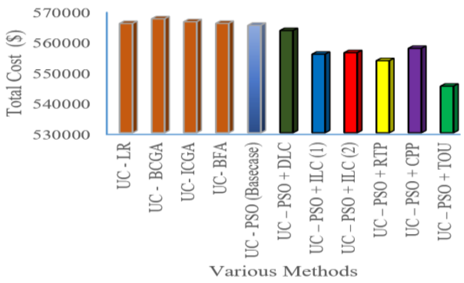

Figure 4: Cost Comparison of TUC and UC- PSO (Base case) with DR

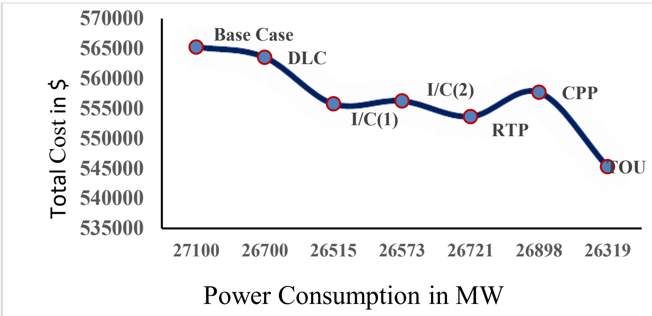

Figure 5: Power Consumption (MW) vs Total Cost ($)

Table 6. Technical Comparison of Programs

No	Program	Power Consumption (MW)	Load Reduction (MW)	Load Reduction(%)	Peak Value (MW)	Peak Reduction(%)
Base case (Initial Demand)		27100	0	0	1500	0
1	DLC	26700	400	1.47	1400	6.6
2	ILC	26515	585	2.15	1431	4.6
3		26573	527	1.94	1435	4.3
4	RTP	26721	379	1.39	1459	2.7
5	CPP	26898	202	0.7	1400	6.6
6	TOU	26319	781	2.88	1433	4.4

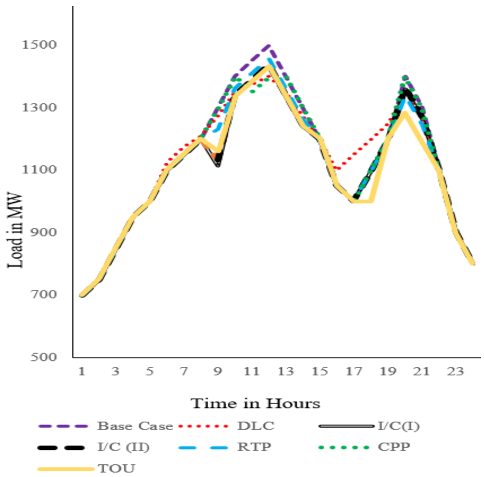

Figure 6: Impact of DRPs on load profile

Figure 5 reflects the influence of the developed DRPs on the load profile of the system. The utmost peak reduction is attained for DLC with an incentive of $14 / MWh and also for CPP compared to the base case. The maximum reduction in energy consumption and total operating cost of the system is achieved in the TOU program as shown in *figure 6*. Hence it is observed that the PSO based DRUC has provided the maximum benefit for the customers and the utilities.

5. CONCLUSION

In this paper, an economic model for different DRPs has been presented. It has been observed that the customer's demand is influenced by the price elasticity of the demand, electricity price, incentive and penalty values determined for the specific DRPs. Here, PSO based unit commitment associated with DRPs (DRUC) has been used. The unit commitment DR model with PSO, reduce the total cost of the system using the optimum scheduling status of generating units. The proposed DRUC model has been illustrated using a ten-unit test system. The UC problem using conventional methods such as LR, BCGA, ICGA, BFA are compared with PSO model. The comparison shows that the total operating cost of UC using PSO is less than the other conventional methods.

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