Investigating the Effects of Increased Thermal Generation by Unit Commitment Optimization in Hydrothermal Power Systems Using Lagrange Algorithm.

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ORIGINAL RESEARCH

Abstract— Optimization assists power utility in operating the system conveniently, meeting customer's load demand, reducing peak load consumption, and minimizing transmission system losses. It involves determining the best operating levels for electric power plants to meet the needs of a given network. This paper aims to present an optimization analysis of the economic distribution of generated electricity among the various generation units to meet load demand at the minimum possible cost using the Economic Load Dispatched. Nigerian existing hydrothermal network (a deregulated system in 2013) along with the newly added unit (Olorunsogo thermal unit) was used as the case study. The obtained data from Nigerian power utility were processed via MATLAB to generate the Quadratic Cost Function (QCF) used to model the generator to get the Cost Coefficients. The Lagrange algorithm developed was also applied to the data using MATLAB to have Dynamic Load Scheduling (DLS) for both hydro and thermal plants. The results indicate cost reduction which enhanced the overall performance and reliability of the system. Observation shows that the newly added thermal unit (Olorunsogo Unit) is efficient and cost-effectively operating. Results also show that hydro plants were allocated high loads, and the system's smooth operation would require bringing the old thermal units such as Afam, Calabar, Egbin, and Sapele plants online to enhance an improvement in generation demand. Other thermal plants like AES, Delta, and Okapi run at lower power implying their uneconomical unit operation implying their uneconomical unit operation.

Keywords— Lagrange Algorithm, Load Scheduling, Operating Cost, Optimization Analysis, Quadratic Cost Functions.

1 INTRODUCTION

Optimization in a power system refers to economic dispatch, and it is the planning or arrangement necessary in generated power utilization or available energy to meet the varying load demand guaranteeing maximum safety of network equipment and personnel. However, it should be at a reduced generation cost and ensure system constraints are not violated while meeting the forecasted load demands (Lewi, *et al.*, 2023). The non-storing nature of electricity necessitates the challenge requirement to meet the varying load demand at any time. Therefore, unit commitment is used in determining when generating units are to be switched ON and OFF which are respectively refers as start-up and shut-down schedules to meet the load demand forecast that varies with time (Salman, et al., 2022). While meeting the load demand, inequality, and equality constraints needed to be satisfied without prejudice to other units' characteristics, such as the unit availability, unit dispatch order, must-run units, etc. The units designated as must-run are usually fully or partially dispatched due to logical reasoning, environmental impact, or operational status to provide generation and transmission support.

For the unit dispatch order, the manner of dispatching the available units is often adopted and depends on the nature of the plant and the operator in charge. Unit availability is particularly important because some units perhaps may be off-line due to any or combination of these outages; forced, planned and grid load – shedding. As a result, dispatch is often done based on unit availability to efficiently satisfy the demand. All that have been discussed above and other elements combine to form problems that determines whether a particular unit in the system deserved to be switched ON or OFF.

Nigerian power supply system is generally epileptic and characterized by poor facilities that in turns makes the power output to be unstable and unreliable. Foreign investors have been fleeing the country searching for the possibility of their engagement in one way or the other. The pathetic situation of Nigeria's electricity companies is presently resulting in job losses and the deterioration of the Nigerian economy. The Nigerian power generating stations are located at different point which are far from each other, some of which are extremely old and others of which are new, implying that they cannot have the same cost functions. In addition, a list of other factors such as outdated infrastructure, radial network instead of a ring main, overloaded transformers, etc. causes system collapse which eventually results in substantial transmission and distribution losses due to poor voltage profile (Salman, et al., 2022).

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Section B- ELECTRICAL/COMPUTER ENGINEERING & COMPUTING SCIENCES
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Considering the issues, it becomes necessary to examine the cost functions of the available integrated thermal generating stations, as well as their power limits and maximum power demand, to efficiently schedule generation. The thermal power plants generally have different fuel cost functions because of their different energy sources which includes, oil, natural gas, coal, or nuclear power. Consequently, providing cheaper power mean that the load must be dispersed across several power stations in such a way that the generation cost is minimized. Thus, only an efficient schedule of power generators that meets electricity demand can guarantee attaining reliable power output (Abdou & Tkiouat, 2018). The efficiency of generating units, transmission losses, and running expenses are all key aspects to consider when considering the system's economic operation. As a result, the primary goal of power system operation is to generate and transfer enough electricity to meet system load demand while minimizing fuel costs and emissions (Dutt & Dhamanda, 2013; Banerjee & Sarkar, 2017; Shuaib, *et al.*, 2017; Kumar, Garg & Lal, 2013). As a result, hydrothermal scheduling is crucial. The goal of optimum hydrothermal scheduling is to reduce the cost of fuel for thermal plants while maintaining water availability for hydro plants over a particular time.

Abanihi and Ndunagu (2019) worked on optimal scheduling of the Nigerian Integrated Power System using the Jaya Optimization Algorithm, which considered the impact of valve point loading (JOA). Economic load dispatch is a non-linear optimization problem which is of great importance in power systems. The paper proposes the optimal scheduling of the Nigeria Integrated Power System considering the valve point loading effect using the Jaya Optimization Algorithm (JOA). The authors obtained the required data from Osogbo, Osun State, Nigeria at the National Control Center (NCC). The cost function of thermal stations known to be active on Nigeria's national grid was developed. MATLAB program was written using the Jaya Optimization Algorithm (JOA), Pattern Search Algorithm (PSA), and Genetic Algorithm (GA) to optimally schedule power on the network considered. The schedule with JOA gave a cost less than PSA. PSA results also gave a cost lesser than GA. The aftermath of the simulation shows the merit of the selected technique in reducing the overall cost of power generation over the other techniques.

Bello, *et al.*, (2016) focused on unit commitment optimization of hydro-thermal power systems in the day-ahead electricity market. Unit commitment (UC) problem is being faced in power system control, coordination and operation. The authors worked on new formulation and classical exhaustive enumeration search method for UC problems for scheduling hydrothermal units in the day-ahead electricity market. During the research, minimization of production cost and maximization of the energy consumption are the key objective functions considered. Proper handling of Constraints was achieved by letting both the thermal constraints (up/down-time of thermal units) and hydro power constraints (the turbine operation of hydro power stations) be embedded in the binary strings which are coded to represent the on/off-states of the generating units. To demonstrate the effectiveness of the proposed technique, Nigerian 330 kV transmission grid having four thermal and three hydro-power units was used. The studies under different scenarios for a 24 hours horizon gave the desired results. The technique is less in computationally efficiency compared to other methods but has a high accuracy of optimal solution. These results are comparable with the ones in literature which affirm the effectiveness of the technique. Thus, the approach generated better solutions in many cases especially when dealing with power systems that have less than 20 units.

Amosi, Musa & Thuku (2017) discussed how Particle Swarm Optimization (PSO) Algorithm could be used to optimize an Economic Load Dispatch (ELD) problem with the Nigerian's hydrothermal power network a case study. The study is aimed at optimal allocation of the demand among the available units to minimize the total generation cost despite the involved constraints The results obtained from the Thirty-one busbars network when compared with other techniques shows that PSO optimization technique gave the least production cost and transmission losses better than Genetic Algorithm (GA) and Differential Evolution (DE).

Ade-Ikuesan *et al*. (2019) emphasized the need optimally schedule the output of thermal units on power system. The authors discussed the population-based artificial intelligence (AI) algorithms as another option to address the ELD problems. This AI method is adopted because of reasonable processing speed, less computational complexity and short computational time. The authors aimed at presenting all AI algorithms that had been used and along with the types of ELD problems solved. From the review carried out, it was realized that varieties algorithms had been applied to solve ELD problems. Furthermore, the review revealed that cases of gas emission, option of multiple fuel, requirement of spinning reserve and ramp rate limit are areas that have not been researched talking about Nigerian hydrothermal units. Also, reactive power dispatch on Nigerian grid has not been well researched as well. Kumar & Mohan (2003) also embarked on review of hydrothermal papers. It was noted that the fuels are not quite available in excess and produce emissions which considered as hazard to populace the environment. Therefore, it becomes inevitable to minimize its usage. Hence, the analysis that carries out minimization of fossil fuel consumption by generating plants is refers to as generation dispatch. The authors looked at the Generation dispatch problem of the

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Nigerian transmission grid, the first of its kind since the system deregulation about ten years ago. The author's review covered the types of GDP, associated constraints, and the optimization technique used for the GDP solution of the Nigerian power network. The obtained results revealed that nothing much has been done.

Tijani, Adepoju & Okelola (2022) ELD minimizes the overall cost of fuel required to serve the system load which is the key responsibility that often determines the output of thermal units on the system. The author aimed to develop a dynamic load scheduling to reduce cost and improve performance and network reliability. The optimization involved formulating the ELD problem using MATLAB software packages. The results indicate that it is economical to generate energy in grid expansion of hydrothermal units and also observed that the grid units which are mainly thermal units eased the load stress on the old units, thus reducing the effect of power transmission losses and consequently moderating the total cost of generation.

Pereira, Ferreira & Vaz (2012) looked at how to self-schedule an energy system mostly made up of wind power fossil fuel, hydro, and thermal facilities. The authors define a binary mixed-integer non-linear optimization model, and its application was made for a short-term electricity planning system. This system is like the one that is projected in Portugal in 2020. The model was developed in GAMS, and the numerical results are obtained using a global optimization solver. Buraimoh, Ejidokun & Ayamolowo (2017) focus on optimizations of the Expanded Nigeria Electricity Grid System using Economic Load Dispatch. The method of economic Load Dispatch was used. This method determines the output power of each thermal power plant, which minimizes the overall cost of fuel needed to serve the entire system load.

Consequently, this paper presents an optimization analysis of the economic distribution of generated electricity (loads) among the various generating units to meet load demand at the minimum possible cost, considering the existing and the newly added thermal power plant. Section 2 presents the unit commitment problem formulation, the methodology, a description of the case study network, the accumulation of data collected, determination of Olorunsogo power station's quadratic cost function which modeled generators and thus simplifies the mathematical formulation in obtaining the cost coefficients for the thermal units. An application of the developed Lagrange algorithm to the cost function of the remaining Nigerian thermal generating stations other than that of the Olorunsogo power plant is obtained from the literature (Bello, *et al.*, 2016). Section 3 presents the results and brief description of the results while Section 4 concludes the study.

2 The Materials and Method

Generating stations are located far away from the center of the loads. Some of the equipment in the station are old and while others are new, thus, theses equipment cannot have equal cost function. In addition, aging infrastructures, and overloading of transformers often because frequent system collapse with large distribution losses (Bello, *et al.*, 2016).The demand for electricity is rapidly rising, while power plant operation is growing more expensive due to expensive and scarce resources. Therefore, as electricity is more demanded during the daytime and at the peak periods but low demand at off peak periods. This call for power utility companies to plan for generation output considering all possible constraints. Consequently, achieving the demand at minimum operation cost, the generating stations must decide the unit to start up, time to tie, time to shut down and outage hours of that unit (Adesina, 2022; Oluseyi, *et al.*, 2019; Hansen, 2015; Liaquat, Zia & Benbouzid, 2021; Kandasamy & Selvara, 2017). This procedure is referred to as unit commitment and is mathematically presented in this paper. Some of the symbols used and their interpretations are presented in Table 1.

Table 1: Description of the symbol used

Symbol	Description
$P_{i\,min}$	Minimum generating limit
$P_{i\,max}$	Maximum generating limit
F_c	Total cost for supplying the indicated load
αi, βi and γi	Cost coefficients
L	Lagrange function
N	Number of available units
PD	Power demand
Pi	Generated power by the ith
λ	Lambda

2.1 Model Formulation

The constraints and limitations such as demand requirements, system capacity, and government policies add to unit commitment problems. The constraints are expressed as mathematical equations, specifying the possible values of the decision variables.

Equality Constraints: The constraint derives from the system's requirement to balance load demand and

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generation as presented in equations (1) and (2) (Adesina, 2022; Maifeld & Sheble, 1996).

$$P_i - P_{load} - P_l = M_i = 0 \quad (1)$$

$$Q_i - Q_{load} - Q_l = N_i = 0 \quad (2)$$

Where;

$\boldsymbol{P_i}$ = Scheduled active power generation

$\boldsymbol{Q_i}$ = Scheduled reactive power generation

$\boldsymbol{P_{load}}$ = Active load demand

$\boldsymbol{Q_{load}}$ = Reactive load demands.

$\boldsymbol{M_i}$ = Residual active power at bus

$\boldsymbol{N_i}$ = Residual reactive active power at bus *i*

$\boldsymbol{P_l}$ and Q_l are power flow in the neighboring system.

Inequality Constraints: Some restrictions become necessary due to operational and physical limitations of the units and components. Effective operation of the generator requires that power inequality limits be applied. Thus, a minimum and maximum output allowed for each generator, and unit production needs to be controlled so that the relations in equations (3) and (4) hold (Adesina, 2022; Kumar & Mohan, 2003):

$$P_{i\,min} \leq P_i \leq P_{i\,max}; i = 1,2, \dots N_p \quad (3)$$

$$Q_{i\,min} \leq Q_i \leq Q_{i\,max}; i = 1,2, \dots N_Q \quad (4)$$

N_P and N_Q represent the number of real and reactive power in the system

1) *Demand Constraint: For reliability purposes, a power system must be such that the generated output power should always be sufficient to take care of the demand in each hour of the planning period. Thus, in practice, it is always ensured that the demand power equals the generator power output plus special regime power output, minus pumping consumption. The constraints is mathematically presented as follows: (Oluseyi, et al., 2019; Hansen, 2015).*

$$\sum_{j\in J} \boldsymbol{Pt_{t,j}} + \boldsymbol{Phd_{t,h_d}} + \boldsymbol{Phr_{t,h_r}} + \boldsymbol{Pwind_{t,e}} - \boldsymbol{Ppump_{p,j}} + \boldsymbol{Psr_{p,t}} = \boldsymbol{D_t} \forall \boldsymbol{t} \in \boldsymbol{T} \quad (5)$$

Where,

$\sum_{j\in J}$ = the summation over all *j* elements in set *J*, likely representing different generators or sources of power.

$\mathbf{Pt_{t,j}}$ = the power output from generator *j* at time *t*.

$\mathbf{Phd_{t,h_d}}$ = the power from hydro sources at time *t* and hour $\mathbf{h_d}$.

$\mathbf{Phr_{t,h_r}}$ = the power from other renewable sources at time *t* and hour $\mathbf{h_r}$.

$\mathbf{Pwind_{t,e}}$ = the power from wind sources at time *t* and hour *e*.

$\mathbf{Ppump_{p,j}}$ = the pumping consumption for pump *p* and generator *j*.

$\mathbf{Psr_{p,t}}$ = special regime power at pump *p* and time *t*.

$\mathbf{D_t}$ = the demand power at time *t*.

The equation states that the sum of power outputs from generators, hydro, other renewable sources, wind, minus the pumping consumption, plus any special regime power, should equal the demand power for each time period *t* in the set *T*.

This equation essentially ensures that the total generated power, considering various sources and factors like pumping and special regimes, is sufficient to meet the demand at each time period.

2.2 Incremental Fuel Cost

This is a measure of the cost of producing an increment of power. The incremental fuel curve (F_c) can be obtained from the incremental fuel rate curve (IFR) by multiplying the IFR by the cost of fuel [4]. Thus, incremental fuel cost is also obtainable using equation (6) (Bello, *et al.*, 2016; Oluseyi, *et al.*, 2019; Montero, Bello & Reneses, 2022):

$$F_c = \alpha_i P_i + \beta_i P_i + \gamma_I \; unit\ of\ cost/hr \quad (6)$$

Where,

F_c = the cost rate of the unit.

P_i = the output of each unit, which represents the electrical power output of units.

α_i,β_i and γ_I = the coefficients of the quadratic cost function of the unit's power.

To achieve the minimum value of the objective function (F), use of the langrage function (L) is conventional. The cost function F is added to the constraint function after an undetermined multiplier (λ) multiplies the constraint. The Lagrange function is given as:

$$L = F + \lambda\,[P_{load}] - \sum_{i=1}^{N} P_i \quad (7)$$

$$\frac{\partial L}{\partial Pi} = \frac{dF_i(P_i)}{dP_I} - \lambda = 0 \quad (8)$$

$$\lambda = \frac{dF_i(P_i)}{dP_I} \quad (9)$$

When the incremental cost Rate $\frac{dF_i(P_i)}{dP_I}$ of the entire unit is equal to λ, the Lagrange multiplier.

For N number of such units, economic operation is thus attained when

$$\frac{dF_1(P_1)}{dP_1} = \frac{dF_2(P_2)}{dP_2} = \cdots \frac{dF_i(P_i)}{dP_I} = \cdots \frac{dFN(PN)}{dPN} = \lambda \quad (10)$$

2.3 Minimization of Total Production Cost

When a plant is shut down, the group of customers enjoying electricity supply via the plant must be on outage for a specified amount of time referred to as minimum downtime. In the same way, when a generator starts up; the group of customers must enjoy the electricity supply for a specified amount of time referred to as minimum uptime. However, costs incurred in power generation by both thermal and hydro units are to be minimized at an optimal output of total system units in line with the objective function. Thus, the objective function is mathematically described as (Lewi, *et al.*, 2023; Bello, *et al.*, 2016; Muralikrishnan, Jebaraj & Rajan, 2020).

$$A = \phi + \theta \quad (11)$$

Where:

θ = Thermal running cost

ϕ = Hydro Running Cost.

Thermal **Running Cost:** The majorly embedded costs in thermal running cost are unit start-up (S), unit short - down (D), crew (C) and fuel (F). Therefore, the thermal unit running cost is related to its associated parameters by the expression (Bello, *et al.*, 2016).

$$\theta = F + S + D + C \quad (12)$$

Where;

F = the fuel cost and can be obtained by second-order quadratic cost function (QCF) which also contains the heat rate of unit and fuel price. This second-order quadratic cost function (QCF) is shown in equation (13):

$$F_j^t = \sum_{t=1}^{24} \sum_{j-1}^{Q} \left[\left(\alpha_j + B_j P_j^t + \gamma_j \left(P_j^t\right)^2 \right) P_j^t \right] \quad (13)$$

S = the startup cost is cost of switching-ON the thermal units. There are two types, banked startup cost (B) or cold start-up cost (K). Cold start-up cost is the expenses of re-committing a unit which was off - line for a reasonable length of time (i.e., longer than its minimum downtime). The mathematical formulation is shown in equation (14) (Bello, *et al.*, 2016)

$$k = \left(1 - e^{-t_j/\tau_j}\right) F_j^t + C \quad (14)$$

From equation (14) above, as the unit cooling time increases, the exponential component of the equation tends to zero.

Banked start-up cost is the expense of re-committing a unit that has met the minimum downtime (i.e., the unit has just been shut down not quite long before the time of recommitment). Thus, banked start-up units have their operational temperature as shown in equation (15).

$$B = O_j^t + C \quad (15)$$

2.4 Description of Nigerian 300kV Transission Grid

Figure 1 shows the one-line diagram of the Nigerian 330 kV transmission grid, which is the case study. Table 2 displays the busbars identification numbers of the grid network in Figure 1. These bus numbers are unique to the buses and will be used to identify the buses within the MATLAB programs and the other input data

Table 2: Busbars identification on Nigerian 330 kV Transmission Grid (Abanihi & Ndunagu, 2019).

Bus Number	Bus Name	Bus Number	Bus Name
1	Egbin	15	Ayede
2	Delta	16	Osogbo
3	Kanji	17	Benin
4	Shiroro	18	Ajaokuta
5	Sapele	19	Akangba
6	Jebba G.S	20	Ikeja
7	Afam	21	Onitsha
8	AES	22	New Heaven
9	Okpai	23	Alaoji
10	Calabar	24	Aladja
11	Gombe	25	Aja
12	Jebba T.S	26	Birnin
13	Jos	27	Kaduna
14	Katampe	28	Kano

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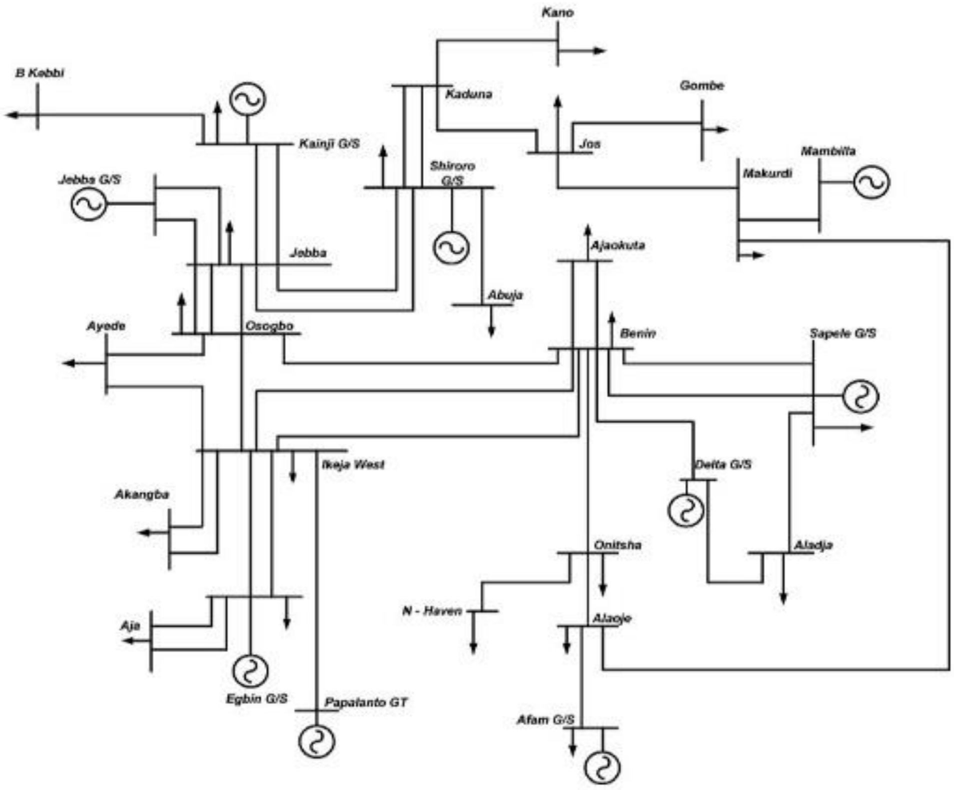

Figure 1: Nigerian 330 kV, 28-Bus Power Network

2.5 Power Generation Plant Data

The plant data in this case are γ, β, α, P_{max}, and P_{min} power output. All these data are obtainable from the generating station's logs or the manufacturer's data sheet as shown in Table 3. Considering the fuel cost factor, β in the cost equation of the hydro plants is approximately zero since the fuel cost of hydro stations is also negligible.

2.6 Data Collection, Accumulation and Quadratic Cost Fuction Determination

The power generated daily by the Olorunsogo thermal power unit for one year was collected from the power utility company. These data were organized and analyzed using Microsoft Excel for quality presentation. Microsoft Excel was therefore used as a database because it is easy to maintain and retrieve words. MATLAB software was used to analyze the data and plot the various graphs shown in Figures 4 to 11 for visual analysis. Furthermore, MATLAB as a high-performance language for technical computing was also used to process the data to obtain the Quadratic cost functions which were eventually used to model the generators to simplify the mathematical formulation to get the cost coefficients for the thermal units. The obtained quadratic cost function of the Olorunsogo power plant (newly added unit) from the data of load and volume of gas used by each generator is presented as a result in Figure 3.

2.7 The Proposed Lagrange Algorithm Method

The gradient technique is a Lagrange iterative strategy to solve the optimal scheduling issue with first derivatives to minimize the cost function of a generating station. It was assumed that the system has N units connected and that penalty factors are utilized to account for the losses (Kumar, Garg, and Lal, 2013; Abanihi & Ndunagu, 2019). It reduces the incremental fuel cost function associated with each thermal power generator. MATLAB, a software with integral computation, visualization, and ease of programming is often used in handling technical computing. Data are processed via this MATLAB software to obtain the Quadratic cost functions that modeled generators and thus simplify the mathematical formulation in obtaining the cost coefficients for the thermal units.

2.8 Implementation and Simulation

The developed Lagrange algorithm was applied to the obtained cost function of the Olorunsogo thermal station and the cost function of the Nigerian hydrothermal generating stations obtained from the literature (Okozi, et al.*, 2019) considering that the transmission losses is at minima using MATLAB. The developed flowchart used in this implementation is shown in Figure 2a and 2b. While the results obtained for the cost functions of the hydrothermal stations as well as their corresponding maximum and minimum power limits were used*

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in calculating the total fuel cost. The results is graphically shown in Figure 10.

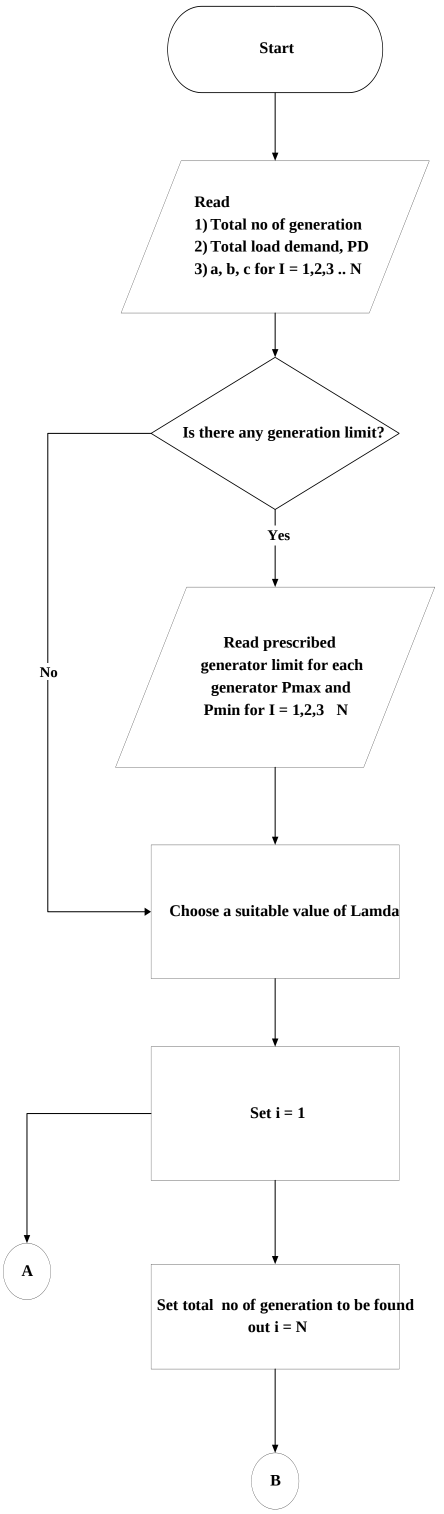

Fig. 2(a): Flowchart of Lambda Iteration Technique for Economic Load Dispatch

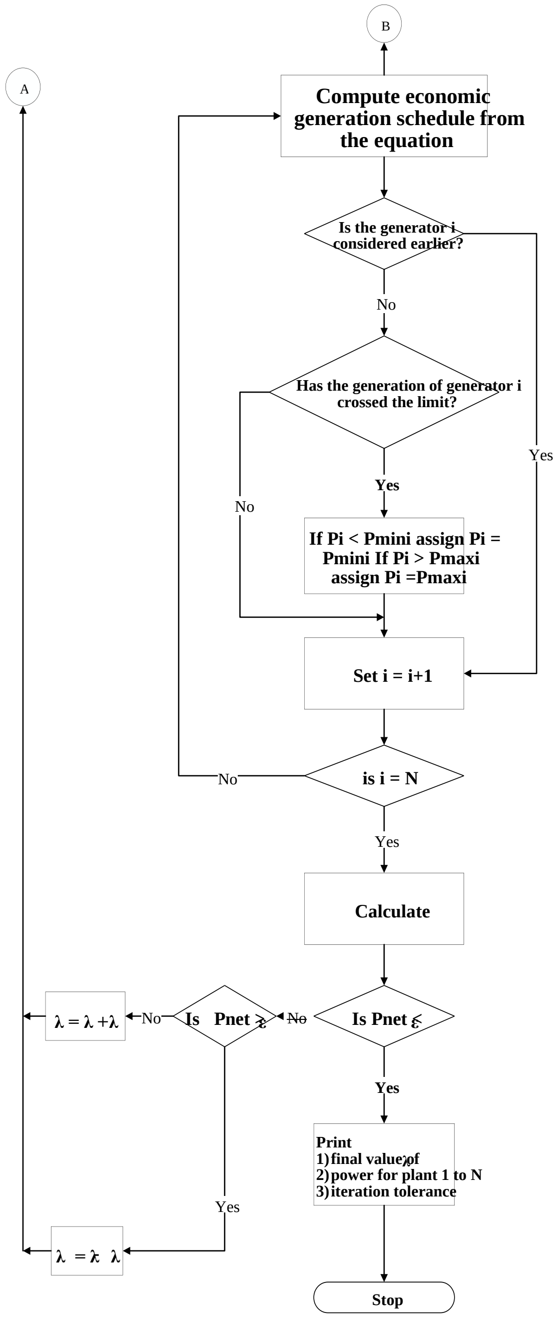

Fig. 2(b): Continuation of Flowchart of Lambda Iteration Technique for Economic Load Dispatch

3 Results And Discussion

A comparison of shared loads (MW) among thermal plants is discussed in this section. Except for DELTA, OKAPI, and AES which run at minimum power limits, the total output from the units grows as the load demand increases as illustrated in Figure 4.

In Figure 5 (Egbin thermal station), when the load demand rises from 2000MW to 2750MW, the thermal plants that are considered old and have long years of operation move progressively into maximum operation. It could also be observed that the Egbin power plant maintains its operation at a maximum limit beyond the time when power demand rose to 2750MW. However, AFAM in Figure 6 is operating at its maximum limit. When the total demand was increased further, Sapele and Calabar joined in the operation near the limit. The implication is that it boosts overall demand, and these thermal plants can be put into full system operation sequentially as follows; Egbin, Afam, Sapele, and Calabar. Based on the results obtained, the analysis shows the cost-effectiveness and economic implications of bringing into full operation a new thermal plant called Olorunsogo which satisfies the rising load demand. Furthermore, Figure 10 illustrates the increase in total generation cost as overall generation output rises. Thus, as the total power demand approaches 2750MW, the generation cost rises exponentially as most thermal plants operate at or near their maximum capacity.

Looking at the comparison of shared loads (MW) among thermal and hydro plants, the output of the MATLAB program illustrated in Figure 11 is the optimal schedule for the eleven (11) plants considered in this study. Therefore, it is observed that a high load is allotted to the hydro generating stations such as Kanji, Shiroro, and Jebba hydropower stations in addition to the thermal plant (Egbin) while Olorunsogo operates at the maximum power limit this is due to the high efficiency and low generation cost of these plants. It is also observed that (Delta, Afam, AES, and Okapi thermal power stations) operate at minimum power limits implying that they are the most uneconomical units.

It is important to note that some data were not available for collection and subsequent use. Thus, it becomes difficult for the authors to determine the transmission losses. Therefore, transmission losses should be estimated to measure plant performance to compare the analysis results with the previous work done properly

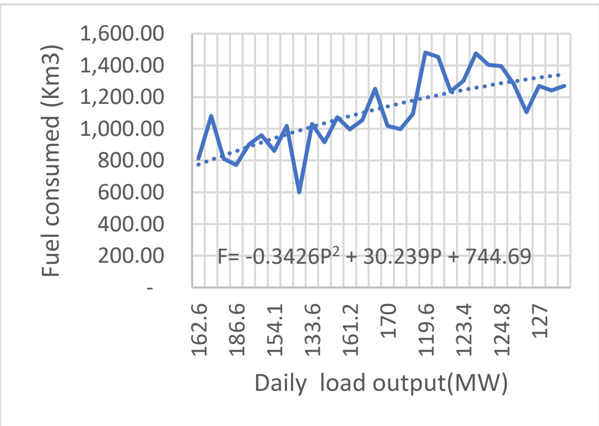

Figure 3: Quadratic Cost Function of Olorunsogo Power Plant

Table 3: Characteristics of the Nigeria Hydro and Thermal Plant

S/N	Plant	α	β	γ	P_{min}(MW)	P_{max}(MW)
1	Olorunsogo	744.69	30.23	0.3426	60	336
2	Delta	525.74	6.13	1.2	75	300
3	Afam	1998	56	0.0092	135p	540
4	Sapele	6929	7.84	0.13	137.5	550
5	Egbin	12787	13.1	0.031	275	1100
6	AES	3886	22	0.453	135	540
7	Okpai	480.58	10.3	1.13	150	600
8	Calabar	2732	38.7	0.05	100	350
9	Kanji	15200	0	0.05	50	500
10	Shiroro	8200	0	0.027	50	450
11	Jebba	2552	0	0.07	100	400

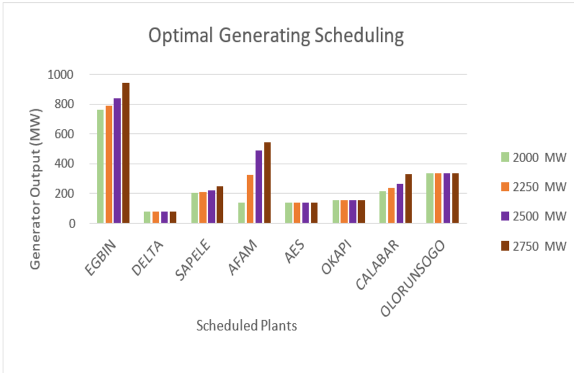

Figure 4: Thermal Plants Handling Power Demands between

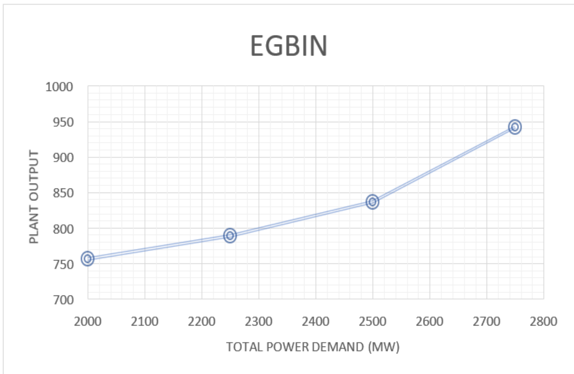

Figure 5: Egbin Generation Output

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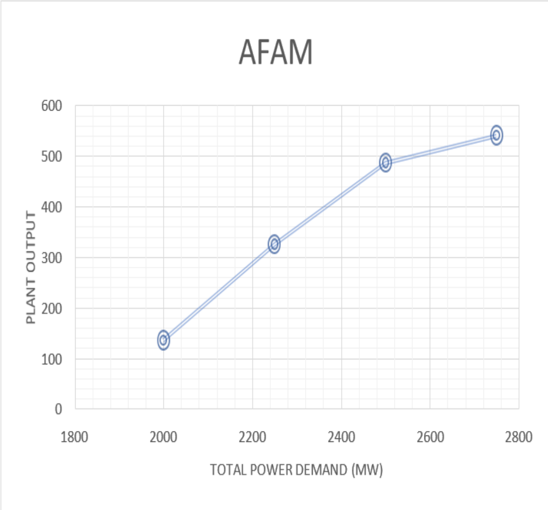

Figure 6: Afam Generation Output

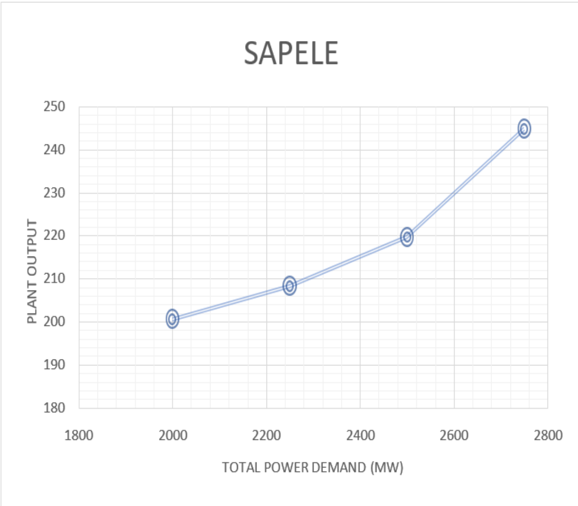

Figure 7: Sapele Generation Output

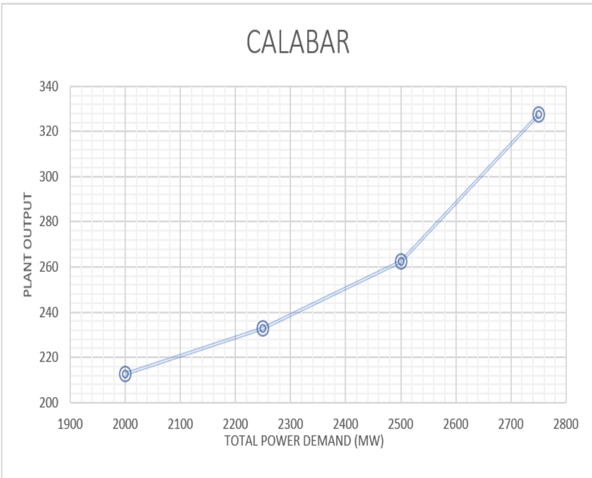

Figure 8: Calabar Generation Output

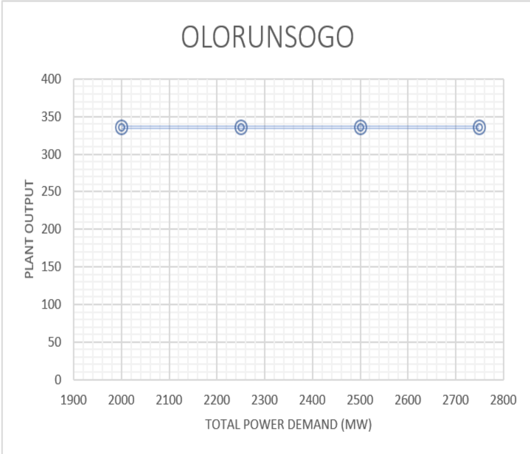

Figure 9: Olorunsogo Generation Output

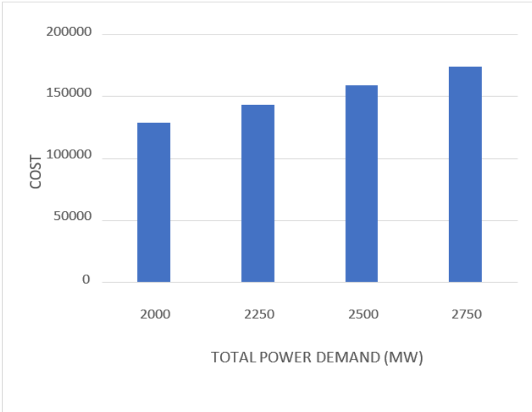

Figure 10: Generation Fuel Cost (cost/h) against the Power Demand (MW)

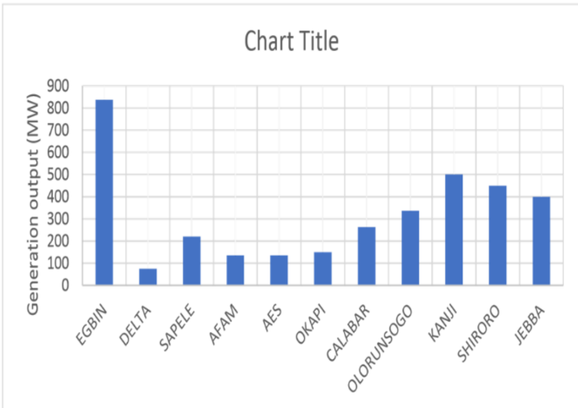

Figure 11: Graphical representation of the optimal distribution of 500MW among the online generators.

4 Conclusion

Optimal scheduling determines the generation output of various plants while keeping running costs to a minimum. As a result, operating costs play a significant part in economic planning. This is demonstrated in the Lagrange algorithm for economic scheduling in multisource power generation such as hydro and thermal units. From the optimal schedule for the eleven (11) plants which is illustrated in Figure 11, a high load is allotted to the hydro generating stations (Kanji hydro station, Shiroro hydro station, and Jebba hydro station) in addition to the thermal plant (Egbin), while Olorunsogo operates at maximum power. This is due to the high efficiency and low generation cost of these plants. It can also be noted that (Delta, Afam, AES, and Okapi thermal power stations) run at the lowest possible power, implying that they are uneconomical units. Bringing of these thermal plants online in the order Egbin, Afam, Sapele and Calabar will improve the overall efficiency and thus increase demand because the suppressed loads might come up. According to the results of the optimization, it is more cost-effective to bring a new thermal plant (Olorunsogo) online to meet the increased load demand. However, it is important to note that some data were not available for collection and subsequent use. Thus, it becomes difficult for the authors to determine the transmission losses. Therefore, transmission losses should be estimated to measure plant performance to compare the analysis results with the previous work done properly.

DECLARATIONS:

Competing Interest: The authors declare that he has no competing interests that is associated with this paper.

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AVAILABILITY OF DATA AND MATERIALS:

Daily energy generation data were collected from Olorunsogo Power Generation Company, a subsidiary of Nigerian Power Utility. Other used data were obtained from referenced 9

AUTHORS' CONTRIBUTIONS:

The research work was carried out by the stated author only. The search for data, collation of the data and its results as well as the development of the manuscript for publication in an academic journal were all handled by this author.

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