

Optimal Scheduling of Limited Energy Units Using Deconvolution Technique: A Case Study of Hydro Power Generation in Thailand

K. Chayakulkheeree, A. Kamglar, P. Liengpradis, and S. Juanuwattanakul

Department of Electrical Engineering,

Faculty of Engineering, Sripatum University, Bangkok 10900, Thailand

Phone 0-2579-1111 Ext. 2272, Fax 0-2579-1111 Ext. 2147, Email: keerati@spu.ac.th, auyporn@spu.ac.th

Abstract

This paper investigates a practical application of deconvolution technique base optimal scheduling of limited energy units (LEUs). The computer program has been developed so that the probabilities of unit outages are taken into account by capacity model building and deconvolution technique is used to determine the optimal scheduling of LEUs. The program has been tested with the equivalent Thai power system with 110 power generating units, including 16 LEUs (hydro plants). The results shows that the deconvolution technique based optimal LEUs scheduling can dispatch all of daily energy specified at the optimal condition leading to the lower daily operating cost than that of scheduling without deconvolution calculation. The method can effectively associate the unit commitment problem as a preliminary scheduling of LEUs.

Keywords: energy limited unit, capacity model building, equivalent load duration curve, convolution, deconvolution

1. Introduction

In power generation scheduling, the operating costs of the units can found by loading the units under their corresponding equivalent load duration curves (ELDCs) according to the fuel cost and computing the energy generated by each unit [1]. The algorithm can easily be implemented if the energy generated by each unit is not limited and its operating condition is only based on its generating capacity and availability, for example, coal-fired, oil fired, gas turbines and nuclear units. However, there are units whose energy is constrained by some other factors. Such units are categorized as limited energy units (LEUs) or assigned energy (AE) units. In case of hydroelectric plant, this constraint may be due to limited reservoir size, run-of-the-river constraint or seasonal rainfall limitation. The cost associated with production of this energy is typically very low and it is most advantageous to use all of the available energy. In case of a fossil fueled units, the constraint may be due to limited fuel supply or the limits on emissions. In case of nuclear, the constraint may be due to insufficient core energy which prevents the unit being run on base load. Beside this energy constraint, the LEUs are also limited by its generating capacity and availability.

In Thailand, the electricity supply industry is presently a vertically integrated structure. The Electricity Generating Authority of Thailand (EGAT) owns and operates transmission network and most of the generations.

The Metropolitan Electricity Authority (MEA) and the Provincial Electricity Authority (PEA) own and operate geographical distribution systems. Since 1990, the private investment in the generation sector through small power producers (SPPs) and independent power producers (IPPs) programs has been successfully introduced. Both SPPs and IPPs sell the electricity to EGAT based on the long term power purchase agreements (PPAs). EGAT is a single buyer who subsequently sells the electricity to MEA, PEA and limited number of direct consumers. Fig. 1 shows the structure of the present Thai power system. As of fiscal year 2001, hydro power shares about 13% of total power generation in Thailand as shown in Fig. 2 [2]. In Thailand, hydro power plants scheduling are strictly based on irrigation requirement. The reservoirs discharge volumes are specified by the Royal Irrigation Department (RID) on daily basis. Therefore, hydro power plants can be modeled as the LEUs and it is productive to develop the tool for optimal scheduling of the hydro generating units.

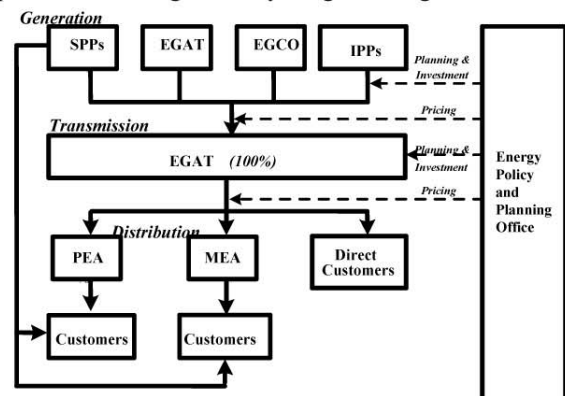


Fig. 1 The structure of present Thai power system

Many techniques have been proposed to determine optimal scheduling of LEUs in power systems. Bloom [3] proposed an iterative decomposition type framework where reservoir utilization decisions were made by linear programming master problem and associated marginal costs and benefits were evaluated by a subproblem. The algorithms required multiple solution of subproblem to find the optimal usage of reservoirs. Some heuristic and artificial based optimization techniques have also been applied to solve the optimal hydro-thermal scheduling [4-8]. However, the probabilities of the unit outages are not included in the problem formulations. To incorporate the probabilities of the unit outages into optimal hydro generating units scheduling, the algorithm to optimize the reservoir utilization by probability

production costing has been proposed by Malik and Cory [9]. Nevertheless, the framework for applying the technique to practical problems has not been fully developed due to its intensive mathematical computation.

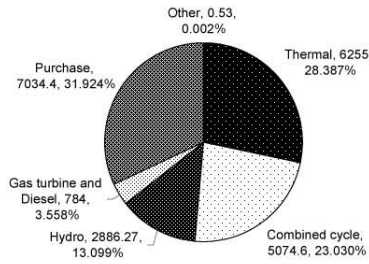


Fig. 2 Thai power generation classified by type of power plant (units in MW)

In this paper, the program for computing the capacity model building and deconvolution for large generation systems is developed. The deconvolution technique is applied to determine an optimal daily scheduling of hydro power plant. The hydro generating units are model as LEUs. The energy specified of each hydro unit is compared with the calculated expected energy served (EES) to determine an optimal scheduling condition. The method is compared to the daily scheduling without deconvolution process.

2. Problem Formulation for Optimal Scheduling of Energy Limited Units

2.1 A Recursive Algorithm for Capacity Model Building

With merit order operation, if generating units were completely reliable and thus always available when called upon to generate, the areas occupied by each unit under the original load duration curve (LDC) would be sufficient to determine unit specific generated energy. However, generating units are unanticipatedly forced out of service resulting in increased calls for generation on units higher in the merit order.

The increased demand for generation by a specific unit resulting from the forced outage rates (FOR) of all previously loaded units is accounted by modifying the LDC to reflect these forced outages. This is accomplished by computing the equivalent load on a particular unit which is the sum of customer demand and forced outage of previously loaded generators. The cumulative probability distribution, or ELDC, gives the total probability that customer load plus the capacity on forced outage equals or exceeds a given value X when the generating system through the i th unit out of NG total units is being considered.

Each time a unit is loaded, its forced outages have to be added to the current ELDC to derive the new ELDC which reflect the demand seen by the next unit in the merit order. This addition depends on the probability distribution characterizing the forced outages the unit. After the outages

of all available units have been added to the customer load, the EENS may be obtained as an area under the resulting ELDC, thus providing a measure of system reliability. The height of the same curve at the capacity point of the system is the loss of load probability (LOLP), that is, the expected proportion of time that customer demand may exceed available generating capacity.

By a recursive algorithm for capacity model building [1], the cumulative probability of a particular capacity outage state of X MW or the equivalent load duration curve, after a unit generating at P_{Gi} MW and force outage rate FOR_i is considered, is given by,

$$ELDC_i(X) = (1 - FOR_i) \cdot ELDC_{i-1}(X) + FOR_i \cdot ELDC_{i-1}(X - P_{Gi}), \quad (1)$$

where,

P_{Gi} = the real power generation of unit i (MW),

$ELDC_i(X)$ = the equivalent load duration curve when the unit i is considered,

$ELDC_{NG}(X)$ = the equivalent load duration curve when all units are considered,

$ELDC_0(X) = LDC(X)$ = the original system load duration curve,

FOR_i = the FOR of generator i , and

ST = the step size used in the calculation (MW).

Appendix A illustrates the probability table of the recursive algorithm for capacity model building. To generalize the algorithm, the step size (ST) used in this paper is one MW. Fig. 3 shows the ELDC after taken into account the units FOR.

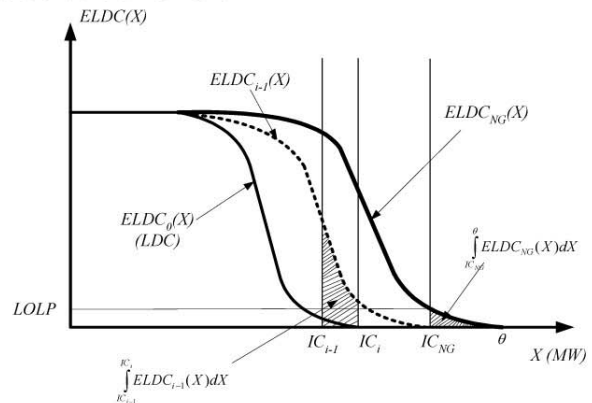


Fig. 3 ELDC obtained by a recursive algorithm for capacity model building

2.2 Deconvolution Process

Deconvolution is the reverse process of convolution. From (1), to find the previous ELDC, with the outage of unit i removed from the ELDC, the outage of unit i can be deconvolved by rearranging (1) as follows,

$$ELDC_{i-1}(X) = \frac{1}{1 - FOR_i} \cdot ELDC_i(X) + \frac{FOR_i}{1 - FOR_i} \cdot ELDC_{i-1}(X - P_{Gi}), \quad (2)$$

Similarly on the ELDC, the outage effect of unit j , which was loaded previously and not necessarily adjacent to unit i can be removed by the following (3). The new ELDC ($ELDC'$) after the effect of unit j , can be computed as,

$$ELDC'_{i-1}(X) = \frac{1}{1 - FOR_i} \cdot ELDC_{i-1}(X) + \frac{FOR_i}{1 - FOR_i} \cdot ELDC'_{i-1}(X - P_{Gj}). \quad (3)$$

2.3 Expected Energy Served and Not Served

The expected energy served by generator i are calculated by,

$$ES_i = (1 - FOR_i) \cdot T \cdot \int_{IC_{i-1}}^{IC_i} ELDC_{i-1}(X) dX, \quad (4)$$

and the total daily operating cost is,

$$ETC = \sum_{i=1}^{NG} FC_i = \sum_{i=1}^{NG} PFC_i \cdot ES_i, \quad (5)$$

The expected energy not served is calculated by,

$$EENS = T \cdot \int_{IC_{NG}}^{\theta} ELDC_{NG}(X) dX, \quad (6)$$

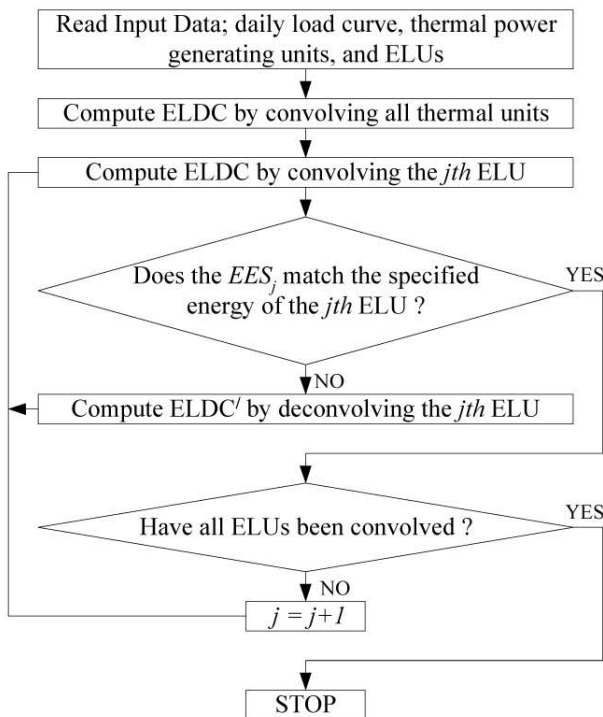


Fig. 4 Computational procedure

where

ES_i = the expected energy served by generator i (MWh),

T = total period under consideration (24 h),

IC_{i-1} = the sum of capacity when the generating system through the $i-1$ th unit is being considered with merit order operation (MW),

IC_i = the sum of capacity when the generating system through the i th unit is being considered with merit order operation (MW),

FC_i = Daily fuel cost of generator i (THB),

PFC_i = Per unit fuel cost of generator i (THB/MWh).

$EENS$ = the expected energy not served (MWh)

IC_{NG} = total installed capacity (MW)

$\theta = X|_{ELDC_{NG}(X)=0}$ = the equivalent system peak load (MW).

The computation of ES_i and $EENS$ are illustrated in Fig. 1. The deconvolution of each LEU is preceded until its EENS matches its daily energy assigned. The computational procedure is shown in Fig. 4.

3. Simulation Results

The test data is obtained from historical data of EGAT [1]. There are 110 power generating units, including 16 hydro plants taken into account in the simulation. The load curve of fiscal year 2001 is used. SPP power plants are dispatched based on the power purchase agreements which are not based on its prices. They are modeled in the load curve based on the power purchase agreement to operate at full capacity from 08.00 a.m. to 08.00 p.m. on weekdays and at 65% of its full load from 8.00 p.m. to 8.00 a.m. on weekday, and whole Saturday and Sunday. IPP and EGAT power plants are operated according to the merit order. The daily load curve of peak day in fiscal year 2001 (23 April 2001) is shown in Fig. 5.

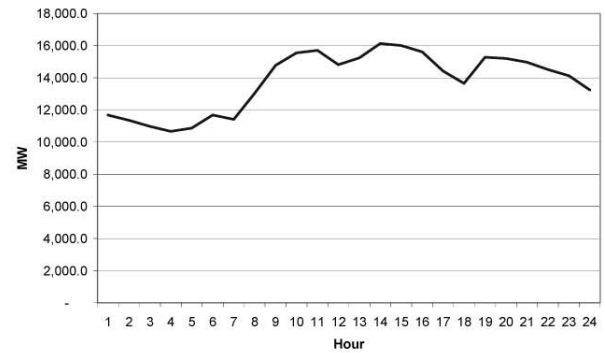


Fig. 5 Daily load curve of Thailand on 23 April 2001

There are two case studies which are;

- Case 1: Hydro power plants are modeled in the load curve by using the equivalent MW from the historical water discharge data without using deconvolution techniques and
- Case 2: Hydro power plants are convolved and deconvolved using the deconvolution technique.

Table 1 The summary results of Thai Power System

Item	Case 1	Case 2
System Peak Excluding SPPs (MW)	17854.3	17854.3
EENS (MWh)	27.56	25.78
LOLP	7.7×10^{-7}	8.2×10^{-9}
LOLH (h)	1.85×10^{-5}	1.9×10^{-7}
Total ES by hydro units (MWh)	22574	22574
ETC (MTHB)	276.51	274.66

The ELDC with and without deconvolution are shown in Fig. 6 and 7, respectively. Table 2 shows the simulation results including LOLP, LOLH, EENS, ETC, and the total ES of hydro generating units of Case 1 and Case 2.

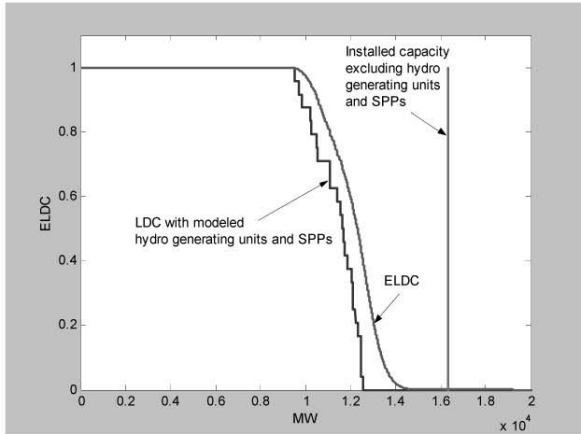


Fig. 6 the results from capacity model building without deconvolution (Case 1)

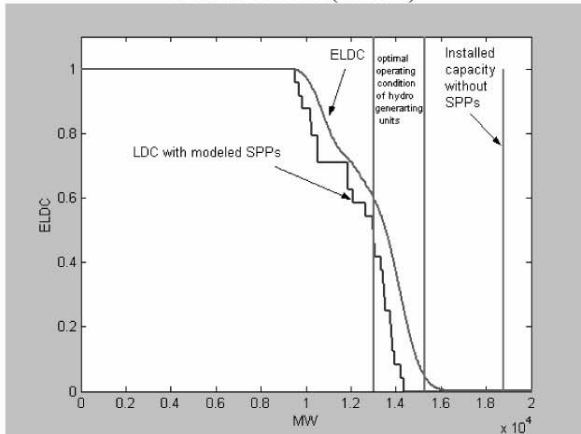


Fig. 7 The result from deconvolution for optimal scheduling of hydro generating units (Case 2)

In this simulation, the LOLP of scheduling with deconvolution is shown to be lower than that of scheduling without deconvolution leading to the lower LOLH and EENS. The optimal condition for hydro generating units scheduling is to operate them in between 13190 MW to 15630 MW of the load curve. With the same EES of hydro generating units, the ETC of the optimal scheduling of using deconvolution is 0.67% lower than that of scheduling without deconvolution.

Despite the small daily saving in percent of the Thai system, the total annual savings in THB could be substantial. This implies that deconvolution can efficiently utilize the specified energy of hydro generating units.

4. Conclusions

The deconvolution technique base optimal scheduling of LEUs in power systems has been investigated. The method can efficiently determine the optimal scheduling of hydro generating units. The developed program is potentially applicable for preliminary scheduling of LEUs before solving the unit commitment problem.

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Appendix

Table A The recursive algorithm for capacity model building

The cumulative probability of outage					
MW on outage	Original LDC	ELDC With Unit 1 FOR	ELDC With Unit 2 FOR	...	ELDC With Unit NG FOR
0	$LDC(0)$	$ELDC_0(0)$	$ELDC_0(0)$...	$ELDC_0(0)$
ST	$LDC(ST)$	$ELDC_1(ST) = (1 - FOR_1 \times ELDC_0(ST)) + FOR_1(ELDC_0(0))$	$ELDC_2(ST) = (1 - FOR_2 \times ELDC_1(ST)) + FOR_2(ELDC_1(0))$...	$ELDC_{NG}(ST) = (1 - FOR_{NG} \times ELDC_{NG-1}(ST)) + FOR_{NG}(ELDC_{NG-1}(0))$
...
P_{C1}	$LDC(P_{C1})$	$ELDC_1(ST) = (1 - FOR_1 \times ELDC_0(P_{C1})) + FOR_1(ELDC_0(0))$	$ELDC_2(ST) = (1 - FOR_2 \times ELDC_1(P_{C1})) + FOR_2(ELDC_1(0))$...	$ELDC_{NG}(P_{C1}) = (1 - FOR_{NG} \times ELDC_{NG-1}(P_{C1})) + FOR_{NG}(ELDC_{NG-1}(0))$
$P_{C1} + ST$	$LDC(P_{C1} + ST)$	$ELDC_1(ST) = (1 - FOR_1 \times ELDC_0(P_{C1} + ST)) + FOR_1(ELDC_0(ST))$	$ELDC_2(ST) = (1 - FOR_2 \times ELDC_1(P_{C1} + ST)) + FOR_2(ELDC_1(0))$...	$ELDC_{NG}(P_{C1} + ST) = (1 - FOR_{NG} \times ELDC_{NG-1}(P_{C1} + ST)) + FOR_{NG}(ELDC_{NG-1}(P_{C1} + ST - P_{CNG}))$
...
P_{C2}	$LDC(P_{C2})$	$ELDC_1(ST) = (1 - FOR_1 \times ELDC_0(P_{C2})) + FOR_1(ELDC_0(P_{C2} - P_{C1}))$	$ELDC_2(ST) = (1 - FOR_2 \times ELDC_1(P_{C2})) + FOR_2(ELDC_1(0))$...	$ELDC_{NG}(P_{C2}) = (1 - FOR_{NG} \times ELDC_{NG-1}(P_{C2})) + FOR_{NG}(ELDC_{NG-1}(P_{C2} - P_{CNG}))$
$P_{C2} + ST$	$LDC(P_{C2} + ST)$	$ELDC_1(ST) = (1 - FOR_1 \times ELDC_0(P_{C2} + ST)) + FOR_1(ELDC_0(P_{C2} + ST - P_{C1}))$	$ELDC_2(ST) = (1 - FOR_2 \times ELDC_1(P_{C2} + ST)) + FOR_2(ELDC_1(ST))$...	$ELDC_{NG}(P_{C2} + ST) = (1 - FOR_{NG} \times ELDC_{NG-1}(P_{C2} + ST)) + FOR_{NG}(ELDC_{NG-1}(P_{C2} + ST - P_{CNG}))$
...