Optimal Scheduling of Hydro Power Generation Using Deconvolution Technique: A Case Study of Thai Power System

Keerati Chayakulkheeree

***Abstract*— *In this paper, the deconvolution technique is applied to determine an optimal daily scheduling of hydro power plants in Thailand. The hydro generating units are model as limited energy units (LEUs) or assigned energy (AE) units. 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. The simulation results including Loss of Load Probability (LOLP), Loss of Load Hour (LOLH), Expected Energy Not Served (EENS), and the Equivalent Total Cost (ETC), introduced in the paper are shown and discussed. With the same EES of hydro generating units, the ETC of the optimal scheduling of using deconvolution is lower than that of scheduling without deconvolution. 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 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.*

***Keywords*— Energy limited unit, capacity model building, equivalent load duration curve, convolution, deconvolution.**

1. INTRODUCTION

In a power generation scheduling, the operating costs of the units can be 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. 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 plants, 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 the MEA, PEA and limited number of direct consumers. Fig. 1 shows the structure of present Thai power system [1]. As of fiscal year 2008, hydro power shares about 10% of total power generation in Thailand. 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 ELUs and it is productive to develop the tool for optimal scheduling of the hydro generating units.

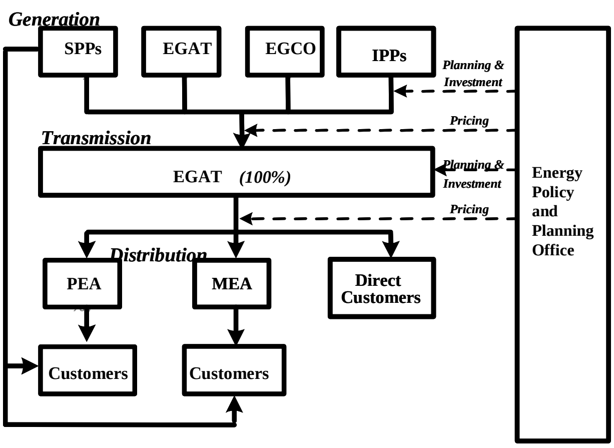

Fig. 1. The structure of present Thai power system.

Many techniques have been proposed to determine

Keerati Chayakulkheeree is with Department of Electrical Engineering, Faculty of Engineering, Sripatum University, 61, Pahonyothin Rd., Senanikom, Jatujak, Bangkok, Thailand, 10900, email: keerati.ch@spu.ac.th.

optimal scheduling of LEUs in power systems. Bloom [2] 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 [3-6]. 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 [7]. Nevertheless, the framework for applying the technique to practical problem has not been fully developed due to its intensive mathematical computation.

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. The results shown that deconvolution technique can dispatch efficiently utilize the specified energy of hydro generating units, leading to lower total fuel cost. The method is potentially applicable for preliminary scheduling of LEUs before solving the unit commitment problem.

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 [8], the cumulative probability of a particular capacity outage state of X MW or the equivalent load duration curve, after a unit generating at PGi MW and force outage rate FORi is considered, is given by,

$$\begin{aligned} ELDC_i(X) = (1 - FOR_i) \cdot ELDC_{i-1}(X) + \\ FOR_i \cdot ELDC_{i-1}(X - P_{Gi}), \end{aligned} \tag{1}$$

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).

The Appendix 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. 2 shows the ELDC after taken into account the units FOR.

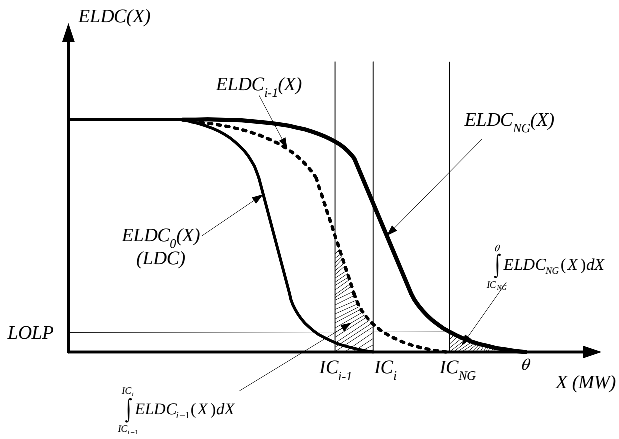

Fig. 2. ELDC obtained by a recursive algorithm for capacity model building.

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* is 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,

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

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)

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

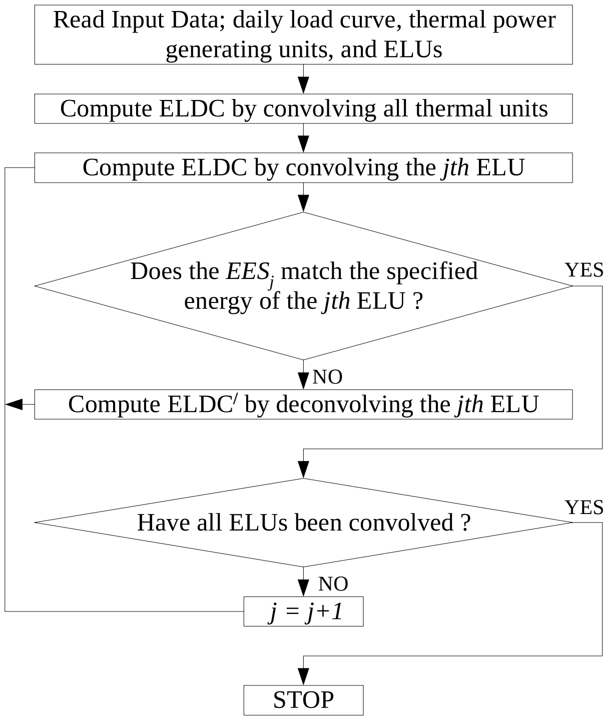

Fig. 3. Computational procedure.

The computation of ESi and EENS is illustrated in Fig. 2. The deconvolution of each LEU is preceded until its EENS matches its daily energy assigned. The computational procedure is shown in Fig. 3.

3. SIMULATION RESULTS

The test data are arbitrarily chosen from historical data of Thailand power system. The data are simplified and unavailable data are chosen from standard values. There are 99 power generating units, including hydro plants taken into account in the simulation. SPP power plants, with their installed capacity of 2092.8 MW, 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 the full capacity from 8.00 p.m. to 8.00 a.m. on weekdays, and whole Saturday and Sunday. IPP and EGAT power plants are operated according to the merit order. The daily load curve of Thailand peak day in 2008, shown in Fig. 4, with the peak of 22568.20 MW, is used in the simulation.

The simulation results are based on comparison of two methods as shown in Case 1 and 2, without and with deconvolution technique, respectively, as follows.

- *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 technique and
- *Case 2*: Hydro power plants are convolved and deconvolved using the deconvolution technique.

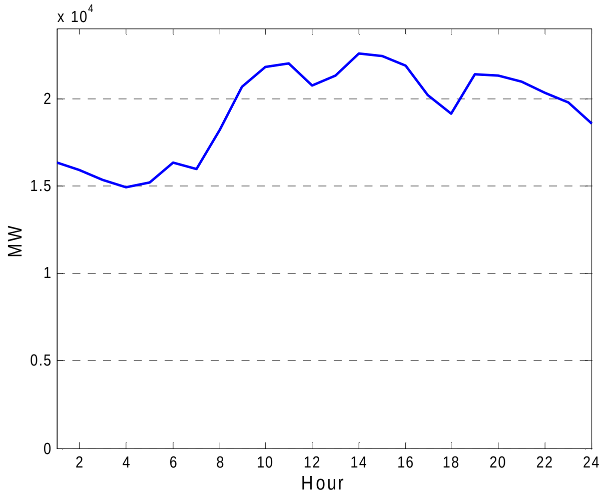

Fig. 4. Daily load curve of Thailand peak day in 2008.

The ELDC with and without deconvolutions are shown in Fig. 5 and 6, respectively. Table 1 shows the simulation results including LOLP, LOLH, EENS, ETC, and the total ES of hydro generating units of Case 1 and Case 2. In Fig. 5., the hydro power plants are modeled in the load curve and installed capacity excluding the hydro power plants and SPP is shown. The daily load curve with hydro power plants loading is shown in Fig. 6. In Fig. 7, the hydro power plants are loading in to the ELDC using deconvolution technique and the installed capacity including hydro power plant but excluding SPP is shown.

Table 1. The summary results

Item	Average Loading for Hydro Unit Case	Case 1 without deconvolution technique	Case 2 with deconvolution technique
System Peak (MW)	22568.20	22568.20	22568.20
EENS (MWh)	1.243×10^{-3}	3.901×10^{-6}	4.555×10^{-5}
LOLP	3.67×10^{-11}	1.23×10^{-13}	1.26×10^{-12}
Total ES by hydro units (MWh)	23674.902	23674.902	23674.902
ETC (MTHB)	496.114	493.577	493.228

In this simulation, the LOLP of scheduling with deconvolution is shown to be higher than that of scheduling without deconvolution leading to the higher LOLH and EENS. However, with the same EES of hydro generating units, the ETC of the optimal scheduling of using deconvolution is lower than that without deconvolution. The optimal condition for hydro generating units scheduling is to operate them in between 1820.51 MW to 2162.88 MW of the load curve as shown in Fig.7. Despite the small daily saving 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.

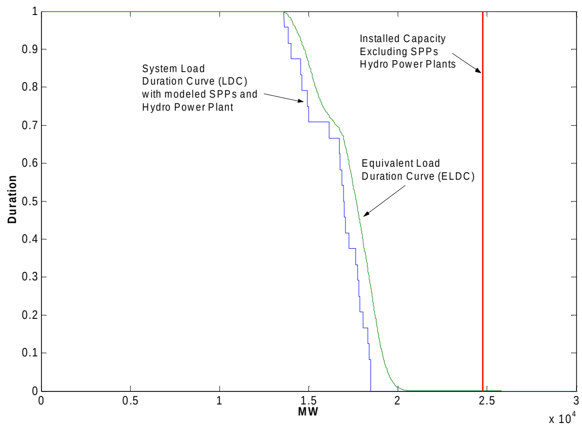

Fig. 5. The results from capacity model building without deconvolution (Case 1).

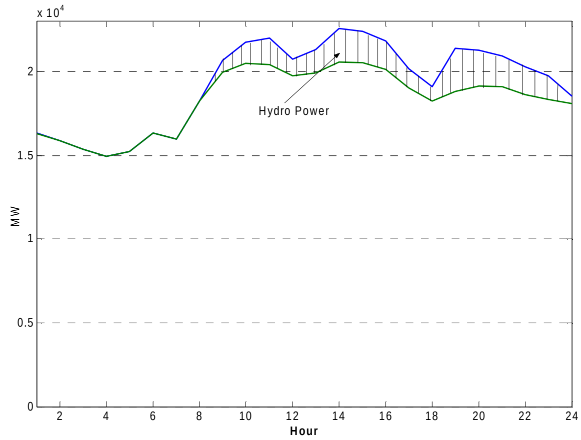

Fig. 6. The daily load curve with historical hydro power plants loading (Case 1).

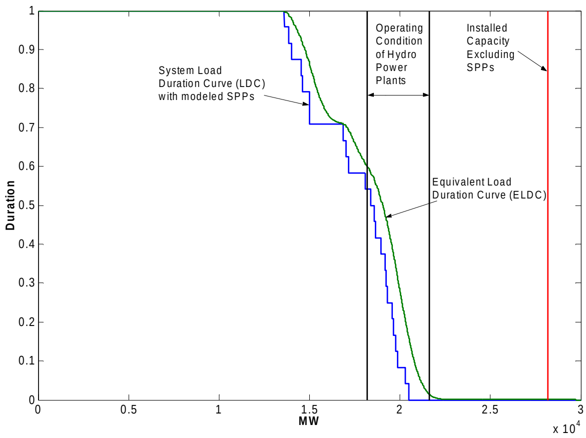

Fig. 7. The result from deconvolution for optimal scheduling of hydro generating units (Case 2).

4. CONCLUSION

The deconvolution technique base optimal scheduling of LEUs in power system 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.

ACKNOWLEDGMENT

This work is supported by The Thailand Research Fund under contract number RDG5150056.

REFERENCES

[1] Electricity Generating Authority of Thailand, 2008. Statistical Report Fiscal Year 2008, Thailand.

[2] J. A. Bloom. 1981. Long-Range Generation Planning with limited energy and storage units: Part 1 and 2, Technical report 486 and 487, School of operating research and industrial engineering, Cornell University.

[3] Rudolf and R. Bayrleithner. 1999. "A genetic algorithm for solving the unit commitment problem of hydro-thermal power system." *IEEE Trans. Power System*, Vol. 14, No. 4, pp. 1460-1468.

[4] Chaa-An Li, R. B. Johnson, A. J. Svoboda, Chung-Li Tseng, and E. Hsu. 1998. "A robust unit commitment algorithm for hydro-thermal optimization." *IEEE Trans. Power Systems*, Vol. 13, No. 3, pp. 1051-1056.

[5] N. J. Redondo and A. J. Conejo. 1999. "Short-term hydro-thermal coordination by Lagrangian relaxation: solution of the dual problem." *IEEE Trans. Power Systems*, Vol. 14, No. 1, pp. 89-95.

[6] Xaiomin Bai and S. M. Shahidehpour. 1996. "Hydro-thermal, scheduling by tabu search and decomposition method." *IEEE Trans Power Systems*, Vol. 11, No. 2, pp. 968-974.

[7] S. Malik and B. J. Cory. 1996. "Efficient algorithm to optimise the energy generation by pumped storage units in probabilistic production costing." *IEE Proc.-Gener. Transm. Distrib.*, pp. 546-552.

[8] R. Billinton and R. N. Allan. 1996. Reliability Evaluation of Power Systems. New York, NY: Plenum Press.

APPENDIX

The reclusive 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	$LDC(ST)$	$ELDC_1(ST)=(1-FOR_1)(ELDC_0(ST)) + FOR_1(ELDC_0(0))$	$ELDC_2(ST)=(1-FOR_2)(ELDC_1(ST)) + FOR_2(ELDC_1(0))$	...	$ELDC_{NG}(ST)=(1-FOR_{NG})(ELDC_{NG-1}(ST)) + FOR_{NG}(ELDC_{NG-1}(0))$
⋮	⋮	⋮	⋮	...	⋮
P_{G1}	$LDC(P_{G1})$	$ELDC_1(ST)=(1-FOR_1)(ELDC_0(P_{G1})) + FOR_1(ELDC_0(0))$	$ELDC_2(ST)=(1-FOR_2)(ELDC_1(P_{G1})) + FOR_2(ELDC_1(0))$	...	$ELDC_{NG}(P_{G1})=(1-FOR_{NG})(ELDC_{NG-1}(P_{G1})) + FOR_{NG}(ELDC_{NG-1}(P_{G1}-P_{GNG}))$
$P_{G1}+ST$	$LDC(P_{G1}+ST)$	$ELDC_1(ST)=(1-FOR_1)(ELDC_0(P_{G1}+ST)) + FOR_1(ELDC_0(ST))$	$ELDC_2(ST)=(1-FOR_2)(ELDC_1(P_{G1}+ST)) + FOR_2(ELDC_1(0))$	...	$ELDC_{NG}(P_{G1}+ST)=(1-FOR_{NG})(ELDC_{NG-1}(P_{G1}+ST)) + FOR_{NG}(ELDC_{NG-1}(P_{G1}+ST-P_{GNG}))$
⋮	⋮	⋮	⋮	...	⋮
P_{G2}	$LDC(P_{G2})$	$ELDC_1(ST)=(1-FOR_1)(ELDC_0(P_{G2})) + FOR_1(ELDC_0(P_{G2}-P_{G1}))$	$ELDC_2(ST)=(1-FOR_2)(ELDC_1(P_{G2})) + FOR_2(ELDC_1(0))$	...	$ELDC_{NG}(P_{G2})=(1-FOR_{NG})(ELDC_{NG-1}(P_{G2})) + FOR_{NG}(ELDC_{NG-1}(P_{G2}-P_{GNG}))$
$P_{G2}+ST$	$LDC(P_{G2}+ST)$	$ELDC_1(ST)=(1-FOR_1)(ELDC_0(P_{G2}+ST)) + FOR_1(ELDC_0(P_{G2}+ST-P_{G1}))$	$ELDC_2(ST)=(1-FOR_2)(ELDC_1(P_{G2}+ST)) + FOR_2(ELDC_1(ST))$	...	$ELDC_{NG}(P_{G2}+ST)=(1-FOR_{NG})(ELDC_{NG-1}(P_{G2}+ST)) + FOR_{NG}(ELDC_{NG-1}(P_{G2}+ST-P_{GNG}))$
⋮	⋮	⋮	⋮	...	⋮