International Refereed Journal of Engineering and Science (IRJES)
ISSN (Online) 2319-183X, (Print) 2319-1821
Volume 15, Issue 2 (Mar. – Apr. 2026), PP. 54-60

Power Plant Generation Scheduling for The Coordination of Reliable Power Supply from First Independent Power Limited (FIPL)

Enyi I. Perfect[1*], Dr. DanHorsfall[2]
Electrical and Electronics Engineering Department, Rivers State University,Nigeria

Abstract
The problem of power plant generation scheduling for the coordination of reliable power supply from First Independent Power Limited (FIPL) has been a major concern. The tendency to match intended daily load demand to the available plant capacity through synchronization has resulted in the loss of revenue, blackout or outages thereby reducing the production rate. This research considered the application of Lagrangian Relaxation Technique most specifically the cost equation together with the unit commitment data for the 4 generating units of the power plant with the view of reducing the cost of operation and improving the scheduling and coordination of the generating unit over 24hours in 7 periods (A-G).In the month of September, 2023 the total cost of operating the 4 generators based on unit availability amounted to ₦399,874,740, while the total cost of operation based on the cost function of the 4 generators in the month of May, 2024 amounted to ₦332,120,240. The results obtained from the unit commitment data of the 2years were compared with respect to the approach used in the research and the comparison shows that the scheduling of generation based on their cost function led to the reduction in the cost of operation by ₦67,754,500, which is 17% for the 24hours period. This means that the proposed technique will enhance the effective scheduling and coordination of reliable power supply from FIPLs power plant.

Keywords- *Cost Function, Generation Scheduling, Economic Dispatch, Unit Commitment, Lagrangian Relaxation Technique.*

Date of Submission: 08-04-2026 Date of acceptance: 20-04-2026

I. INTRODUCTION

An electrical power system usually consists of thousands of transmission lines and hundreds of generating units. The operation of such a large-scale system should account for the continuous variation of consumer demands. In order to ensure the reliability of the economic operation of this type of systems, power system scheduling is based on two important decision-making processes. First, commitment states (on or off) of generating units in the system should be determined in every time interval of the scheduling time horizon, (Wood & Wollenberg, 2021). This problem is referred to as the "unit commitment problem". Another decision, which is called "economic dispatch", will allocate the power demand to the committed units. Such an allocation is determined according to the characteristics of the constituent unit. The two decisions depend on each other and their outcomes must be considered simultaneously for a least cost solution. In the scheduling problem, the time horizon usually ranges from one day to one week, and the scheduled power generation should be able to supply the forecasted demand. Efficient scheduling of power generation in thermal power plants is crucial for maintaining a reliable power supply to meet the growing demand for electricity. Thermal units, which rely on the combustion of fossil fuel such as coal, natural gas or oil, constitute a significant portion of the global power generation capacity. Optimizing the scheduling of these units involves balancing various factors such as fuel cost, operational constraints, environmental regulations and demand fluctuations.

The integration of thermal unit into the generation scheduling process requires addressing several key challenges like the variability in fuel prices and availability, necessitate dynamic scheduling strategies to minimize operating costs while meeting demand, also the aging infrastructure of thermal power plants often results in increased maintenance requirements and downtime, which must be properly coordinated with power generations schedules to minimize disruptions and ensure reliability.

II. PROBLEM FORMULATION

- **Objective Function**
  The main objective is to determine the optimal unit commitment schedule for each hour for 24 hours and determine which combination has the lowest fuel cost.
- **Fuel Cost Function**
  According to Putz et al, (2021), & Singhal et al, (2015). The fuel cost function is given as;
  $FC_i = a_i + b_iP_i + c_i{P_i}^2$(1)
- **Start-up Cost**
  The start-up cost is the cost incurred when a generating unit comes up. It depends on the time the generating unit has been OFF before start-up; it can be represented by an exponential cost curve. Brandenberg et al, (2015). The start-up cost equation is given as
  $SC_i = \sigma_i + \delta_i\left(1 - e^{-Toff_i/\tau_i}\right)$ (2)
  Alternatively, the start-up cost can be found using:
  $SC_{i,t} = \begin{pmatrix} Hs_{i,t} \; if \; T_{Down_i} \leq T_{off_i} \leq T_{Down_i} + T_{Cold_i} \\ C_{S_i}, \; if \; T_{off_i} > T_{Down_i} + T_{Cold_i} \end{pmatrix}$ (3)
- **Shut-down Cost**
  This is given as a constant value for each unit. Thus, total cost of production, TCi is given as; $TC_i = \sum_{t=1}^{T}\sum_{i=1}^{N}\left[FC_{i,t} + SC_{i,t} + SD_{i,t} + PF_j\right]$ (4)
  System Constraints
- **Load or power demand (PD) Constraints:** This is the generated power from all units that must meet the system load demand.
  $\sum_{t=1}^{T}\sum_{i=1}^{N} U_{i,t}P_{i,t} = PD_t$ (5)
- **Spinning Reserve (SR) Constraints:** This is the total amount of generation capacity available from all unit synchronized (spinning) on the system minus the present load demand. There are various methods of determining the spinning reserve, spinning reserve with slight changes in load demand which might occur in-between hours are taken of.
  $\sum_{t=1}^{T}\sum_{i=1}^{N} U_{i,t}P_{i,t} \geq PD_t + SR_tm$ (6)
- **Generation Limits:** This represents the minimum loading below which it is not economical to load the unit, and the maximum loading limit above which the unit should not be loaded.
  $U_{i,t}P_{mini} \leq P_{i,t} \leq U_{i,t}P_{maxi}$ (7)
- **Minimum up / Down time:** If the unit is running, it cannot be turned OFF before a certain time elapses and if it is down, it cannot be loaded before a certain time elapses.

$T_{\boldsymbol{off_i}} \geq T_{Down_i}$, $1 \leq i \leq N$ (8)

$T_{ON_i} \geq T_{up_i}$

$$U_{i,t=} \begin{cases} 0 - 1, if \; T_{offi} \geq T_{Downi} \\ 0 - 1, if \; T_{ONi} \geq T_{Up_i} \\ 0 \; or \; 1, otherwise \end{cases} \quad (9)$$

Where;
CS_i Is the cold start-up cost of i^{th} unit at hour t in Naira per hourδ_i.
HS_i Is the hot start-up cost of the i^{th}unit at hour t in Naira per hour σ_i.
J is the index for dimension.
T is the number of scheduling time intervals in hours.
τ_i Is the cooling time constant.

III. MATERIALS AND METHOD

Materials Used

- Generation capacity rating of FIPLs plant
- Generation duration data
- Load demand

Table1: Generation plant and their power ratings

Gen No	Rated power in (KVA)	Rated power (KW)	Rated current (A)	Rated frequency (Hz)	RPM	Rated voltage (V)
Gen 1	24138	19358	1267	50	1500	11000
Gen 2	24138	19358	1267	50	1500	11000
Gen 3	24138	19358	1267	50	1500	11000
Gen 4	24138	19358	1267	50	1500	11000

Method Used for Generation Scheduling

The unit commitment table of the power plant under investigation was used in the work to apply optimum generation scheduling, and lagrangians relaxation cost function was employed. The system under study, distributed loads of plant commitment were appropriately shared among the committed generators with the aim of maximizing energy and cost saving as well as preventing system overload which could cause outage.

The equality constraint is given as;

$P_G = P_D + P_L$ (10)

n = number of generation or plant

P_D = total power demanded

P_L = total transmission loss power

C_T = total cost of generation, $C_{T=C_1+C_2+\cdots+C_n}$

P_{Gi} = generation of the ith plant

Consider the input-output curve of the unit

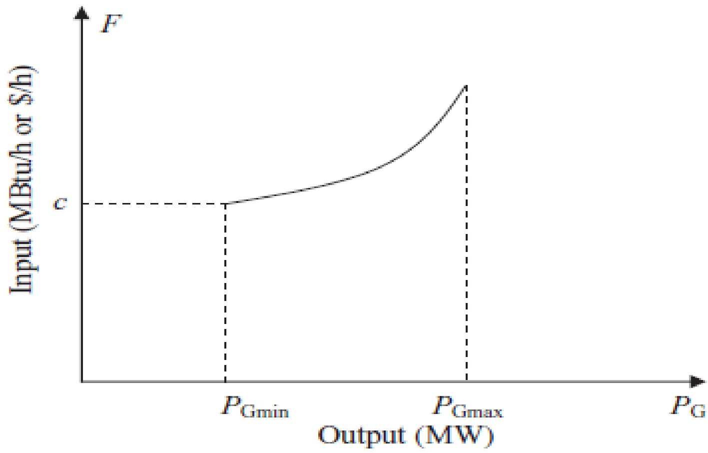

Figure 1: Input-output curve of a generating unit

$$P_{G_{min}} \le P_{G_i} \le P_{G_{max}}$$

$Min\ \sum_i C_i(P_{G_i})$ (11)

Equation of the curve is given as;

$C_i = \frac{1}{2} a_i P^2{}_{G_i} + b_i P_{G_i} + c_i$(12)

Where; a, b, and c are constant of input-output curve and,

C_i Is the cost of power generation atith unit.

Equation for incremental fuel cost is given as;

$\frac{dC_i}{dP_{G_i}} = IFC = IC = a_i P_{G_i} + b_i$ (₦/MW/HR) (13)

$C_T = \sum_{i=1}^{n} C_i$ (14)

For scheduling with generator limit

To minimize cost;

$\sum_{i=1}^{n} P_{Gi} = P_D + P_L$ (equality constraint) (15)

$\sum_{i=1}^{n} P_{Gi} - P_D - P_L = 0$ (16)

$\mathcal{L} = C_T + \lambda f$ (17)

$\mathcal{L} = C_T + \lambda[\sum_{i=1}^{n} P_{Gi} - P_D - P_L]$(18)

To minimize the total cost of generation, $C_T = \frac{\partial c}{\partial P_{Gi}} = 0$ (19)

$\frac{\partial \mathcal{L}}{\partial P_{Gi}} = \frac{\partial C_T}{\partial P_{Gi}} + \frac{\partial}{\partial P_{Gi}}\left[\lambda[\sum_{i=1}^{n} P_{Gi} - P_D - P_L]\right] = 0$ (20)

$\frac{\partial C_i}{\partial P_{Gi}} + \lambda\left[0 + \frac{\partial P_L}{\partial P_{Gi}} - 1\right] = 0$ (21)

The Exact Coordination Equation is given as;

$\frac{\partial C_i}{\partial P_{Gi}} = \lambda\left[1 - \frac{\partial P_L}{\partial P_{Gi}}\right]$ (22)

$\lambda = \frac{\frac{\partial C_i}{\partial P_{Gi}}}{1 - \frac{\partial P_L}{\partial P_{Gi}}} \quad i = 1,2,..,n$ (23)

Penalty factor L_i'

$L_i = \frac{1}{\left[1 - \frac{\partial P_L}{\partial P_{Gi}}\right]}$ (24)

Table 2: Cost function of 4 generation plants.

Generator units	a (₦/MW^2)	b (₦/MW)
Gen 1	35,000	105,000
Gen 2	26,000	78,000
Gen 3	30,000	90,000
Gen 4	32,000	96,000

The cost function for each generator set can be determined for the optimal generation scheduling by integrating the lagrangian relaxation cost equation from equation (12).

$$C_i = \frac{1}{2} a_i {P^2}_{G_i} + b_i P_{G_i}$$

Where a and b are unit constraints.

For Gen 1

$$F_1 C_i(MW) = \frac{1}{2} a_i {P^2}_{G_i} + b_i P_{G_i}$$

$=(0.5)(35{,}000)(19.4)^2 + (105{,}000)(19.4)$

$$= ₦8{,}623{,}300/hr$$

For Gen 2

$$F_2 C_i(MW) = \frac{1}{2} a_i {P^2}_{G_i} + b_i P_{G_i}$$

$=(0.5)(26{,}000)(19.4)^2 + (78{,}000)(19.4)$

$$= ₦6{,}405{,}880/hr$$

For Gen 3

$$F_3 C_i(MW) = \frac{1}{2} a_i {P^2}_{G_i} + b_i P_{G_i}$$

$=(0.5)(30{,}000)(19.4)^2 + (90{,}000)(19.4)$

$$= ₦7{,}391{,}400/hr$$

For Gen 4

$$F_4 C_i(MW) = \frac{1}{2} a_i {P^2}_{G_i} + b_i P_{G_i}$$

$=(0.5)(32{,}000)(19.4)^2 + (96{,}000)(19.4)$

$$= ₦7{,}884{,}160/hr$$

Table 3: Unit commitment table of a day peak production in September, 2023 showing number of committed generation and production.

Period	Duration	Total time	Gen 1	Gen 2	Gen 3	Gen 4
A	12am-7am	7	0	0	1	1
B	7am-9am	2	0	1	1	1
C	9am-12pm	3	1	0	0	1
D	12pm-1pm	1	1	0	0	1
E	1pm-4pm	3	1	1	0	1
F	4pm-6pm	2	1	0	1	0
G	6pm-12am	6	0	1	1	0

Table 4: The periodic power produced by individual generator in a daily peak load in September, 2023 based on unit availability.

Period	Gen 1	Gen 2	Gen 3	Gen 4	Total (MW)
A	O	0	140	142	282
B	O	36	39	42	117
C	57	0	0	60	117
D	20	0	0	20	40
E	54	57	0	66	177
F	38	0	40	0	78
G	0	114	126	0	240

To obtain the cost for the committed units of the generation plant using the unit production cost for the month of September, 2023 based on unit availability will be given as:

$$Period\ Cost = (summation\ of\ the\ cost\ of\ each\ commited\ unit) \times Duration\ in\ hrs$$

Table 5: Unit commitment table of a day peak production in May, 2024 showing number of committed generation and production.

Period	Duration	Total time	Gen 1	Gen 2	Gen 3	Gen 4
A	12am-7am	7	0	1	1	0
B	7am-9am	2	0	1	1	1
C	9am-12pm	3	0	1	1	1
D	12pm-1pm	1	0	1	1	0
E	1pm-4pm	3	0	1	1	0
F	4pm-6pm	2	0	1	1	0
G	6pm-12am	6	0	0	1	0

Table 6: The periodic power produced by individual generator in a daily peak load in May, 2024 based on their cost function.

Period	Gen 1	Gen 2	Gen 3	Gen 4	Total (MW)
A	O	76	105	0	181
B	O	36	35.6	20	91.6
C	0	70.4	57	45	172.4
D	0	17.6	20.2	0	37.9
E	0	49	60.6	0	109.6
F	0	40	38	0	78
G	0	0	111	0	111

IV. RESULTS AND CONCLUSION

Table 7: Calculated result for September, 2023 based on unit availability.

Unit committed	Duration (hrs.)	Cost of operation (₦)
3+4	7	106,928,920
2+3+4	2	43,362,880
1+4	3	49,522,380
1+4	1	49,522,380
1+2+4	3	16,507,460
1+3	2	68,740,020
2+3	6	82,783,680
TOTAL	24	399,874,740

This method of generator scheduling and commitment was based on the operational readiness or availability of the various committed units at a particular period. The coordination and supply of power during this period resulted in a large cost incurred by the generating plant. The total operating cost was calculated to be ₦399,874,740 in the month of September 2023.

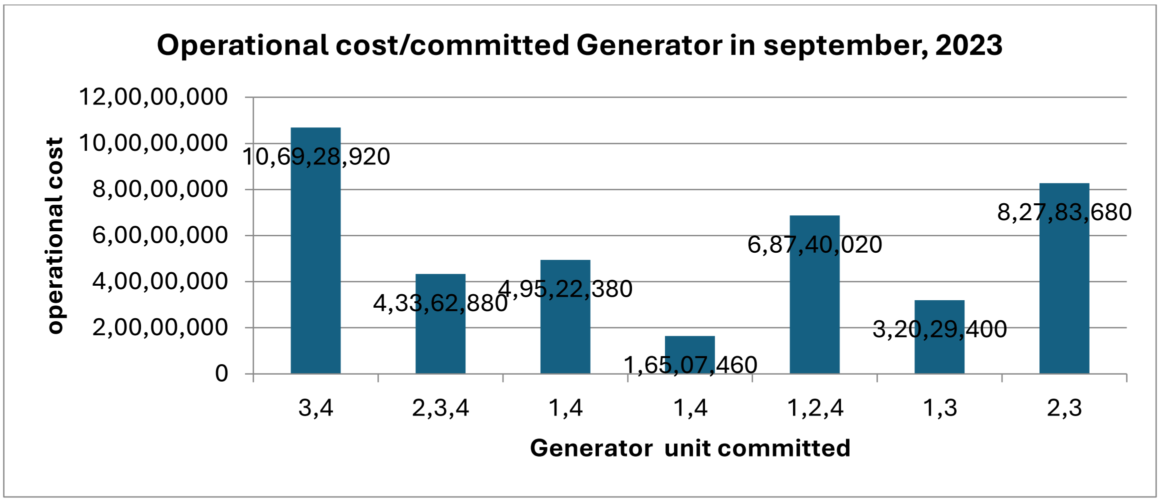

Figure 2: Operational cost behaviour /committed generator representation for September, 2023 based on unit availability.

Table 8: Calculated result for May, 2024 based on the cost function of each unit.

Unit committed	Duration (hrs.)	Cost of operation (₦)
2+3	7	96,580,960
2+3+4	2	43,362,880
2+3+4	3	65,044,320
2+3	1	13,797,280
2+3	3	41,391,840
2+3	2	27,594,560
3	6	44,348,400
TOTAL	24	332,120,240

The scheduling and coordination of the generating unit in the month of May, 2024 was carried out considering the cost of operation of each generating units in other to maximize generation and minimize the overall operating cost of the system. The total operating cost was calculated to be ₦332,120,240.

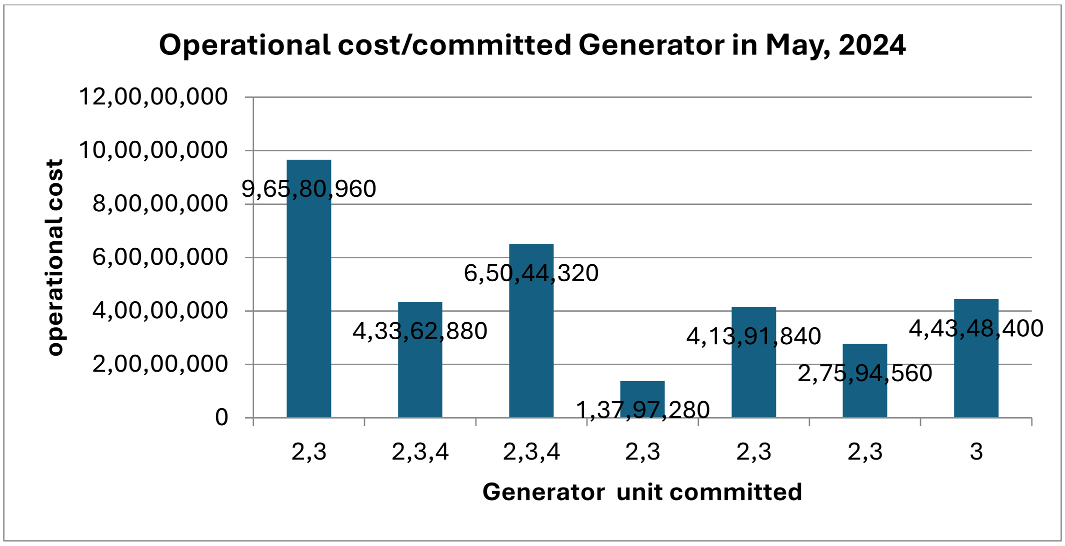

Figure 3: Operational cost behaviour /committed generator representation for May, 2024 based on cost function.

Comparing Results

Based on the result obtained from the scheduling and coordination of the 4 generating units in the month of September, 2023 and May, 2024.the result obtained in terms of the operational cost of scheduling the 4 generators in the month of September, 2023 was ₦399,874,740 while that of the month of May, 2024 was ₦332,120,240. The results shows that the method of scheduling and coordination of the 4 generators in the month of May, 2024 which was carried out considering the cost function of each unit reduced the operational cost by 17% (₦67,754,500) and also provides best reliable and economical method of generation coordination. For scheduling and coordination of reliable and economical power supply based on the method used which is the lagrangian relaxation cost equation, the best coordination of the 4 generators should be done in the order below which is in respect to the cost function of the respective unit.

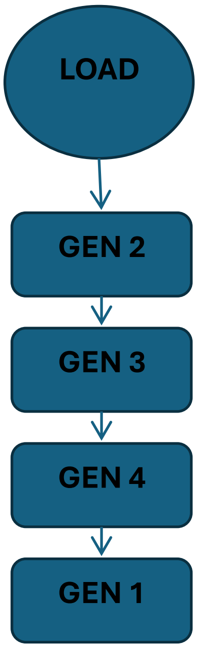

Figure 4: Order for Generator Coordination and Scheduling

V. CONCLUSION

The use of lagrangian relaxation cost equation for optimization and scheduling of power generation coordination for an economical supply of power from FIPL have proved to be realistic and adequate in ensuring reliability to power production or distribution by improving the day-to-day scheduling through proper implementation by power plant operators. It has also been proved as a means through which proper power management can be achieved thereby facilitating the reduction in operational cost of production by ₦67,754,500 which is 17% when proper scheduling of the generation plant is carried out while considering a least cost of production through strategic combination pattern of the committed unit.

ACKNOWLEDGEMENT

We are sincerely grateful to God Almighty, our parents, siblings and friends for all their support and guidancethroughout the period of this undergraduate project work.

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