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Computational Algorithms for the Solution of Economic Load Dispatch in an Interconnected Power System

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Abstract: *The availability of a reliable and low cost electric power is a primary requirement for the rapid development of any nation. The cost of production of electric power is a very important index in national development. Pricing of electricity is a function of the cost of operation of the power system itself. On the generation sector, production costs are mostly in the form of fuel costs which comprise about eighty to ninety percent of the total operation cost. Minimization of costs is necessary so as to keep prices as low as possible. Minimization of costs or optimization of operation can be done through economic load dispatch alongside unit commitment. Use of these concepts should be done in order to obtain a desirable condition. Lagrange Relaxation has become one of the best solution methods in solving the economic load dispatch problems.*
Keywords: *Economic efficiency, Economic Load Dispatch, Incremental Cost*

I. Introduction

The efficient and optimum economic operation of electric power system has always occupied an important position in electric power industry. In recent decades it is becoming very important for utilities to run their power system with minimum cost while satisfying their customers demand all the time and trying to make profit. With limited availability of generating units and large increase in power demand ,fuel cost and supply limitation, the committed units should serve the expected load demand with the changes in fuel cost and the uncertainty in the load demand forecast in all the different time intervals in an optimal manner. The basic problem is to be able to meet the demand with the minimum possible cost.

In order to have most economic operation and ensure optimum utilization, it becomes necessary to operate various power plants located in region in an integrated system. For this purpose all the power plants are connected together and centrally supervised and controlled. The proper coordination of the generation of electrical power in a group of power plants connected to a common grid system leads to considerable saving as compared with the same loads fed from a number of independent power plants. First of all, it enables the total generating capacity to be reduced, since less spare capacity is required, secondly, it allows the system to be planned so that the maximum size generating unit is installed and thirdly, it enables the power plant to be loaded so that the minimum amount of fuel is consumed by concentrating generation in most efficient power plants (Galpter 1995).

Economic dispatch is defined as the process of allocating generation levels to the generating units in an interconnected power system, so that the system load is supplied entirely and most economically. It is a useful tool in power engineering field to ensure that the best electrical and financial performance can be attained. The objective of the economic dispatch problem is to calculate the output power of every generating unit so that all demands are satisfied at minimum cost, while satisfying different technical constraints of the network and the generators. In this problem, the generation costs are represented as curves and the overall calculation minimizes the operating cost by finding the point where the total output of the generators equals the total power that must be delivered.

II. Economic Load Dispatch

Economic load dispatch is defined as the process of allocation generation levels to the on-line units so that systems load may be supplied entirely and most economically. Since the utility owned all the generation, transmission and distribution systems, all planning, operating and controlling could be centralized and performed only by the system controller (Wood, Allen J. & Wollenberg, Bruce F., 1996). Generators submitted cost curves to the system controller, and the system controller used a minimization process to dispatch the least expensive plant first. It is normally assumed the relationship between fuel input (F) and power output (P) can be express with an equation of the form:

$$F_i = a_i + b_i P_i + c_i P_i^2 \quad \ldots\ldots (4.0)$$

The fuel cost function of generator that is usually used in power system operation and control problem is represented with a second-order polynomial as shown in equation.4.0 Where a_i, b_i and c_i are non-negative constants of i^{th} generating unity. Incremental cost can be determined by taking the derivative of the equation 4.0

$\frac{\partial F_i}{\partial P_i}$ = b + 2c P_i -------------------------------6.0

λ = b + 2c P_i --------------------------------- (7.0)

So that Pi = $\frac{\lambda - b_i}{2c_i}$ ------------------------------ (8.0)

Subject to $P_{min} \le P_i \le P max$ -------------------- (9.0)

Sum up the entire Pi for the power system

i.e. $\sum_i^N P_i$ i=1 to N ------------------------- (10.0)

$P_D = \sum_i^N P_i$ ------------------------------------- (11.0)

Or $P_D - \sum_i^N P_i \le \varepsilon$ ----------------------------- (12.0)

Where $\varepsilon = 10^{-5}$ .If conditions in equation (3.0) are met, then Sum up all the Pi(s)

i.e. $\sum_i^N P_i$ ---------------------------- (12.0)

Error = Abs ($\sum_i^N P_i$ - P_D) -------------- (13.0)

Error = $\le \varepsilon$ -------------------------------- (14.0)

If convergence is not achieved then modify λ and recomputed P_i , the process is continued until $P_D - \sum_i^N P_i$ is less than a specified accuracy or $P_D = \sum_i^N P_i$

If convergence is achieved then, compute the following

1. F_i = a + b P_i + c P_i^2
2. P_i for each unit

III. Computational Algorithms

Step1. Total power demand would be given.

Step2. Assign initial estimated value of λ (0).

Step3. Let ε be equal to 10^{-5}.

Step4. F_i For all the units would be given.

Step5. Differentiate F_i with respect to Pi ($\frac{\partial F_i}{\partial P_i}$ = bi + 2ci P_i =λ)

Step6. Re arrange $\frac{\partial F_i}{\partial P_i}$ (so that Pi = $\frac{\lambda - b_i}{2c_i}$)

Step7. Compute the individual Units P1, P2…Pn corresponding to λ (0).

Step8. Compute $\sum_{i}^{N} P_i$

Step9. Check if the relationship ∑Pi (0) =PD is satisfied or $P_D - \sum_{i}^{N} P_i \leq \varepsilon$

Step10. If the summation is less than total power demand, then assign a new value λ (1) repeat steps 8 and 9.
Step11.If the summation is less than the demand, then assign a new value λ (2) and repeat steps 8 and 9. Continue the iteration until when it will converge when

$$\sum P_n = PD \text{ or } P_D - \sum_{i}^{N} P_i \leq \varepsilon$$

12 Calculate fuel cost of each generating unit.

IV. Analysis Of The Viability Of Generating Units

Economic efficiency measures how resources are used in relation to the quantity of electric power produced. Economic Efficiency=Fuel Cost/Power generated (N/MWHr)

V. Cigre Test System

This system has 14 units, 14 buses and 10 lines. Units Cost data and system load demand are give respectively in Table 1.0 and 2.0

Table 1.0.Units costs data for the CIGRE Test system

Units	A (N/Hr)	B(N/MWHr)	C(N/MW^2 Hr)	Min Power (Mw)	Max Power (Mw)
1	155.48	0.489	0.00393	80	300
2	26.025	1.513	0.00602	40	160
3	79.339	0.0678	0.00773	40	160
4	168.56	0.394	0.00393	80	300
5	39.85	1.367	0.0623	40	120
6	63.755	0.675	0.01033	40	150
7	59.406	0.803	0.00966	80	360
8	147.91	0.395	0.00443	80	360
9	144.51	0.538	0.00407	80	360
10	123.73	0.773	0.0034	80	360
11	122.41	0.768	0.0035	80	360
12	137.77	0.623	0.00384	80	360
13	66.876	0.636	0.010008	40	160
14	63.36	0.696	0.00978	40	120

Table 2.0: The load Demand for the CIGRE Test system

Hour (Hr)	Power Demand (MW)	Hour (Hr)	Power Demand (MW)
0100HRS	2000	1300HRS	2820
0200HRS	2030	1400HRS	2885
0300HRS	2060	1500HRS	2945
0400HRS	2110	1600HRS	3000
0500HRS	2170	1700HRS	3030
0600HRS	2240	1800HRS	3100
0700HRS	2330	1900HRS	3150
0800HRS	2420	2000HRS	3240
0900HRS	2505	2100HRS	3300
1000HRS	2590	2200HRS	3240
1100HRS	2670	2300HRS	3120
1200HRS	2750	2400HRS	3005

VI. Aep 30 Bus System

This system has 6 units and 41 lines. Table3.0 shows the units cost data and Table 4.0 shows the load demand. Fig 4.1 shows the network diagram.

Table 3.0.Units costs data for the AEP system

Unit	Pmin	Pmax	A (N/Hr)	B (N/MWHr)	C (N/MW^2 Hr)
1	100	500	240	4	0.007
2	50	600	200	9	0.0095
3	80	800	220	5.7	0.009
4	50	500	200	11	0.009
5	50	650	220	9.8	0.008
6	5	300	190	13	0.0075

Table 4.0: The Load Demand of AEP system

Hour (Hr)	Power Demand (MW)	Hour (Hr)	Power Demand (MW)
0100HRS	1600	1300HRS	3600
0200HRS	1800	1400HRS	3800
0300HRS	2000	1500HRS	4000
0400HRS	2200	1600HRS	2200
0500HRS	2300	1700HRS	2300
0600HRS	2400	1800HRS	2400
0700HRS	2500	1900HRS	2500
0800HRS	2600	2000HRS	2600
0900HRS	2800	2100HRS	2800
1000HRS	3000	2200HRS	3000
1100HRS	3200	2300HRS	3200
1200HRS	3400	2400HRS	3400

6.0.1. Simulation And Test Cases

All the following cases are simulated in the power systems analysis software. In this section, Economic Load Dispatch computational algorithms are used to analyze the following cases.

1. **Case A**: Advantages of power pooling.
2. **Case B**: Impact of generator outage.
3. **Case C**: Effect of varying demand side load.
4. **Case D**: Effect of unit commitment.

Cases A to C are based on the CIGRE system while Case D is based on the AEP system. The AEP and CIGRE systems are tested for different cases.

6.0.2 Case A: Advantages Of Power Pooling

Table 5.0 shows when the generators are dispatched individually so that different power are allocated to different generators and power demand can be met irrespective of the fuel cost/operational cost., the table also shows the fuel consumption for each power generated when all the units are dispatched in a power pool.

Table5.0: Advantage of power pool

Time (Hr)	Total power generated/ demand(MW)	Fuel cost Of Individual (N/HR)	Fuel cost by Power Pooling (N/HR)	Fuel cost Saved (N/HR)	Economic efficiency by pooling units (N/MWHR)	Economic Efficiency Of individual Units (N/MWHR)
0100HRS	2000	4199.79397	4198.68	1.11397	2.09934	2.0999
0200HRS	2030	4269.87697	4265.556	4.32097	2.10126	2.1034
0300HRS	2060	4347.03397	4333.146	13.8877	2.10347	2.1102
0400HRS	2110	4473.95346	4447.371	26.58246	2.10776	2.1204
0500HRS	2170	4635.71346	4587.042	48.67146	2.11384	2.1363
0600HRS	2240	4806.20036	4753.585	52.61536	2.12214	2.1456
0700HRS	2330	5037.11336	4973.392	63.72136	2.1345	2.1619
0800HRS	2420	5339.79236	5199.589	140.20336	2.14859	2.2065
0900HRS	2505	5548.07616	5419.091	128.98516	2.16331	2.2148
1000HRS	2590	5829.7446	5644.292	185.4526	2.17926	2.2509
1100HRS	2670	5984.20766	5861.454	122.75366	2.1953	2.2413
1200HRS	2750	6232.7276	6083.667	149.0606	2.21224	2.2664
1300HRS	2820	6446.4856	6282.246	164.2396	2.22775	2.2859
1400HRS	2885	6619.8242	6470.102	149.7222	2.24267	2.2946
1500HRS	2945	6811.2662	6646.466	164.8002	2.2567	2.3128

1600HRS	3000	6997.4136	6810.629	186.7846	2.27021	2.3324
1700HRS	3030	7079.544	6901.18	178.364	2.27762	2.3365
1800HRS	3100	7317.344	7115.223	202.121	2.295233	2.3604
1900HRS	3150	7555.798	7270.479	285.319	2.3080886	2.3987
2000HRS	3240	7945.662	7554.912	390.75	2.331763	2.4524
2100HRS	3300	8118.398	7748.083	370.315	2.347904	2.4601
2200HRS	3240	7945.662	7544.912	400.75	2.328676	2.4524
2300HRS	3120	7478.641	7177.089	301.552	2.300348	2.397
2400HRS	3005	7028.0061	6825.672	202.3341	2.271438	2.3388
Total	**64710**	**148048.28**	**144113.858**	**3934.42**	**53.1394**	**54.4796**

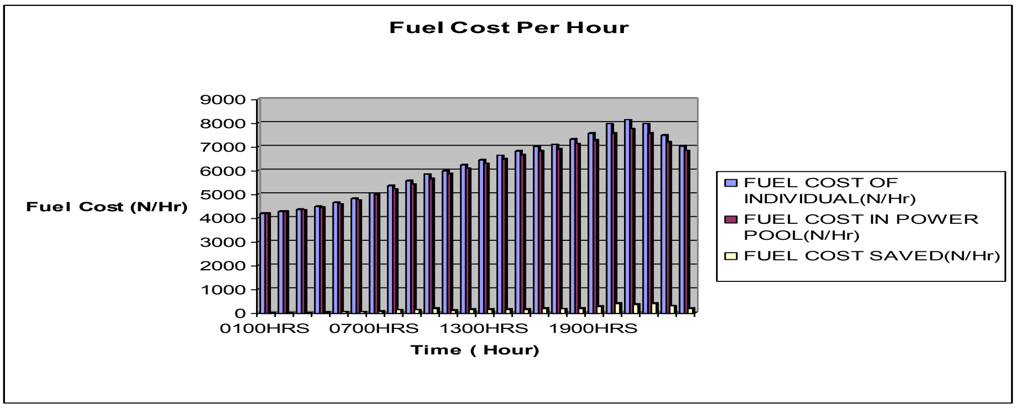

Fig 2.0: Fuel Cost per hour

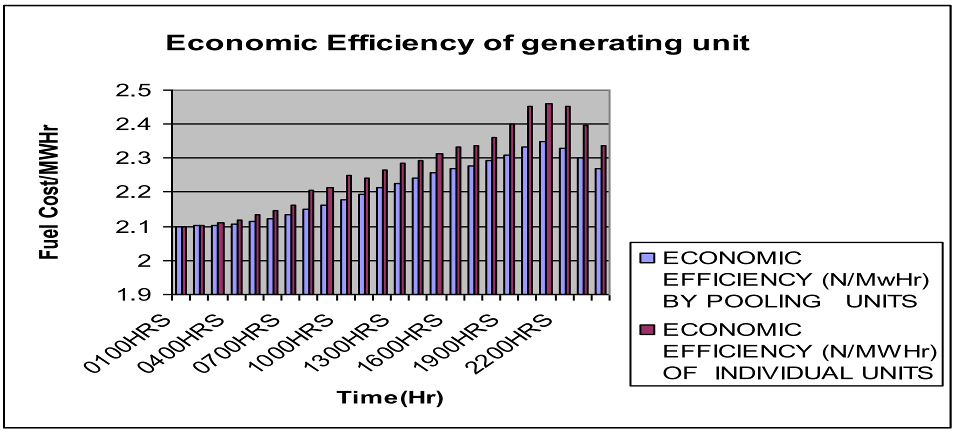

Fig 3.0: Economic Efficiency of generating unit

13.2 Results for case A

Total Fuel Cost per day by using power pool=144113.858N/Hr
Total Fuel Cost per day by individual unit= 148048.2786N/Hr
Total Fuel Cost Saved = 148048.2786-144113.858N/Hr
3934.42N/Hr
Total Fuel cost saved per day = 94426.0944 N/day
Net Profit of 34465524.46 N/Annum

% saving in Total Cost per hour = $\frac{3934.42}{144113.858} \times 100\%$ = 2.73%

Total Fuel Cost /MWHr by using power pool=53.1394 N/MWHr
Total Fuel Cost /MWHr by individual unit= 54.4796N/MWHr
Total Fuel cost saved per MWHr = N1.3402/ MWHr

% saving in Total fuel cost per MWHr= $\frac{54.4796 - 53.1394 x 100\%}{53.1394}$

$$= \frac{1.3402 x 100\%}{53.1394}$$

=2.522%

It can be observed from the results that 2.73% saving in the total fuel cost or 2.522% in N/ MWHr can be achieved in one hour. Which means, for one whole day the total costs of more than 90000 N/Hr or N1.3402/ MWHr has been saved. The proposed techniques and approach give better results in terms of costs optimization. In this case, it can be clearly proved that applying the optimal solution techniques can lead to remarkable cost optimization and increase profits for generation companies. From the results in Table 5.0, we can see that if the system is dispatched together or as a "pool", there is a saving in total cost. After this type of centralized dispatch is implemented, the savings can be split among the generating entities in the pool. This is one of the main advantages of trading energy by a power pool based system.

6.0.3 Case B: Impact Of Generator Outage

This case examines the cumulative effect of generator outages. In this case some generators were simulated to have no output as it can be seen below; the input data for this case is shown in Table 3.0 .The results of the dispatch of this system are shown in table 6.0.Also the table 6.0 shows the fuel consumption for each generating unit if there is power outage and fuel cost saved.

Table 6.0: Fuel cost saved.

Time (Hr)	Total Power Generated /demand (MW)	Fuel cost with outage units(N/HR)	Fuel cost Without Outage (N/HR)	Fuel cost Saved (N/HR)	Economic Efficiency With outage N/MWHr	Economic Efficiency Without Outage N/MWHr
0100HRS	2000	4234.124	4198.68	35.444	2.117062	2.09934
0200HRS	2030	4342.325	4265.556	76.769	2.139078	2.10126
0300HRS	2060	4532.721	4333.146	199.575	2.20035	2.10347
0400HRS	2110	4673.991	4447.371	226.62	2.21516	2.10776
0500HRS	2170	4847.01	4587.042	259.968	2.23365	2.11384
0600HRS	2240	5053.684	4753.585	300.099	2.25611	2.12214
0700HRS	2330	5327.032	4973.392	353.64	2.28628	2.1345
0800HRS	2420	5608.957	5199.589	409.368	2.317751	2.14859
0900HRS	2505	5883.097	5419.091	464.006	2.34854	2.16331
1000HRS	2590	6164.888	5644.292	520.596	2.38027	2.17926
1100HRS	2670	6437.093	5861.454	575.639	2.4109	2.1953
1200HRS	2750	6716.074	6083.667	632.407	2.44221	2.21224
1300HRS	2820	6965.744	6282.246	683.498	2.47012	2.22775
1400HRS	2885	7202.227	6470.102	732.125	2.49644	2.24267
1500HRS	2945	7424.488	6646.466	778.022	2.52105	2.25686
1600HRS	3000	7621.58	6810.629	810.951	2.54052	2.27021
1700HRS	3030	7745.887	6901.18	844.707	2.5564	2.27762
1800HRS	3100	7876.259	7115.223	761.036	2.54073	2.29523
1900HRS	3150	8066.139	7270.479	795.66	2.560679	2.30809
2000HRS	3240	8414.369	7554.912	859.457	2.59703	2.33176
2100HRS	3300	8651.127	7748.083	903.044	2.621554	2.347904
2200HRS	3240	8414.369	7544.912	869.457	2.59713	2.32868
2300HRS	3120	7951.903	7177.089	774.814	2.54869	2.30035
2400HRS	3005	7522.532	6825.672	696.86	2.50333	2.27143
TOTAL	**64710**	**157677.62**	**144113.858**	**13563.762**	**57.901034**	**53.13956**

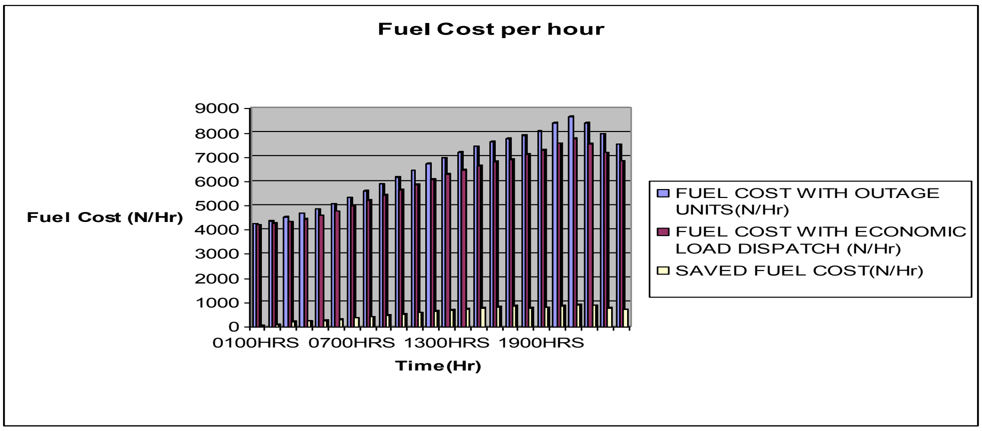

Fig.4.0: Power generated vs. fuel cost

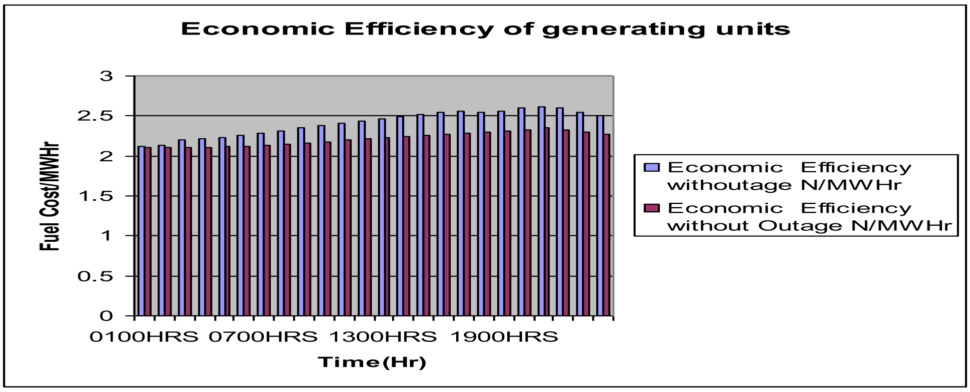

Fig.6.0: Economic Efficiency of generating units

6.0.4 Results For Case B

In this case, it can be seen that the cumulative effect of having multiple problems with a power system can lead to devastating effects to the electricity market. The system operating cost increases by 90%. Table 6.0 and fig4.0 show the impact of Generator Outage in any integrated power system. Total Fuel Cost per day by pooling two or more generators together without outage from any unit=144113.858N/Hr

Total Fuel Cost per day by pooling two or more generators together with outage from some units = 157677.62N/Hr

Total Saved Fuel Cost = 157677.62N/Hr -144113.858N/Hr

13563.76N/Hr

% saving in Total Cost per hour = $\frac{13563.76 \text{ x } 100\%}{144113.858}$ = 9.412%

Incremental cost with out outage= 40.31156N/MWHr

Incremental cost with outage=42.438227N/Hr

% saving in incremental Cost = $\frac{42.438227\text{-}40.31156 \text{ x } 100\%}{40.31156}$

=5.28%

Total Fuel Cost /MWHr without outage=40.31156 N/MWHr

Total Fuel Cost /MWHr with outage = 42.438227N/MWHr

Total Fuel cost saved per MWHr = N4.7054/MWHr

% saving in N/MWHr = $\frac{57.901034 - 53.1956x100\%}{53.1956}$

$= \frac{4.705434x100\%}{53.1956}$

=8.845%

It can be observed from the results that 9.412% saving in the total cost and 8.845% in N/MWHr can be achieved per day. That means, for one whole day the total costs of more than 13000N/Hr or 4.7054N/MWHr has been saved. The generator outage of any unit is not only raised the system fuel cost/MWHr by about 8.845% but also increased the total operating costs of all the other generating entities by about 9.4%.The proposed techniques and approach give better results in terms of costs optimization. In this case, it can be clearly proved that applying the optimal solution techniques can lead to remarkable cost optimization and increase profits for generation companies.

6.0.5 Case C: Effect Of Varying Demand-Side Load

In this case, the load that was constant for all the above cases at 2000 MW is varied from 2000MW to 3300 MW. The dispatch of various values of load was conducted in Table 7.0.

Table 7.0: The effect of varying Demand-side Load

Time (HR)	Total power generated/demand (MW)	Fuel cost(N/HR)	Incremental cost(N/MWHR)
0100HRS	2000	4198.68	2.217412
0200HRS	2030	4265.556	2.24108
0300HRS	2060	4333.146	2.264756
0400HRS	2110	4447.371	2.30421
0500HRS	2170	4587.042	2.351554
0600HRS	2240	4753.585	2.40679
0700HRS	2330	4973.392	2.477806
0800HRS	2420	5199.589	2.548823
0900HRS	2505	5419.091	2.615895
1000HRS	2590	5644.292	2.682966
1100HRS	2670	5861.454	2.746092
1200HRS	2750	6083.667	2.80912
1300HRS	2820	6282.246	2.864453
1400HRS	2885	6470.102	2.915743
1500HRS	2945	6646.466	2.963087
1600HRS	3000	6810.629	3.006486
1700HRS	3030	6901.18	3.030159
1800HRS	3100	7115.223	3.085394
1900HRS	3150	7270.479	3.124847
2000HRS	3240	7554.912	3.195865
2100HRS	3300	7748.083	3.243209
2200HRS	3240	7544.912	3.195865
2300HRS	3120	7177.089	3.101176
2400HRS	3005	6825.672	3.010432

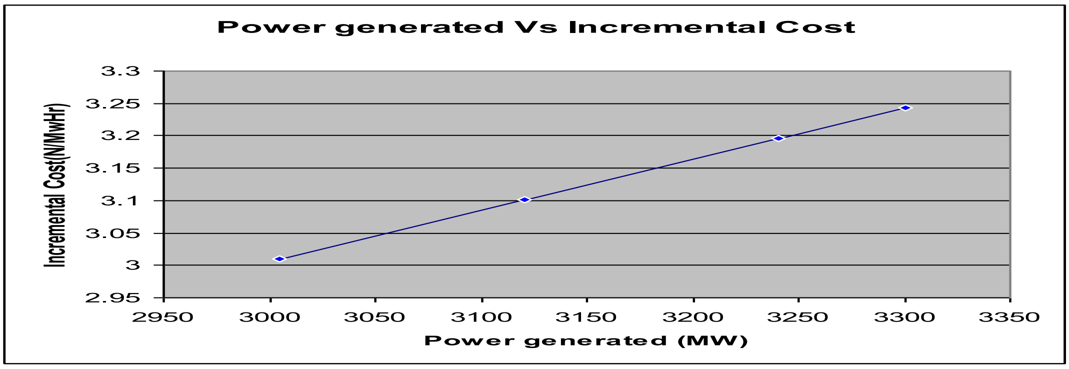

Fig 8.0: Power generated Vs incremental Cost

6.0.6 Results For Case C

The results for the system incremental cost and operating cost were plotted for the various load levels. From figure 8.0, it is observed that operating rises linearly to incremental cost with ascending load values. Therefore, it can be concluded that operating costs and the system incremental cost λ are directly proportional to the demand load. They follow an approximately linear trend in relation to the changing load. Table 7.0 and fig 8.0 show that operating cost and incremental costs are directly proportional to the demand load in any integrated power system. It has been found that the value of fuel cost has significant impacts on the total amount of power dispatched and overall cost of operation. It can be noted that the power dispatch depends on the cost of fuel when the cost of fuel in the system is low, the power dispatched increases significantly i.e. Fuel cost is directly proportional to the power dispatched by each power generating station.

6.0.7 Case D: Effect Of Unit Commitment

In this section the effect of the type of dispatch used on unit commitment is examined in a deregulated marketplace. The test case used here is based on an example from Saadat with a few minor changes and is based on the AEP system with data in Table 8.0

Table 8.0: The fuel consumption and fuel cost saved per hour

Time (Hr)	Total Power Generated (MW)	Fuel cost Without Considering Unit Commitment (N/Hr)	Fuel cost by applying unit Commitment (N/Hr)	Fuel cost saved (n/hr)	Economic Efficiency Without Unit Commitment (N/MWHr)	Economic Efficiency With unit Commitment (N/MWHr)
0100HRS	1600	16845.93	16606.9	239.03	10.52871	10.3793125
0200HRS	1800	19517.26	19406.03	111.23	10.8429	10.78113
0300HRS	2000	22298.39	22165.2	133.19	11.149195	11.0826
0400HRS	2200	25189.3	25121.27	68.03	11.44968	11.41876
0500HRS	2300	26675.93	26649.69	26.24	11.59823	11.58682
0600HRS	2400	28190	28190	0	11.74583	11.7458
0700HRS	2500	29731.52	29731.52	0	11.89261	11.892608
0800HRS	2600	31300.49	31300.49	0	12.03865	12.03865
0900HRS	2800	34520.77	34520.77	0	12.32885	12.32885
1000HRS	3000	37850.83	37850.83	0	12.6169433	12.6169433
1100HRS	3200	41290.68	41290.68	0	12.90333	12.9033375
1200HRS	3400	44840.31	44840.31	0	13.188326	13.18832
1300HRS	3600	48499.75	48499.75	0	13.47215	13.472152
1400HRS	3800	52268.97	52268.97	0	13.754992	13.755
1500HRS	4000	56147.96	56147.96	0	14.03699	14.03699
TOTAL	**41200**	**515168.1**	**514590.4**	**577.7**	**183.5473863**	**183.2272733**

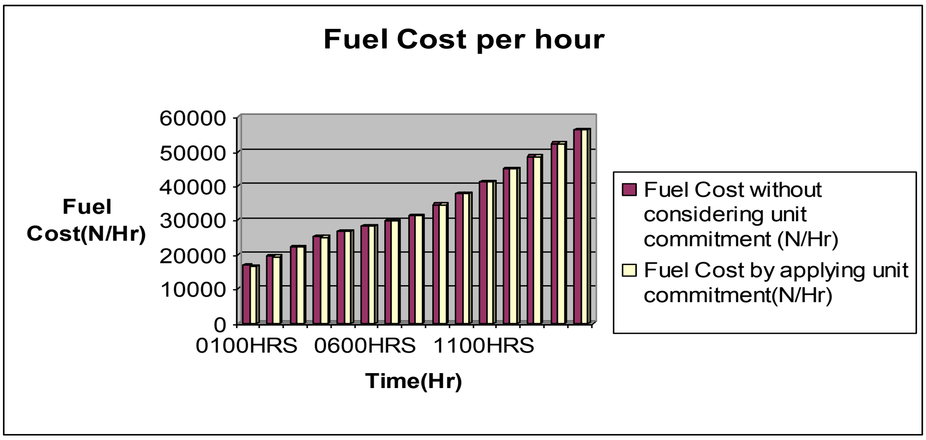

Fig 9.0: Fuel cost per hour

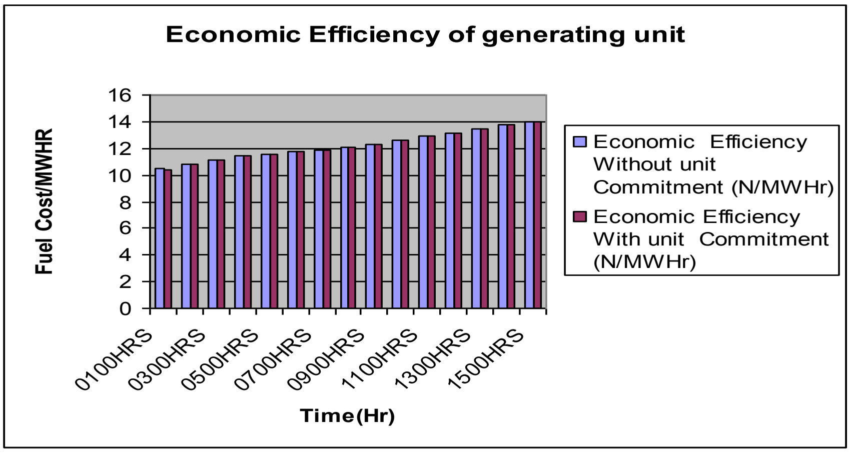

Fig 10.0: Economic Efficiency of generating unit

6.0.8 Results For Case D: Effect Of Unit Commitment On Power System

From the analysis the base load generating units are 1, 2, 3 and 5 based on their low fuel consumption while peak load generating units are 4 and 6.

Table 9.0: The peak and base load generating stations

Generating Unit	Type of load	0utput Power(MW)	Fuel Cost(N/Hr)	Economic Efficiency (N/MWHr)
1	Base load generating unit	648.7288	5780.859	8.91106
2	Base load generating unit	214.8528	2572.212	12.010122
3	Base load generating unit	410.1224	4072	9.92874
4	Peak load generating unit	115.68	1592.89	13.7698
5	Base load generating unit	205.1377	2567.001	12.51355
6	Peak load generating unit	5.480223	261.4681	47.7112
	Total	**16000**	**16846.43**	**104.844472**

In a deregulated marketplace, the generators with the cheapest Fuel Cost/incremental cost will be chosen to dispatch first. As seen in Table 9.0, Generating Unit No. 6 is the most expensive while Generating Unit No. 1 is the cheapest in terms of fuel cost and N/MWHr. Hence, Generator Unit No. 1 would be dispatched first and Generator Unit No.6 last. With full load being 4000 MW and assuming negligible losses the Generating Units will be dispatched as shown in Table 9.0. This is because generator 1 is not only the cheapest but also one which has the best generating capabilities in the system .It is also realized that cheaper generators will have higher profit margins regardless of the spot prices. Therefore, it is advantageous for companies to own a greater number of cheap generators along with a few expensive ones. Those expensive generators can be used as backup units for emergencies. From these results obtained, it can be concluded that types of generators owned by companies affect their overall revenue. Table 7.0 and fig 9.0 show the impact of unit commitment in any integrated power system. Total Fuel Cost per day with out considering unit commitment =749301.62N/Hr

Total Fuel Cost per day by considering unit commitment = 748813.64N/Hr

Total Saved Fuel Cost = 749301.62N N/Hr -748813.64N/Hr

487.98N/Hr

Total Fuel cost saved per day = 487.98N/Hr

$$\% \text{ saving in Total Cost per hour} = \frac{487.98\text{N/Hr x } 100\%}{748813.64} = 0.065\%$$

Total Fuel Cost /MWHr without unit commitment=183.5473863 N/MWHr

Total Fuel Cost /MWHr with unit commitment = 183.2272733N/MWHr

Total Fuel cost saved per MWHr = N0.320113/MWHr

$$\% \text{ saving in N/MWHr} = \frac{183.5473863 - 183.2272733x100\%}{183.227233}$$

$$= \frac{0.320113x100\%}{183.227233}$$

=0.175%

It can be observed from the results that 0.065% saving in the total cost and 0.175% in N/MWHr can be achieved per day. That means, for one whole day the total costs of more than 500N/Hr or 0.320113N/MWHr has been saved. The proposed techniques and approach give better results in terms of costs optimization. In this case, it can be clearly proved that applying the optimal solution techniques can lead to remarkable cost optimization and increase profits for generation companies.

VII. Conclusions And Recommendations

7.1 Contribution Of The Work

Over the years and under the government-controlled agencies for electricity production the public has never had the privilege of knowing the cost of each unit of electric energy produced by the power generating companies in each country. With the current deregulation of power industries all over the world. This research work found it necessary to analyze the cost of producing electricity in some major stations so that it will be a guide for prospective investors that that want to invest in the industry.

7.2 Conclusions

In this research work, Langrage Relaxation method was applied to solve the economic load dispatch problem with security constraints. The approach was tested on the AEP and CIGRE test systems. The main security constraints considered are the generated active power limits and total power demand.

Considering the cases and comparative study presented in this work, Lagrange Relaxation Economic Load Dispatch algorithm appears to be very efficient in particular for its fast convergence to the global optimum and its interesting financial profit. This method is highly appropriate for on-line applications in power systems. The Lagrange Relaxation (LR) has been applied on power system with 14 generating units. It has been established that the use of LR for obtaining optimal number of generating units under given load conditions, leads to a high profit in the running cost of the order of approximately N85346.8344 per day. It amounts to a net profit of N 31151594.56 per annum. This research work concludes that deregulated electricity markets can be beneficial as long as factors such as long-term generational investments, predictability of fuel prices, and the type of deregulated structure used are considered.

7.3 Observations

1. Case A result shows that power pooling has advantages such as savings in total operating costs which can be split between generating companies.
2. Case B shows that the generator outage of any unit is not only raised the system incremental cost by about 5.3% but also increased the operating costs of all the other generating entities by about 9.4%.
3. In Case C it can be seen that a 50 % rise in fuel costs has brought about a 50 % rise in the system incremental cost; a cost that would have definitely been passed on to the end-use customers. Hence, the results conclude that the relationship between fuel prices and incremental costs is approximately linear.
4. In Case D it was seen that a selective dispatch (based on market rules that cheaper generators are dispatched first and generators not needed are not dispatched) sets the spot price with much more flexibility the end result of which is that consumers pay for electricity according to the demand load. Therefore, this improves residential, industrial and overall economic conditions, leading to a stable market structure. The effect of the type of generator owned by a generating company on profits was also examined in Case D. It was concluded that it is good for a generating company to own cheaper generators with a few expensive ones for backup if needed. Hence, the type of generators and the spot price greatly affect the revenue of a generating company.

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