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A Least Cost Approach for Power Plant Portfolio Optimization in a Regulated Environment Electricity Supply Industry with Constraints

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Abstract *– Similar to other countries, in Malaysia, the daily demand exhibits large variations between weekdays and weekend and between peak and off peak hours. The ability to follow the load demand with reliable supply of electricity and optimal economic operation is of paramount importance, which is achieved by solving two power system scheduling problems, namely, unit commitment and economic dispatch. This paper proposes a hybrid method combining priority listing and dynamic programming as the solution tool for this study, with an ultimate objective of obtaining a least cost solution for the short-term scheduling period considered subject to unit and system constraints. An interactive model built using Microsoft Excel-VBA Macro program was used to perform simulations and analyses on small scale system consisting of four gas-fired units and two coal-fired units. The optimal solution for the system studied was achieved under a reasonable processing time. The least cost solution was found by using feasible combination of units that satisfies all constraints and with total minimum fuel cost, start-up cost and variable operating cost. Higher utilization of the more efficient units is a vital factor to achieve the least cost objective.*

Keywords – *Dynamic programming, economic dispatch, priority listing, portfolio optimization and unit commitment.*

1. INTRODUCTION

The advances of science and technology have completely transformed the electricity supply industry into a more complex environment that no longer operates under the simple philosophy of supply follows demand. In addition, the non storage characteristics of electricity together with the increasing fuel costs worldwide further call for the need to ensure the provision of electricity is not only adequate and secure but also cost effective.

In order to satisfy all these requirements, power systems short term scheduling is formulated such that the load demand at each period of time is supplied in a least cost manner while satisfying both unit and system constraints such as minimum up and down time, ramp rate limits, spinning reserve and other energy requirements. This is achieved by finding the optimal solution for two key problems of power system scheduling, namely, unit commitment and economic dispatch.

Unit commitment seeks to determine the on/off states of the units in the system to meet the load demand at each time period subject to operating constraints [1]. On the other hand, economic dispatch is the process of deciding the individual power output of the scheduled generating units at each time period to ensure system load is supplied in a most economic way [2].

These problems may look simple. However, they are extended in a number of ways due to the large variations in the demand between weekdays and between peak and off peak hours. The problems become even challenging considering the astronomical number of possible combinations of the start-up and shut-down of all the generating units in the system. A proper planning and scheduling is essential to ensure a feasible solution that has least cost generation is achieved.

The objective of this paper is to present the analyses and results of portfolio optimization simulation for a small scale system consisting of six thermal generating units running on different fuel source. Except for the small number of generating units, the system bears a close resemblance to the existing Malaysian power system. An interactive model built using Microsoft Excel-VBA Macro program has generated various combined schedules of unit commitment and economic dispatch for a day that satisfies all constraints. The feasible solution that has the least generation cost is then selected to provide the generation schedule for the day.

2. PORTFOLIO OPTIMIZATION AND CONSTRAINTS

Portfolio optimization aims to solve the problem of unit commitment and economic dispatch based on a portfolio approach instead of a standalone approach by considering all the generating units in the system. In a regulated market, it seeks to optimize profitability by strategizing the operations of power producer such that fuel is converted into electricity in a least cost manner [3]. Minimization of operation costs which is inclusive of fuel, start up and variable operation and maintenance costs while satisfying a set of system constraints is the ultimate objective of this optimization [4].

$$C_i(P_{i,t}) = \min \sum_{i=1}^{N_n} \sum_{t=1}^{N_t} [J_{i,t} F_i(P_{i,t}) + J_{i,t}(1 - J_{i,t-1}) S_i(X_{i,t-1}^{off}) \tag{1}$$

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where:

$C_i(P_{i,t})$ - cost of producing power P of unit i at hour t

$J_{i,t}$ - commitment state (on/off) of unit i at hour t

$F_i(P_{i,t})$ - fuel cost of unit i at hour t

$S_i(X^{off}_{i,t-1})$ - start up cost unit i after being offline for $X^{off}_{i,t-1}$ hours

N_t - number of hours in the study period considered

N_n - number of units considered

2.1 Operation Costs

The fuel cost, as the name suggests it, is dependent on the amount of fuel consumed by the generating unit to produce power sufficient to meet the load demand. Depending on the type of thermal technology, changes in fuel price could have significant impact to the total operating costs as illustrated in Figure 1 [5]. In plants powered by natural gas, fuel component may represents as much as 70 percent of the total operating costs that a small improvement in the optimization function is said to lead to significant fuel cost savings amounting to several billions of dollars [6], [7]. This improvement can be viewed in terms of optimal distribution of the load among the more efficient units to minimize the operating or fuel costs. To illustrate this point, consider the following hypothetical example. A system consists of a combined cycle unit and an open cycle unit with a nominal capacity of 200 MW each and operating at 100% load. Both the units are running on natural gas at a market price of RM 35 per mmBtu. It could be observed in Table 1 that the more efficient unit consumes less fuel to produce the same kWh of electricity and as such, contributes to a lower fuel cost. Based on this example, there is a saving of RM 290 million per annum by utilizing the more efficient unit to supply the load.

The start-up cost, on the other hand, is incurred only when a transition from off state to on occurs, even before any actual electricity generation. It is the cost related in bringing a unit on-line and is dependent of the prevailing temperature of the boilers [8].

For ease of analysis, the start-up cost is assumed to be a fixed cost component and could be categorized into three types, namely, hot, warm and cold start up costs, which are related to the down-time period of the generating unit. A cold start up will be incurred if the thermal unit has been off for a long period. If the unit has been recently turned off (temperature of the boiler is still high), a hot start-up cost is applied. The cold start up cost is normally more expensive as compared to the hot and warm. The down-time duration for each of the start-up type is given in Table 2.

Variable cost is related to the operation and maintenance of the unit and varies with operating hours. An important element of this cost is the yearly maintenance and overhauls that are carried out to reduce catastrophic failures that may severely impact the reliability of the units.

Table 1. Fuel cost savings due to utilization of a more efficient generating unit.

Plant	Efficiency	Btu/kWh	MWh	mmBtu	RM billion
CCGT	55%	6200	1,752,000	10,862,400	0.38
OCGT	31%	11000	1,752,000	19,272,000	0.67
				Difference	0.29

Table 2. Types of start-up and down-time duration.

Type of Start-Up	Down-time duration
Hot	Less than 8 hours
Warm	Between 8 to 48 hours
Cold	More than 48 hours

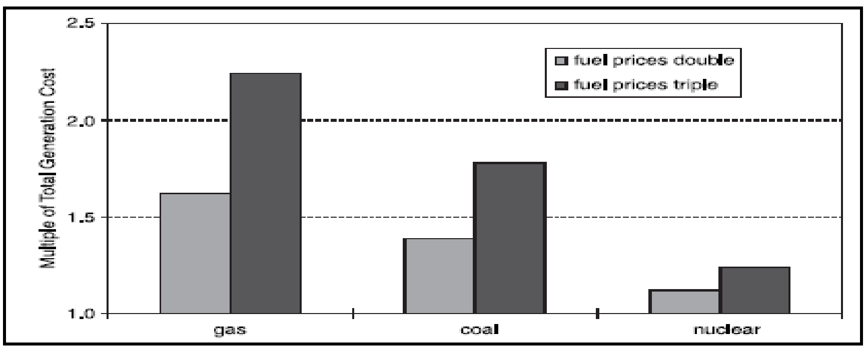

Fig. 1. Effect of fuel cost on total operating cost.

2.2 Operational Constraints

Besides satisfying the minimum operational cost criteria, the optimization process needs to satisfy a range of constraints, as the followings:

- System power balance - the total power generated and the total demand must be in balance during all period of time

$$\sum_{i=1}^{N_n} P_{i,t} = D_t \qquad (t = 1,\ldots,Nt) \qquad (2)$$

where,

$P_{i,t}$ - power generated by unit i at hour t

D_t - system load demand at hour t

- System spinning reserve requirement – most system imposes a spinning reserve requirement so that any unforeseen events due to generation failure and sudden increase in demand could be resolved reliably. As such, the total power generated must be sufficient to meet the total demand and generating units spinning reserve requirement. Spinning reserve is defined as total amount of generation available from all units spinning on the system, minus the current load and losses being supplied [9].

$$\sum_{i=1}^{N_n} \overline{P}_i J_{i,t} \geq= D_t + SR_t \qquad (t = 1,\ldots,Nt) \qquad (3)$$

where,

$\overline{P}_i$ - rated upper generation limit of unit i

SR_t - system spinning reserve requirement at hour t

- Unit generation limits – all generating units have both upper and lower generation limits that need to be considered at all time during operations.

$$\underline{P}_i \leq P_{i,t} \leq \overline{P}_i \qquad (t = 1,\ldots,Nt,\ i = 1,\ldots,Nn) \qquad (4)$$

where,

$\underline{P}_i$ - rated lower generation limit of unit i

- Unit minimum up and down times – during start-up and shut down, all generating units are subjected to a minimum period of time before they could be shut down or started up again. In other words, once the generating units are running, they should not be turned off immediately and vice versa.

$$(X_{i,t-1}^{on} - UT_i) * (J_{i,t-1} - J_{i,t}) \geq 0 \qquad (5)$$

$$(X_{i,t-1}^{off} - DT_i) * (J_{i,t} - J_{i,t-1}) \geq 0 \qquad (6)$$

where,

$X_{i,t}^{on/off}$ - time duration at which unit i has been on online/offline state at hour t

UT_i - minimum up time of unit i

DT_i - minimum down time of unit i

- Ramp rate limits (applicable for dynamic economic dispatch problem) – all generating units have upper and lower ramp rate limits that need to be considered at all time during operations. Abrupt changes to unit capacity during starts up or shuts down need to be within the lower and upper limits of the ramp rates. During starts up and shuts down,

$$\overline{P_{i,t}} - \overline{P}_{i,t-1} \leq RU_i \quad \text{as unit i starts up} \qquad (7)$$

$$\overline{P_{i,t-1}} - \overline{P}_{i,t} \leq RD_i \quad \text{as unit i shuts down} \qquad (8)$$

where,

RU_i - ramp up rate limit of unit i

RD_i - ramp down rate limit of unit i

As unit generation changes,

$$P_{i,t} - P_{i,t-1} \leq RU_i \quad \text{as generation increases} \qquad (9)$$

$$P_{i,t-1} - P_{i,t} \leq RD_i \quad \text{as generation decreases} \qquad (10)$$

3. PROBLEM FORMULATION

Malaysia's economy has been growing steadily in the last several decades. In line with this positive outlook, the future demand for electricity is expected to increase significantly as well. As illustrated in Figure 2, the peak demand for Peninsular Malaysia in 2008 was 14,007 MW, which was met reliably with installed capacity of approximately 19,732 MW [10]. With an excess reserve margin of approximately 41%, the current installed capacity would comfortably cater for the projected demand growth over the next few years without the need for additional capacity. Hence, the existing amount of capacity generated using various types of fossil fuel such as natural gas, coal and oil need to be optimized to ensure reliable operations and continuous power supply at minimum cost.

Furthermore, the surge in fuel prices is also a concern as without proper planning and scheduling, there could be tremendous hikes in the electricity generation cost. Presently in Malaysia, for electricity sector, natural gas is the predominant fuel, followed by coal, hydro and oil. However, relying heavily on natural gas is risky, similar to the conditions experienced in the '70s where the country was too dependent on oil resources. As shown in Figure 3 [11], production from existing gas fields in Malaysia are depleting and without the development of new reserves, natural gas may need to be imported. It is essential to identify a least cost dispatch that mitigates the risk of supply while maintaining the power system security.

4. METHODOLOGY AND ASSUMPTIONS

For a given N number of units, in an hour, there are (2N-1) states which represent the combination of unit statuses. Hence, for a six-unit system considered for this study, there should be sixty three states in an hour. For the scheduling period of twenty four hours, the total possible combination increases to 1.58 x 10^{43} which would require a very large processing time. This may be solved using the priority listing method as the computation time and memory requirement are fairly modest for a large system. However, the method may not be accurate as the state transition costs are not taken into account in finding the optimal solution for the problem. Furthermore, this method is restricted to systems where the unit curves are linear from zero to full load and the start-up costs are independent of the units' offline time [9]. Alternatively, the dynamic programming method may be considered to provide an optimal solution for the portfolio optimization problem. However, the method may work only for a system with limited number of units. The computational complexity of the dynamic programming method increases exponentially with the dimensionality of the state, hence making it impractical for large scale systems. In order to solve this curse of dimensionality problem, a hybrid method between priority listing and dynamic programming is used as the solution tool for this study. The method takes into account the system and unit constraints with the objective of finding an optimal economic solution.

The algorithm is designed in two stages. First, the priority listing method is used to provide a preliminary ON/OFF scheduling table. A ranking order is formed based on ascending generation cost which is inclusive of fuel, variable and start-up costs. If a generating unit is shut down, it is clearly not able to produce any power. Hence, all unavailable units are excluded from the priority list. For units that are running, operating costs comprising of fuel and variable costs are considered. For units that are subject to start-up, the total cost comprises of start-up cost and operating costs, making the units having a higher cost as compared to other units that are running, as illustrated in Figure 4. Assuming there are three different generating units, U1, U2 and U3 with different start-up costs and variable costs. U1 is unavailable; hence it would be excluded from the priority list. U3 would be supplying most of the load as it is running and cheaper than U2 which is subject to start-up cost. In terms of priority order or often known as merit order ranking, U3 is ranked higher than U2 in the hour studied.

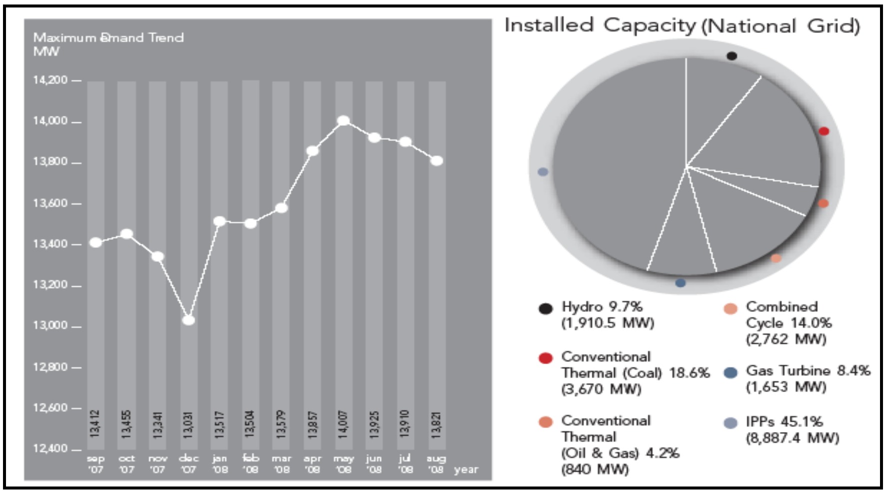

Fig. 2. Maximum demand and installed capacity in year 2008.

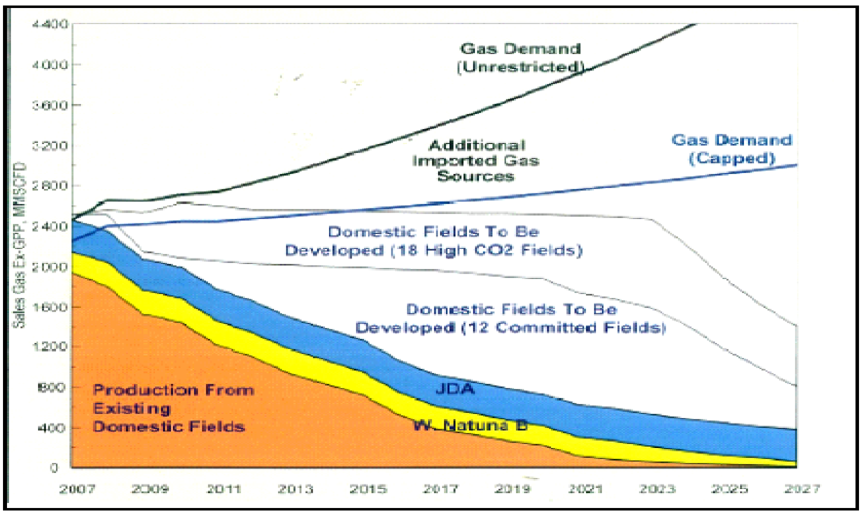

Fig. 3. Depleting source of indigenous fuel in Malaysia.

The dynamic programming method is then used to fine tune the schedule in response to hourly load changes. It decomposes the multistage twenty-four hour problem into a series of single hour problem. It develops an optimal solution to the original twenty-four hour problem by solving the single hour problem step-by-step successively. In cases where there is no feasible solution found for the single hour, the solution proposed is eliminated and hence, will not be considered to solve the multistage problem.

The hybrid method employed provides solution within reasonable processing time. Figure 5 illustrates the dynamic programming method used in solving the portfolio optimization problem.

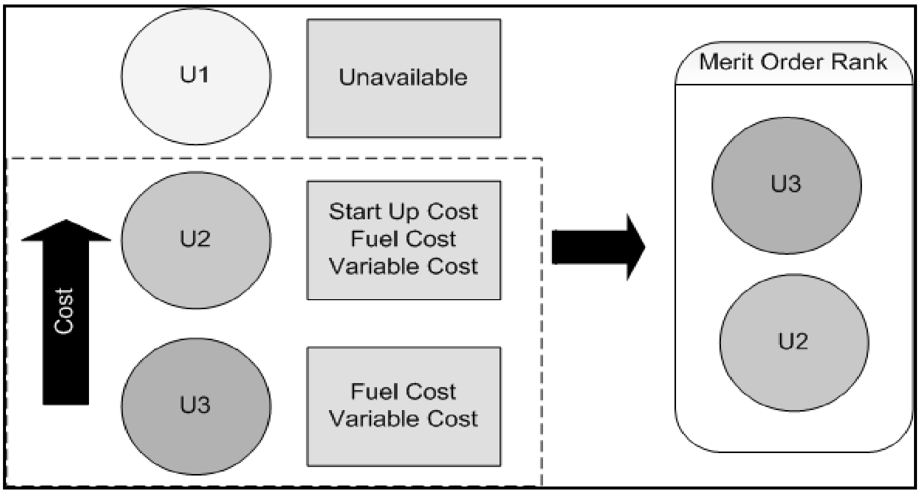

Fig. 4. Priority listing method.

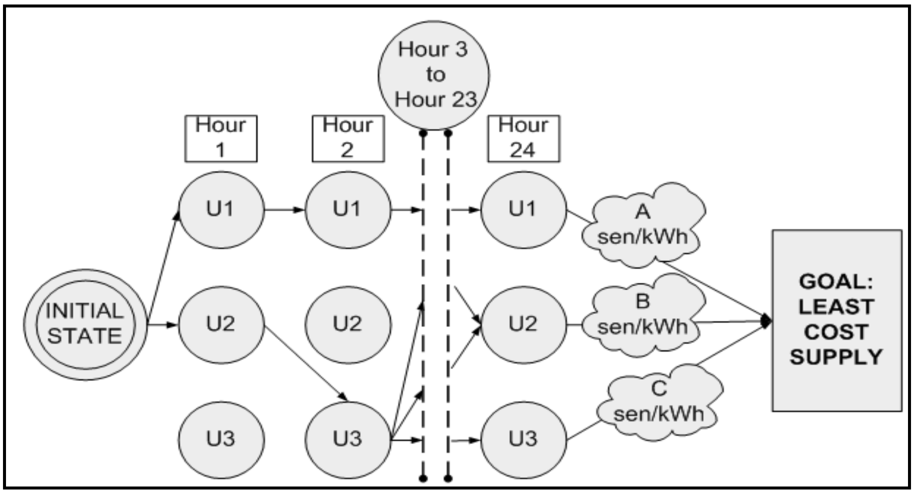

Fig. 5. Dynamic programming.

The model developed consists of six units of which four are gas-fired units and the remaining two are coal-fired units. The gas-fired units use natural gas as the primary fuel. The two steam units, C1 and C2 are powered using coal of different sources, hence having different coal prices. The operating characteristics of the units are defined in **Error! Reference source not found.**.

In Peninsular Malaysia, following a tariff revision carried out by government in March 2009, the subsidized natural gas price was increased from RM 6.07/GJ to a pegged value of RM 13.55/GJ and then reduced to RM 10.14/GJ. Coal prices are based on mutual negotiations between the national utility company and the power producers with reference to benchmark prices. Table 4 provides the assumed fuel price for this study. The total cost at base load operations is also provided in the table.

Table 3. Unit operating characteristics.

Unit	Max Capacity (MW)	Min Capacity (MW)	Min Up Time (hour)	Min Down Time (hour)	HR Min Load (kJ/kWh)	HR Base Load (kJ/kWh)
GT11	200	70	4	2	12825	11070
GT12	250	90	5	3	11780	9796
GT13	300	105	5	4	10450	8250
GT14	400	140	3	2	9215	6693
C1	500	180	10	10	13320	11273
C2	700	210	9	9	11760	9791

Table 4. Unit total cost at base load.

Unit	Fuel Type	Fuel Price (RM/GJ)	Fuel Cost (sen/kWh)	Variable Cost (sen/kWh)	Total Cost (sen/kWh)
GT11	Gas	10.14	11.23	1.55	12.78
GT12	Gas	10.14	9.94	1.83	11.77
GT13	Gas	10.14	8.37	1.60	9.97
GT14	Gas	10.14	6.79	1.77	8.56
C1	Coal 1	16.242	18.31	1.30	19.61
C2	Coal 2	13.535	13.25	1.10	14.35

5. ANALYSIS AND RESULTS

Various combinations of unit commitment schedule are simulated for the selected short term scheduling period of one day (24 hours). In this study the possible number of combinations for one hour period is sixty three such that any one unit or combination of units would be subjected to shut down. By using the hybrid method which takes into consideration the constraints such as system power balance and spinning reserve requirement, the number of feasible solutions reduces to eight, with the details provided in Table 5. The combination that has the least generation cost would be selected to provide the generation schedule for the day.

For the period selected, the maximum and minimum demands are 1112 MW and 816 MW respectively, as shown in Figure 6. The values are within the total capacity limit of the generating units.

Units that are not on outage are listed in the merit order based on prioritization concept. However, due to spinning reserve requirement, maximum capacity from each unit that is available for dispatch has been limited to certain value below the actual dependable capacity of the unit, as shown in Table 6. The reserve is calculated such that it is capable of making up the loss of the most heavily loaded generation unit in a given period of time, which for the day selected is 700 MW.

All the available units are sorted based on ascending order according to the units' total cost which comprises of fuel cost, start-up cost and variable operating cost. Unit with the lowest operating cost would be ranked the highest in the merit order. Since there was no start-up assumed, the start-up cost for all the units is assumed zero. The merit order listing for this study is shown in Figure 7.

The base case follows the business as usual method of which all the units are committed for the entire day. The economic dispatch is performed such that the unit with the least cost would be providing the most out of the unit's available capacity less spinning reserve requirement which is termed as Capacity Available for Dispatch (CAFD) while the most expensive unit would be running at minimum level. GT11, C2 and C1 being the three most expensive units would be supplying close to their minimum load while the cheaper units would be dispatched close to their CAFD, as shown in Figure 8.

As the demand varies over the hourly period due to the grid constantly being in state of flux, the load supplied need to be altered frequently to match the level of consumption accordingly. In certain period of time, it decreases to a level where one or more generating unit is able to be turned off. This option is considered as one of the optimization for the base case. As indicated in Table 5, Case 1, 2, 3 and 4 deals with the scenario whereby one gas fired generating unit is turned off. Case 5 and 6 study the option of turning off one of the coal units. In Case 7 and Case 8, two gas fired units are subject to shut down. A combination shut down of one coal-fired unit and one gas-fired unit or two coal-fired units at one time is not permissible as it violates the condition of power balance where there would be insufficient supply to meet the demand and reserve requirement at certain hours of the scheduling period.

Table 5. Feasible solutions.

Scenario	Optimization Case	Unit Commitment Schedule (On-1/OFF-0 Status)					
		GT14	GT13	GT12	GT11	C2	C1
Base Case	Base	1	1	1	1	1	1
One Gas-fired Unit Shut down	1	0	1	1	1	1	1
	2	1	0	1	1	1	1
	3	1	1	0	1	1	1
	4	1	1	1	0	1	1
One Coal-fired Unit Shut down	5	1	1	1	1	1	0
	6	1	1	1	1	0	1
Two Gas Unit Shut down	7	1	0	1	0	1	1
	8	1	1	0	0	1	1

Table 6. Reserve requirement for base case.

Unit	Max Capacity (MW)	Min Capacity (MW)	Available Capacity for Dispatch (MW)	Reserve Requirement (MW)
GT11	200	70	140	60
GT12	250	90	176	74
GT13	300	105	211	89
GT14	400	140	281	119
C1	500	180	351	149
C2	700	210	491	209
		Total	1650	700

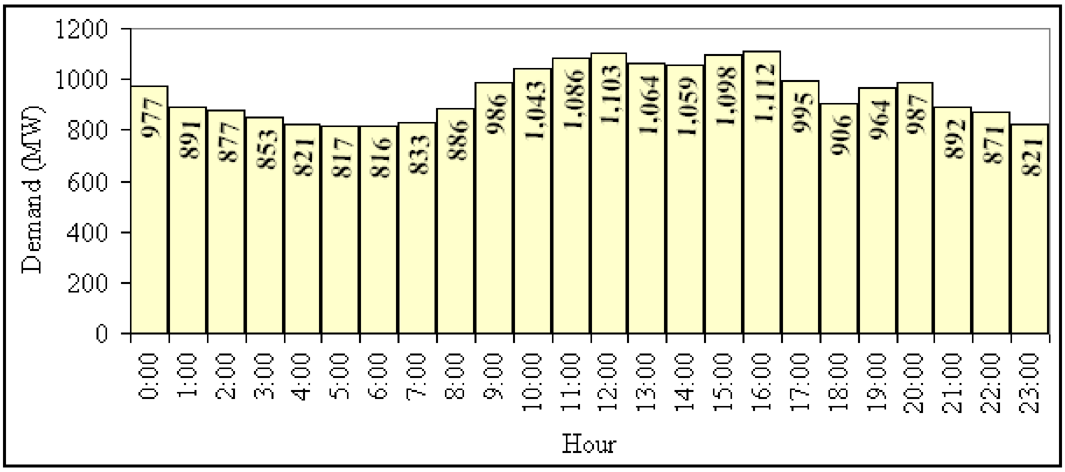

Fig. 6. Load demand.

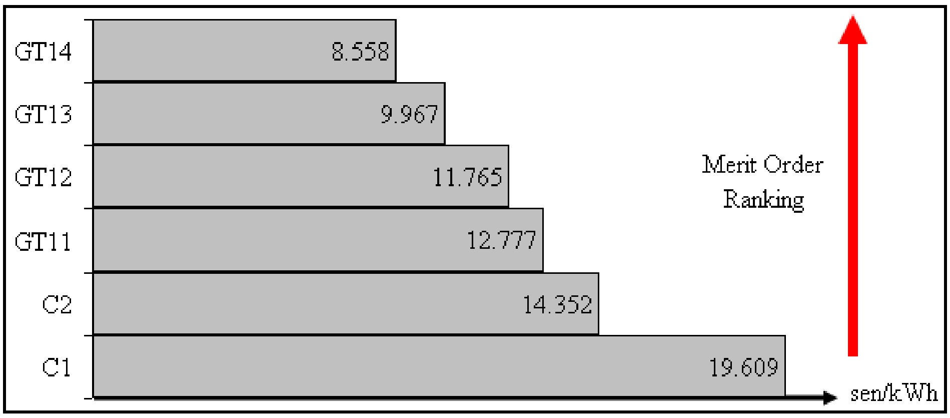

Fig. 7. Merit order listing.

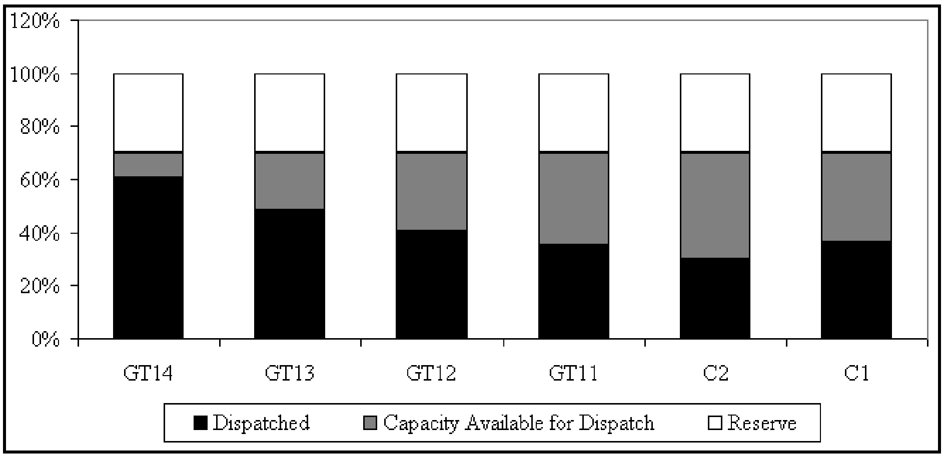

Fig. 8. Economic dispatch stack for base case.

Based on the simulations performed, it could be observed that as compared to the base case, only five cases produced an optimized result by reducing the total generation cost in the range of 1.49% to 12.51%.

The most optimized result is produced in Case 5 which involve the shutting down of the most expensive coal unit, C1 for the entire scheduling period. The spinning reserve is automatically adjusted such that the remaining units would provide for the spinning reserve requirement where the value from each unit is increased to 37.84%. As observed in Figure 9, GT14 and GT13 are supplying at their maximum CAFD while load supplied by the remaining units had also increased, resulting in a reduced total cost of generation at 12.94 sen/kWh.

In terms of absolute value, for the selected load profile, there is a difference of RM 421,393 per day, as shown in Table 8. In other words, assuming a similar load as shown in Figure 10, the optimization carried out provides a savings of approximately RM 154 million per annum as compared to the routine or business as usual method.

The results generated shows that by having lesser generating units online, least cost dispatch could be achieved. However, it is dependent on the type of units that are turned off. In the cases studied, shutting down of the expensive coal-fired unit provides a more feasible solution as compared to shutting down one or more gas-fired units. Running coal-fired units at part load comes with a heavy price.

Table 7. Base case optimization results.

Scenario	Optimization Case	Unit Commitment Schedule (On-1/OFF-0 Status)						Generation Cost (sen/kWh)
		GT14	GT13	GT12	GT11	C2	C1	
Base Case	Base	1	1	1	1	1	1	14.79
One Gas-fired Unit Shut down	1	0	1	1	1	1	1	15.38
	2	1	0	1	1	1	1	14.38
	3	1	1	0	1	1	1	14.57
	4	1	1	1	0	1	1	14.51
One Coal-fired Unit Shut down	5	1	1	1	1	1	0	12.94
	6	1	1	1	1	0	1	13.60
Two Gas Unit Shut down	7	1	0	1	0	1	1	15.04
	8	1	1	0	0	1	1	14.57

Table 8: Total generation cost comparison for base case and optimized case.

Net electrical output=22,778,000 kWh	Generation unit cost (sen/kWh)	Total Cost (RM)
Base Case	14.79	3,368,866
Optimized Case	12.94	2,947,473
Difference		421,393

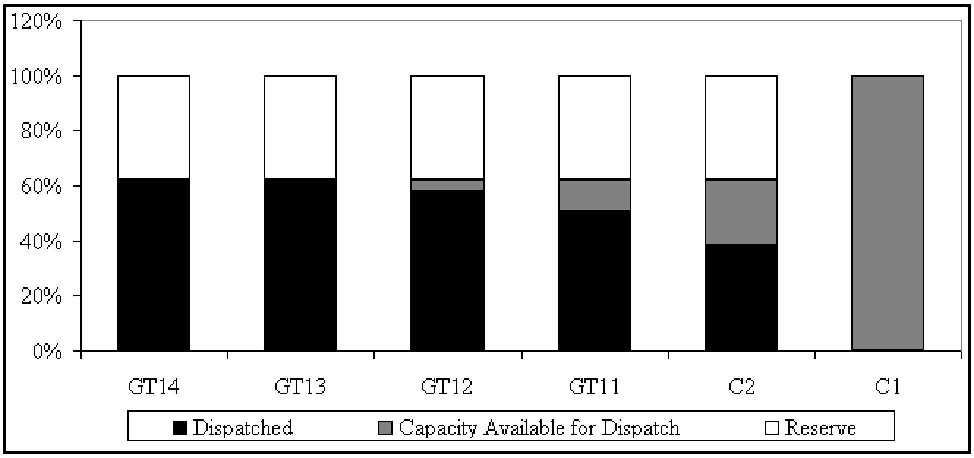

Fig. 9. Economic dispatch stack for Case 5.

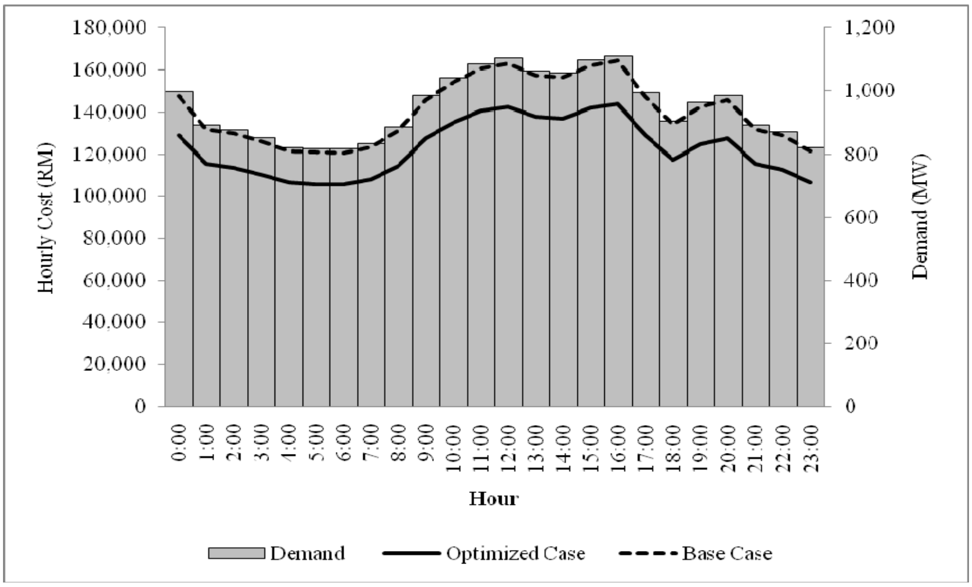

Fig. 10. Hourly generation cost for base case and Case 5.

6. CONCLUSION

A program built using Microsoft Excel-VBA Macro has been successfully developed and executed to perform the unit commitment and economic dispatch simulations involving various scenarios of portfolio optimization as discussed in the previous sections. The processing time of the program was reasonable due to the elimination of infeasible solutions, hence leaving only feasible solution to be processed to solve the multistage problem. However, it should be noted that the hybrid method worked well for a small scale system but may not be able to perform similarly when it comes to a large scale system involving hundreds of generating units. The curse of dimensionality would limit the ability of the method to solve problem involving large variables. In order to reduce the complexity of the problem, the method had also assumed that the system is free of transmission congestion and hence, limited to such cases. In reality, for a practical system, the transmission congestion is a constraint and should be considered in the analysis.

Despite the drawbacks addressed, the analysis and optimization performed using the hybrid method managed to seek the least cost energy production for the small scale system studied in a given period. Few scenarios studied showed that the most optimum cost could be achieved by using more efficient generating units to supply the load demand. This is supported with higher utilization of the generating units that minimized the fuel consumption per kWh generation and in return, ensured a lower cost of production. This corresponds to the concept of utilization whereby a plant with low utilization inevitably has a high unit cost of production because the same investment and fixed costs of operation and maintenance are recovered over fewer units of production.

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