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RESEARCH ARTICLE

Enhancing Generation Expansion Planning With Integration of Variable Renewable Energy and Full-Year Hourly Multiple Load Levels Balance Constraints

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ABSTRACT This paper proposes a method for generation expansion planning that incorporates full-year hourly multiple load levels balance constraints, providing sufficient flexibility to address load fluctuations and intermittency associated with variable renewable energy sources. Typically, ensuring that the generation system possesses enough flexibility to manage this intermittency involves considering the operational characteristics of generators within unit commitment constraints. However, to mitigate the substantial computational burden caused by the number and type of variables, various approximation techniques are often employed. Unfortunately, these techniques can introduce unrealistic elements into the problem. Instead of considering the operational characteristics of generators, this approach classifies the system's demand into three levels: base load, intermediate load, and peak load, using the proposed load classification method. The multiple load-level balance constraints are then applied to ensure that the capacity of generation units in each level is sufficient to meet their corresponding demand, with particular emphasis on matching fast-response generation units and their corresponding demand. The resulting generation expansion plan can be obtained with significantly reduced computational effort. The proposed load classification method and generation expansion planning approach have been tested using the latest power development plan of Thailand. Compared to another method that is not taken flexibility into account, 5 Gigawatts of fast-response generation capacity are selected instead of base load generation units. With the improved computational time achieved by the proposed generation expansion planning method, it can account for input data uncertainty by solving multiple generation expansion planning problems with varying input data and distinct individual probabilities.

INDEX TERMS Power generation planning, power generation reliability, generation expansion planning, renewable energy.

NOMENCLATURE

A. ACRONYMS

BESS	Battery energy storage system.
CCGT	Combined cycle gas turbine.
COPT	Capacity outage probability table.
DR	Demand response.
DSM	Demand side management.
ED	Economic dispatch.
ELU	Energy limited unit.
ESS	Energy storage system.
EV	Electric vehicle.
FOR	Forced outage rate.
GEP	Generation expansion planning.
GT	Gas turbine.
GW	Gigawatt.
GWh	Gigawatt-hour.
HRL	Hourly load curve.
IEA	International Energy Agency.
LCOE	Levelized cost of electricity.

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MILP	Mixed integer linear programming.
$MTCO_2$	Million metric tons of carbon dioxide.
MTU	Must-take unit.
MW	Megawatt.
MWh	Megawatt-hour.
NG	Natural gas.
NREL	National Renewable Energy Laboratory.
OCGT	Open-cycle gas turbine.
O&M	Operation and maintenance.
PDF	Probability density function.
PF	Plant factor.
PHS	Pumped hydroelectricity storage.
THB	Thai Baht.
UC	Unit commitment.
USD	United State Dollar.
V2G	Vehicle-to-grid.
VRES	Variable renewable energy sources.

B. INDICES

d	Duration of load duration curve.
f	Fuel type of the generation unit.
g	Type of generation unit.
h	Hour in the considered month.
j	Generation unit or ESS unit in each type.
k	Type of candidate generation unit.
l	Load level, given that; $l = 1$ is assigned to peak load, $l = 2$ is assigned to intermediate load, and $l = 3$ is assigned to base load.
m	Month in the planning horizon.
s	Type of energy storage unit.
t	Year in the service life of the candidate generation unit.
y	Year in the planning horizon.

C. PARAMETERS

$\mathrm{Cap}_{f,l,g,j,y,m}$	Maximum output capacity of generation unit fuel f load level l type g unit j in month m of year y (MW).
$\mathrm{Cap}_{f,l,k,t}$	Capacity of the candidate generation fuel f load level l type k in service for t years (MW).
cycle	The number of cycle that ESS unit fully charged and fully discharged per day (-).
day_m	Number of days in month m (day).
DT_m^l	Durations that the generation units of level l need to be operated in month m (hr).
$e_{f,l,g,j,y}$	Operating cost of generation unit fuel f load level l type g unit j in year y (THB/MWh).
e_X^l	Penalty of using slack generation variables; $e_X^1 = 1.2 \times 10^6$ THB/MWh $e_X^2 = 1.1 \times 10^6$ THB/MWh $e_X^3 = 1.0 \times 10^6$ THB/MWh.
e_Y	Operating cost of slack ESS variable, equal to 10^{-3} THB/MWh.
$E_{f,l,k,t}$	Expected generated electricity of candidate generation units.
$\mathrm{EE}_{f,l,g,j,m}$	Expected energy output of generation unit fuel f load level l type g unit j in month m (MWh).
EF_f	Emission factor of fuel f (kgCO2/Btu).
$\mathrm{En}_{s,j,h}$	Stored energy in ESS unit type s unit j in hour h (MWh).
$\mathrm{En}_{s,j,y,m}^{max}$	Energy capacity of ESS unit type s unit j in month m of year y (MWh).
$\mathrm{ePF}_{f,l,k}$	Expected plant factor of candidate generation unit fuel f load level l type k (%).
ePF_l	Expected plant factor of generation units in level l (%).
$\mathrm{FC}_{f,y}$	Fuel cost of fuel f in year y (USD/Btu).
$\mathrm{FOM}_{f,l,g,j}$	Fixed O&M cost of generation unit fuel f load level l type g unit j (THB/MW/year).
$\mathrm{FOM}_{f,l,k}$	Fixed O&M cost of candidate generation unit fuel f load level l type k (THB/MW/year).
$\mathrm{FOR}_{f,l,g,j}$	Forced outage rate of generation unit fuel f load level l type g unit j (-).
FX_y	Exchange rate in year y (THB/USD).
$G_{f,l,g,h}$	Standard generation profile of generation unit fuel f load level l type g in hour h (%).
H_m	The number of hours in month m (hours).
$\mathrm{HR}_{f,l,g,j}$	Heat rate of generation unit fuel f load level l type g unit j (Btu/MWh).
$\mathrm{HR}_{f,l,k}$	Heat rate of candidate generation unit fuel f load level l type k (Btu/MWh).
$\mathrm{Hw}_{s,j}$	Number of working hours per month for ESS type s unit j (hours).
$I_{f,l,k}^0$	Investment cost per installed capacity of candidate generation fuel f load level l type k (THB/MW).
L_h	Net load of hour h (MW).
L_h^1	Peak load of hour h (MW).
L_h^2	Intermediate load of hour h (MW).
L_h^3	Base load of hour h (MW).
L^B	Total demand in base load (MW).
L^I	Total demand in intermediate load (MW).
L^P	Total demand in peak load (MW).
$\mathrm{LCOE}_{f,l,k}$	Levelized cost of electricity of candidate generation unit fuel f load level l type k (THB/kWh).
$\mathrm{LDC}_{f,l,g,j,d}^D$	Load that occurs for d hours in the original LDC before modified by generation unit fuel f load level l type g unit j (MW).
$\mathrm{LDC}'^D_{f,l,g,j,d}$	Load that occurs for d hours in the second state modified LDC, modified by generation unit fuel f load level l type g unit j (MW).

$\mathrm{LDC}''^{D}_{f,l,g,j,d}$ Load that occurs for d hours in the final LDC, modified by generation unit fuel f load level l type g unit j (MW).

$\mathrm{LDC}^{e}_{s,j,d}$ Load that occurs for d hours in the original LDC before modified by ESS unit type s unit j (MW).

$\mathrm{LDC}'^{e}_{s,j,d}$ Load that occurs for d hours in the final LDC, modified by ESS unit type s unit j (MW).

LDC^{T}_{d} Load that occurs for d hours in LDC without MTU generation (MW).

LDC'^{T}_{d} Load that occurs for d hours in LDC without MTU and ELU generation (MW).

$\mathrm{LDC}^{R}_{f,l,g,j,d}$ Load that occurs for d hours in the original LDC before modified by generation unit fuel f load level l type g unit j (MW).

$\mathrm{LDC}'^{R}_{f,l,g,j,d}$ Load that occurs for d hours in the second state modified LDC, modified by generation unit fuel f load level l type g unit j (MW).

$\mathrm{LDC}''^{R}_{f,l,g,j,d}$ Load that occurs for d hours in the final LDC, modified by generation unit fuel f load level l type g unit j (MW).

$N_{f,l,g,y,m}$ The number of existing generation units of fuel f load level l type g in month m of year y (-).

$N_{s,y,m}$ The number of existing ESS units of type s in month m of year y (-).

$P^{\max}_{s,j}$ Power capacity of ESS unit type s unit j (MW).

$P^{D\max}_{f,l,g,j}$ Maximum power output of generation unit fuel f load level l type g unit j (MW).

$P^{D\min}_{f,l,g,j}$ Minimum power output of generation unit fuel f load level l type g unit j (MW).

$\mathrm{Ps}^{\mathrm{ch}}_{s,j}$ Maximum system power input (charge state) of ESS unit type s unit j (MW).

$\mathrm{Ps}^{\mathrm{dch}}_{s,j}$ Maximum system power output (discharge state) of ESS unit type s unit j (MW).

r Discount rate (-).

$\mathrm{SL}_{f,l,k}$ Service life of the candidate generation unit fuel f load level l type k (year).

SOC^{0} Initial state of charge of ESS (%).

$\mathrm{SOC}^{\max}_{s,j}$ Maximum state-of-charge of ESS unit type s unit j (%).

$\mathrm{SOC}^{\min}_{s,j}$ Minimum state-of-charge of ESS unit type s unit j (%).

$\mathrm{VOM}_{f,l,g,j}$ Variable O&M cost of generation unit fuel f load level l type g unit j (THB/MWh).

$\mathrm{VOM}_{f,l,k}$ Variable O&M cost of candidate generation unit fuel f load level l type k (THB/MWh).

$\delta_{f,y,m}$ Maximum fuel ratio criteria of fuel f in month m of year y (%).

$\varepsilon_{y,m}$ Maximum carbon dioxide emission criteria in month m of year y ($\mathrm{kgCO_2}$).

$\eta^{\mathrm{ch}}_{s,j}$ Charging efficiency of ESS unit type s unit j (%).

$\eta^{\mathrm{dch}}_{s,j}$ Discharging efficiency of ESS unit type s unit j (%).

D. VARIABLES

$P^{D}_{f,l,g,j,h}$ Power dispatched in economic dispatch model for hour h of generation unit fuel f load level l type g unit j (MW).

$P^{R}_{f,l,g,j,h}$ Power dispatched in reliability model for hour h of generation unit fuel f load level l type g unit j (MW).

$P^{\mathrm{ch}}_{s,j,h}$ Power absorbed by ESS type s unit j in hour h (MW).

$P^{\mathrm{dch}}_{s,j,h}$ Power supplied by ESS type s unit j in hour h (MW).

X^{l}_{h} Slack generation variable in hour h of level l.

Y_{h} Slack ESS variable in hour h.

I. INTRODUCTION

A. MOTIVATION

At present, many countries are planning to increase their share of renewable energy for power generation driven by concerns about the global energy crisis and climate change [1]. According to the International Energy Agency (IEA), electricity generated from variable renewable energy sources (VRES), such as wind and solar power, is projected to contribute to 80% of the global power generation increase over the next five years [1]. Although these VRES are greenhouse gas (GHG) free, their variability and intermittency pose significant short-term operational challenges for the generation system in balancing supply and demand [2], [3]. This intermittency can occasionally lead to a reduction in the reliability of the generation system [4]. To guarantee that the generation system can overcome this challenge, enhancing the operational flexibility of the power system is essential [5], and an optimal allocation of flexible sources becomes necessary [6]. It makes generation expansion planning (GEP) in the current situation more challenging.

The objective function of conventional GEP typically revolves around total cost minimization [7], [8]. When employing this objective function without additional active constraints, candidate generation units with the lowest operating cost or levelized cost of electricity (LCOE) will be selected for generation expansion. These selected units commonly include a thermal, nuclear power plant, or combined cycle gas turbine (CCGT) units, depending on fuel availability and other system-specific constraints. Despite their lower generation cost, they require continuous operation at or close to their rated output, to generate electricity at the design operating cost [9]. However, achieving such steady operation becomes challenging with a high level of VRES due to the variability and intermittency of VRES [9]. Therefore, in practice, the operating cost of these units might not be as low as initially designed. Furthermore, due to their low ramp rate and long start-up time, these selected units might not be able to maintain the balance of supply and demand in power generation [10]. This imbalance could occasionally lead to a partial blackout, compromising the stability and reliability of the power system. As a result, it is necessary to introduce additional constraints in GEP to ensure that the generation system has sufficient flexibility to effectively cope with VRES [9].

B. LITERATURE REVIEW

The generation expansion planning to accommodate VRES has received significant attention in recent years [11]. One approach to ensuring that the generation system possesses sufficient flexibility to balance supply and demand involves considering the operational characteristics of generators, specifically, minimum up/down times and ramping limits, within unit commitment (UC) constraints. Ideally, for a comprehensive representation of operational flexibility, the operational model should be integrated into a UC problem, capturing the chronological net load over a multi-year planning horizon [12] at the level of individual power plants [9]. Many researchers have concluded that incorporating these UC constraints into the generation expansion decision-making process necessitates modeling the problem using mixed integer linear programming (MILP) [12], [13]. In this context, the integer variables denote generation expansion decisions and UC decisions. Additionally, the application of linear approximations is also essential to lessen computational complexities.

Although linearly simplified, the computational complexity of the GEP with UC constraints remains a significant challenge due to the vase number of variables that need consideration [14], [15]. Hence, various types of approximation techniques have been introduced to reduce the computational load, particularly when dealing with models tested on actual power systems comprising hundreds of generation units. These approximations include clustering generation unit to reduce the number of variables [14], [16], [17], [18], employing representative day [9], [13], [18], [19], [20], [21], [22], [23], [24], or simplifying the operational model [12], [14]. Another method for mitigating this complexity involves considering only the target year [25] at the end of the planning horizon, as applied in [9], [12], [14], [16], and [23]. Alternatively, further reduction in the number of variables can be achieved by breaking down the problem into smaller blocks of overlapping days that are iteratively processed throughout the year [26].

Although these approximations enhance the computational efficiency of GEP with UC constraints, they can introduce unrealistic elements to the problem by overlooking several essential aspects of long-term GEP. For instance, in the generation unit clustering method, which aimed to efficiently reduce the number of variables, the clustered groups of generation units are often minimized, typically based on technology. However, this approach disregards various individual characteristics of generation units, such as technical and financial factors [19]. The representative day method encounters limitations in accurately selecting periods that can well represent VRES generation patterns [27] and future load profiles. Additionally, choosing only a few days within a year may lead to overly optimistic scenarios for renewable energy penetration [14], as it overlooks the hourly and seasonal intermittency of renewable energy sources and fails to account for seasonal or holiday load variations. Moreover, certain annual constraints might be omitted due to the absence of annual energy demand information, such as constraints related to annual fuel mix or carbon dioxide emissions limitations [15]. Lastly, the use of a representative day lacks sufficient detail, especially when incorporating an Energy Storage System (ESS) into the generation system, as ESS might not necessarity need to be fully charged and discharged within a day [15]. In the target-year model, which focuses only on the final year of the planning horizon, crucial information regarding the timing of new generator construction remains unaddressed [25].

Given the computational burden posed by UC problems and their oversimplified approximations, several scholars have explored alternative approaches by focusing on ramping capability – the ability of a generating resource to adjust its output rate [8], [28]. Instead of addressing the entire UC problem, these researchers have proposed power system planning with specific constraints to ensure that the generation system's ramping rates, both upward and downward, exceed that of the demand. For example, Hu et al. [29] focuses only on ramping limit in his constraints to address flexibility. Li et al. [30] proposed a coordinated generation and transmission expansion planning that considers ramping requirements to tackle the challenges posed by the rapid growth of wind power generation. Dhaliwal et al. [31] proposed a GEP incorporating constraints to balance upward and downward ramping of supply and demand. Moradi-Sepahvand and Amraee [32] proposed an integrated expansion planning approach incorporating constraints related to flexible ramp spinning reserve requirements. Xu et al. [33] developed a two-layer GEP model, featuring a flexible supply and demand balance mechanism and a flexibility check index.

The flexibility of a generation system can be enhanced not only by the supply side but also through the demand side, such as energy storage systems (ESS) [34]. ESS is regards as one of the ideal solutions for mitigating variability and intermittency [35], [36] while maximizing the benefits of VRES [37]. Notable categories of ESS include battery energy storage systems (BESS), vehicle-to-grid (V2G), and pumped hydroelectric storage (PHS) [35]. These systems are efficient [38] and exhibit very high ramping rates compared to other power generation technologies. Thus, ESSs are considered in many proposed GEP models with VRES penetration. For instance, Tejada-Arango et al. [23] proposed a GEP with UC considering ESS as an option to enhance flexibility. Opathella et al. [39], Moradi-Sepahvand and Amraee [32], and Rawa et al. [38] introduced integrated expansion planning models to optimize BESS expansion. Gomez-Villarreal et al. [35] explored the production of hydrogen from electrolyzers as another form of ESS in a GEP. Pombo [40] proposed a generation and storage expansion planning to assess the 100% renewable penetration target. ESS is also considered in models proposed by Dai et al. [34] and Choubineh et al. [24].

In the operation of a generation system, the power system's demand is typically classified into three levels: base load, intermediate load, and peak load [31], [41]. These load levels are typically met by three groups of generation units, each with characteristics that align with the behavior of the corresponding load level. For instance, base load units, such as thermal or nuclear power plants [9] usually have the lowest operating cost and need to be operated continuously at or near their rated output [42]. Intermediate load units, like combined cycle power plants, are positioned between peaking units and base load units. In some cases, intermediate load units might be grouped with peak load units or even base load units, depending on the availability of the fuel used in the generation system. Peaking units, such as hydro or gas turbine power plants, or energy storage systems (ESSs), possess high ramp rates and can be rapidly started or stopped multiple times a day; they are utilized to supply power during peak load periods. Due to the characteristics of peaking units, they offer flexibility to counteract the intermittency of VRES.

Several methods have been proposed for categorizing the demand of each load level, extensively employed across various applications to optimize electricity generation. For instance, Salimi-Beni et al. [42] used a K-means clustering method to classify these demands, serving operational and planning purposes. Nuchprayoon [43] also employed K-means clustering to classify load duration curve into five groups. Guo et al. [44] classified daily demand based on specific periods in a day when certain levels of demand occur, creating a representative load curve for each period used in their case study. Pereira [45] determined these demands through quartile ranges and use this information for designing tariffs. Pereira and Marques [46] further improved the previous method by classifying daily demand by both level and period in a day. This information is used to assist in designing demand-side management (DSM) policies to achieve a flexible smoothed daily demand curve. Although the classification results from these methods are used for operational applications, none of the parameters related to the characteristics of generation system are considered in the classification.

C. CONTRIBUTION OF THIS PAPER

This paper proposes a generation expansion planning (GEP) approach that accommodates VRES. Instead of considering operational characteristics such as generators' minimum up/down times and ramping limits in UC constraints, it employs multiple load levels balance constraints. These constraints ensure that the capacity of generation units in each level is sufficient to meet their corresponding rapid changes in demand due to VRES, with a particular focus on balancing fast-response generation units and their corresponding demand. The methodology for GEP used in this paper is a linear programming model, as proposed in [15] and [47], which approximates the dynamic programming of GEP to a sequence of UC problems. The UC problem is then solved using the priority list method. Hence, with the linear cost assumption for long-term planning, the UC problems are reduced to multiple economic dispatch (ED) problems. This model enables separation of the decision-making process for constructing new power plants and the optimization model for the UC, aiming to eliminate integer variables. Such separation reduces the computational load of the model while retaining essential aspects of long-term planning with VRES, including a multi-year planning horizon, individual unit characteristics, full-year hourly power balance constraints, and the hourly charge-discharge pattern of energy storage systems. Furthermore, this approach allows the calculation and consideration of non-linear indices, such as the loss of load expectation (LOLE) during the decision-making process. In the optimization model for the UC, the balance of multiple load levels is considered. The demands of these load levels are determined using an alternative load classification criterion, which will be discussed in this paper. Unlike deterministic or statistical methods that disregard parameters relating to the characteristics of the generation system, this method is systematic and based on a practical concept that considers the model of generation units' characteristics.

Main contributions of this paper are:

1. Development of a linear GEP model that can simultaneously account for flexibility requirements and other non-linear constraints without any approximation.
2. Development of a load classification method to determine the demand at each load level, which will be used in full-year hourly multiple load levels balance constraints in the GEP.

The proposed load classification and GEP methods are tested with the latest power development plan of Thailand [48]. With the fast computational time obtained from the GEP technique proposed in [15] and [47], the proposed approach can account for input data uncertainty by solving multiple GEP problems with varying input data and distinct individual probabilities.

The rest of this paper is organized as follows: Section II presents the methodology for the alternative load classification. Section III provides a summary of the methodology for generation expansion planning with full-year hourly multiple load level balance constraints. Section IV describes the test system based on Thailand's Power Development Plan 2018 revision 1. Section V discusses impacts of the VRES on the generation expansion plan. Finally, conclusions and directions for the future work are presented in Section VI.

TABLE 1. Generation unit classification.

Load level	Generation type
peak load	VRES, biofuel, waste-to-energy, hydro, DR, gas turbine, gas engine, BESS, PHS
intermediate load	combined cycle
base load	thermal (nuclear, coal-fired)

II. LOAD CLASSIFICATION

The objective of this load classification is to classify load demand into levels. Then, the demand in each level will be served by generation units with characteristics corresponding to that load level. The load classification concept should be systematic; Moreover, it should be linked to the generation units' characteristics. Hence, the model for generation units will be taken into consideration in this load classification. In this section, first, generation types matched with corresponding loads are classified. Then the models for economic dispatch and reliability evaluation of each generation group will be introduced. Lastly, the load classification will be proposed.

A. GENERATION UNIT CLASSIFICATION

The generation types considered in this paper are classified into three groups to match three levels of load demand, as shown in Table 1. Additionally, in this paper, demand response (DR) is also considered as one of the generation types to serve peak demand.

B. GENERATION UNIT MODELING

In this paper, generation types are classified into four groups. The models of these generation units are introduced in this subsection. These models were initially introduced in [15] as an economic dispatch model and were further improved in [47] by incorporating a reliability evaluation model. In this paper, these models are slightly modified and are revisited for more clarity. These models will be used in the proposed load classification and also in the optimization model which will be described in the next sections.

1) MUST-TAKE UNIT

A must-take unit (MTU) is a unit that has a scheduled operation plan, such as a solar PV unit that can supply power depending on solar irradiance, or a unit with a firm contract and pre-specified operation plan. This operation plan can vary depending on the time of day or season. Normally, these units are a must-take power plants which are generation units that the system operator must purchase all of their generated electricity. As a result, they are dispatched according to their operation plan without any restriction. This generation unit will be modelled with a standard hourly generation profile as described in [47]. The model used in the UC for must-take unit is defined in (1) as the product of the standard generation profile and maximum output capacity during the considering period. The model used in the reliability evaluation incorporates the forced outage rate (FOR) as shown in (2).

$$P^{D}_{f,l,g,j,h} = G_{f,l,g,h} \times \mathrm{Cap}_{f,l,g,j,y,m} \tag{1}$$

$$P^{R}_{f,l,g,j,h} = G_{f,l,g,h} \times \mathrm{Cap}_{f,l,g,j,y,m} \times \left(1-\mathrm{FOR}_{f,l,g,j}\right) \tag{2}$$

Generation types in this group consist of VRES such as solar, wind, small hydro, geothermal, along with biofuel and waste-to-energy. All electricity generated from these VRES must be procured to reduce reliance on fossil fuel-based electricity generation. The standard hourly generation profiles of a 1-MW generation unit of each type or fuel can be found in [49]. If power degradation, such as solar PV degradation [50], is considered, $\mathrm{Cap}_{f,l,g,j,y,m}$ should be adjusted accordingly.

2) ENERGY LIMITED UNIT

An energy limited unit (ELU) is a generation unit that typically has low operating cost but has limited resources or limited fuel for electricity generation. Hydroelectric power plants and demand response fall into this category. It cannot be continuously operated at its rated output throughout the considered period due to the exhaustion of its resources. With this limitation, these units are usually operated only in peak load period to reduce the requirement from more expensive peaking units. In this paper, the UC model of the energy limited unit is modelled based on the "peak-shaving" technique described in [51]. This peak-shaving technique involves two stages of load duration curve (LDC) modification as described in [47]. The power output in the UC model of this generation type is defined by the difference between the net hourly load curve (HRL) before and after peak-shaving. These HRLs are obtained by re-sorting the LDC before and after peak shaving processes. The LDC after peak shaving can be calculated using the two-stage technique shown in (3) and (4), respectively. For the reliability model, the FOR is incorporated as shown in (5) and (6). The resulting LDC from (6) will be used in the LOLE calculation afterward. For hydroelectric power plants, since their maximum output capacity depends on the storage level of their reservoir, the value of $\mathrm{Cap}_{f,l,g,j,y,m}$ might be less than or equal to the installed capacity of the power plant, depending on the month or season of the considered period.

$$\mathrm{LDC}'^{D}_{f,l,g,j,d} = \mathrm{LDC}^{D}_{f,l,g,j,d} - \mathrm{Cap}_{f,l,g,j,y,m} \tag{3}$$

$$\mathrm{LDC}''^{D}_{f,l,g,j,d} = \begin{cases} \mathrm{LDC}'^{D}_{f,l,g,j,d}, & \sum_{h=0}^{H_m} \mathrm{LDC}'^{D}_{f,l,gj,d} < \mathrm{EE}_{f,l,g,j,m} \\ \mathrm{LDC}^{D}_{f,l,g,j,d}, & \sum_{h=0}^{H_m} \mathrm{LDC}'^{D}_{f,l,g,j,d} \geq \mathrm{EE}_{f,l,g,j,m} \end{cases} \tag{4}$$

$$\mathrm{LDC}'^{R}_{f,l,g,j,d} = \mathrm{LDC}^{R}_{f,l,g,j,d} - \mathrm{Cap}_{f,l,g,j,y,m} \times \left(1-\mathrm{FOR}_{f,l,g,j}\right) \tag{5}$$

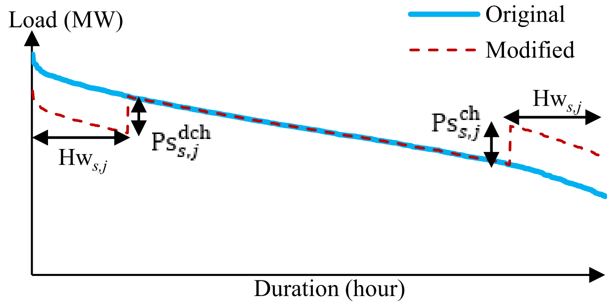

FIGURE 1. **LDC modification process by ESS.**

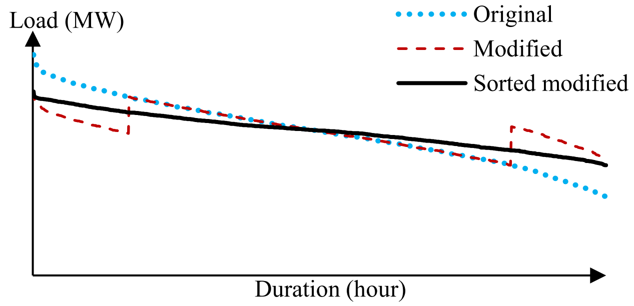

FIGURE 2. **Comparison between original and modified LDC by ESS.**

$$\mathrm{LDC}''^{R}_{f,l,g,j,d} = \begin{cases} \mathrm{LDC}'^{R}_{f,l,g,j,d}, & \sum_{h=0}^{H_m} \mathrm{LDC}'^{R}_{f,l,g,j,d} < \mathrm{EE}_{f,l,g,j,m} \\ \mathrm{LDC}^{R}_{f,l,g,j,d}, & \sum_{h=0}^{H_m} \mathrm{LDC}'^{R}_{f,l,g,j,d} \geq \mathrm{EE}_{f,l,g,j,m} \end{cases} \tag{6}$$

3) DISPATCHABLE ENERGY STORAGE SYSTEM UNIT

This type of ESS is a unit directly controllable by the system operator. It can be charged to store electricity from the grid and discharged to supply the stored electricity back to the grid. In this paper, the power output from this unit is determined by the linear programming model for the UC problems, which will be discussed in the next section. For the reliability model, the potential capacity of each ESS unit along with its FOR is used to modify the LDC$''$ which is used for reliability evaluation ($\mathrm{LDC}''^{R}_{f,l,g,j,d}$) by reducing energy consumption during the peak periods and increasing energy consumption during the off-peak periods. Assuming that ESS units are operated at least for 1 cycle per day, parameters of ESSs, as specified in (7) to (10) need to be calculated and are then applied to adjust the load duration curve. The modification process can be formulated as shown in (11). The result of this modification is illustrated in Fig. 1. If capacity degradation of ESS is considered, the parameter $\mathrm{En}^{max}_{s,j,y,m}$ should be adjusted accordingly.

$$\forall s : \text{cycle} = 1 \times \text{day}_m \tag{7}$$

$$\mathrm{Hw}_{s,j} = \text{cycle} \times \frac{\mathrm{En}^{\max}_{s,j,y,m}}{P^{\max}_{s,j}} \tag{8}$$

$$\mathrm{Ps}^{\mathrm{dch}}_{s,j} = P^{\max}_{s,j} \times \left(1 - \mathrm{FOR}_{s,j}\right) \times \eta^{\mathrm{dch}}_{s,j} \tag{9}$$

$$\mathrm{Ps}^{\mathrm{ch}}_{s,j} = \frac{P^{\max}_{s,j} \times \left(1 - \mathrm{FOR}_{s,j}\right)}{\eta^{\mathrm{ch}}_{s,j}} \tag{10}$$

$$\mathrm{LDC}'^{e}_{s,j,d} = \begin{cases} \mathrm{LDC}^{e}_{s,j,d} - \mathrm{Ps}^{\mathrm{dch}}_{s,j}, & d \leq \mathrm{Hw}_{s,j} \\ \mathrm{LDC}^{e}_{s,j,d}, & \mathrm{Hw}_{s,j} < d \leq H_m - \mathrm{Hw}_{s,j} \\ \mathrm{LDC}^{e}_{s,j,d} + \mathrm{Ps}^{\mathrm{ch}}_{s,j}, & d < H_m - \mathrm{Hw}_{s,j} \end{cases} \tag{11}$$

Then, the modified LDC obtained from (11) will be sorted once again as demonstrated in Fig. 2. And it will be used in the LOLE calculation. In this paper, ESS types in this group consists of PHS and BESS.

4) DISPATCHABLE GENERATION UNIT

This type of unit is a large-scale generation unit that can be directly controlled by the system operator. Normally, it is a generation unit using conventional fuels such as coal, fuel oil, diesel, natural gas, and also nuclear fuel. In this study, it is assumed that the fuel supply for the generation unit in this group is always available and unlimited. Therefore, it can be dispatched as needed. The generation output of this group will be determined from the linear programming model for UC that will be described in the next section, along with that of the ESS unit. The reliability model of this group can be represented by the Capacity Outage Probability Table (COPT) created from the installed capacity and FOR of all generation units as described in [52].

C. LOAD CLASSIFICATION

In this subsection, firstly, load classification methodologies used in other papers are summarized. Then, the load classification concept, building upon the generation unit model presented in the previous subsection, is proposed.

1) LOAD CLASSIFICATION METHODOLOGY

Several load classifications have been proposed and employed across various applications to optimize electricity generation.

Concept of each method can be summarized as follows:

(i) K-means clustering: Salimi-Beni [42] clustered the load into three groups using this method. It is an algorithm to iteratively group items to k clusters. Each item will be assigned to the nearest k number of centroids (mean). The centroids are then recalculated. Afterward, each item is reassigned until no more reassignments can take place. In this case, the item is hourly load, and the number of clusters is two. At the end of the clustering, both centroids are used to divide hourly load into three groups. The values that are lower than the minimum cluster are considered as base load while the values that are higher than the maximum cluster are considered as peak load.

(ii) Specific periods in a day clustering: Guo et al. [44] classified the daily demand, based on specific periods in a day. It is defined in [44] that 24 hours in a day is divided into three periods: low-demand load (0:00–8:00), medium-demand load (8:00–16:00) and high-demand load (16:00–24:00).

(iii) Quartile range clustering: Pereira [45] determined these demands through quartile ranges. The quartile range is divided into three limits: the inferior limit, the middle limit or median, and the superior limit. In [45], the first quartile defines the base level, the fourth quartile defines the peak level, and the interquartile range defines the intermediate level.

2) THE PROPOSED LOAD CLASSIFICATION

In this paper, the demand is also classified into 3 groups which are base load, intermediate load, and peak load. The concept of this load classification can be summarized as follows: firstly, since MTU units cannot be freely dispatched but are represented by their respective generation models described in the previous subsection, the demand served by these units can be described by (1). After that, the remaining demand is then supplied by ELU calculated by (4), resulting the net demand. This net demand is then classified into 3 groups and served by the remaining dispatchable generation types. These generation units include ESS, coal-fired, combined cycle, nuclear, gas turbine, and gas engine units. Generally, the base load is provided by generation units that operate continuously, resulting in a high expected plant factor (PF). The PF represents the ratio of electrical energy produced by a generation unit during a specific period to the electrical energy that could have been generated if the unit operated at full power continuously during the same period. On the other hand, peak load demands are met by generation units that operate for short periods, starting and stopping multiple times a day. Consequently, their expected PF is relatively low. Therefore, it seems that the demand can also be classified by the associated expected PF.

In this paper, expected PFs are considered alongside the LDC of the net demand to determine the required capacity of dispatchable peaking as well as base load generation units. Afterward, the capacity of intermediate load generation units is automatically determined. Expected PF can be obtained from the actual historical data of the existing generation units. According to the 2020 Annual Technology Baseline published by the National Renewable Energy Laboratory (NREL) [53], the average PF for gas turbine falls in the range of 12% to 30%, while for combined cycle generation, it ranges from 55% to 88%. Thus, in this paper, the expected PF that distinguishes between peaking and intermediate load units is set at 15%, while the expected PF that distinguishes between intermediate load and base load units is set at 80%. The load classification method proposed in this paper is summarized in Fig. 3.

Detail of the load classification shown in Fig. 3 can be explained as follows:

1) Create an original HRL of the system from the demand forecast and associated hourly load curve.

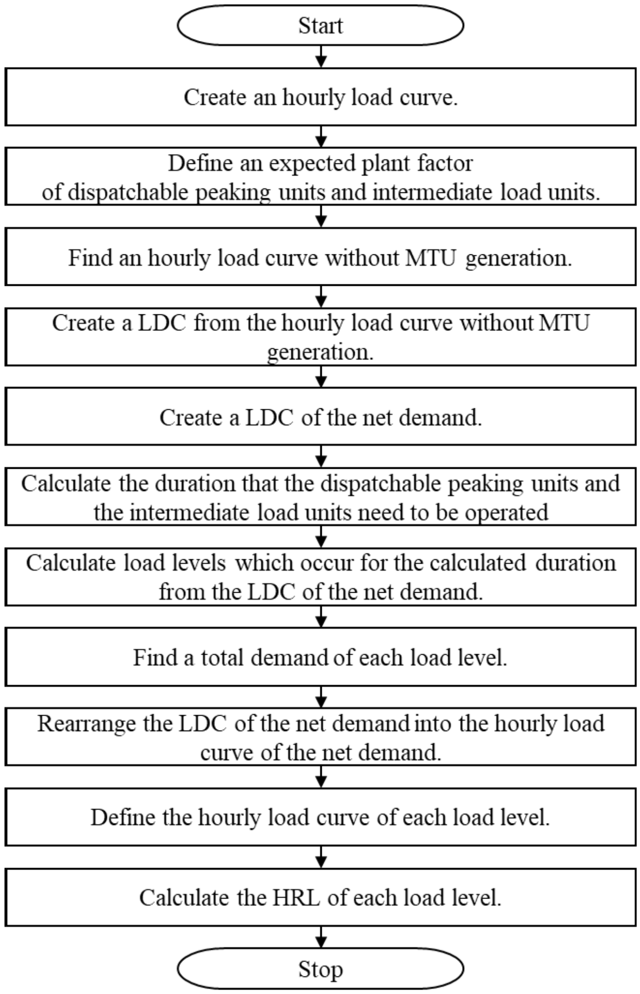

FIGURE 3. Flow chart of the load classification method.

2) Define expected PFs of both dispatchable peaking units and intermediate load units.
3) Create the HRL without MTU by deducting the MTU generation from the original HRL as shown in Fig.4.
4) Create the LDC from the HRL without MTU (LDC^T) from the third step by sorting it in descending order as illustrated by the dash-dotted line in Fig. 5.
5) Create the LDC of the net demand (LDC'^{T}) by shaving the LDC from the fourth step by the UC model of the energy limited unit (ELU), calculated from (3) and (4), as illustrated by the dash line in Fig. 5.
6) Determine the operating durations for the dispatchable peaking units and the intermediate load units based on the expected PFs defined in the second step using (12).

$$\mathrm{DT}_m^l = \mathrm{ePF}_l \times 8,760 \tag{12}$$

7) Determine the load level during the operation of dispatchable peaking units ($\mathrm{LDC}'^{T}_{DT_m^1}$) and the intermediate load units ($\mathrm{LDC}'^{T}_{DT_m^2}$) as indicated in Fig 6.

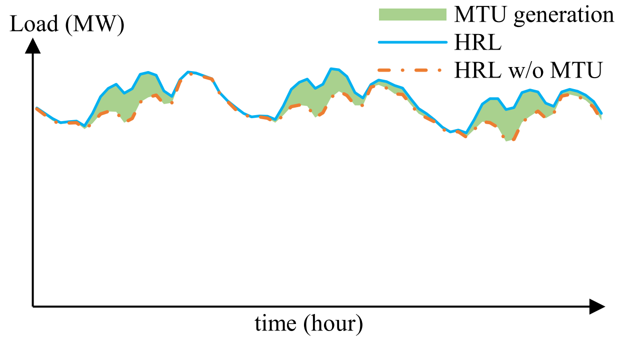

FIGURE 4. The original HRL and the HRL without MTU.

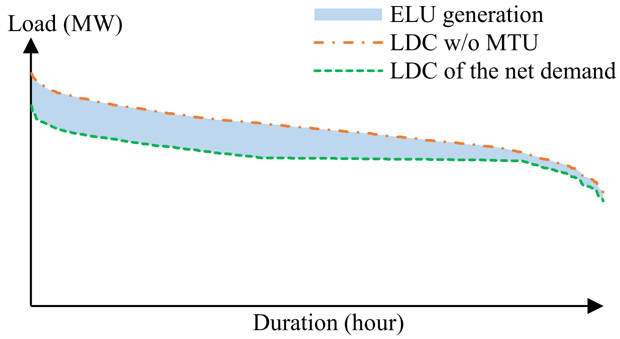

FIGURE 5. The LDC without MTU and the LDC of the net demand.

8) Find the total demand of each load level using the following equations:

$$L^B = \mathrm{LDC}'^{T}_{\mathrm{DT}^2_m} \tag{13}$$

$$L^I = \mathrm{LDC}'^{T}_{\mathrm{DT}^1_m} - \mathrm{LDC}'^{T}_{\mathrm{DT}^2_m} \tag{14}$$

$$L^P = \mathrm{LDC}'^{T}_{1} - \mathrm{LDC}'^{T}_{\mathrm{DT}^1_m} \tag{15}$$

9) Rearrange the LDC of the net demand to form the HRL of the net demand (L_h).

10) Define the HRL of each load level by (16), as each load level is a component of the HRL of the net demand.

$$L_h = L^1_h + L^2_h + L^3_h \tag{16}$$

11) Calculate the HRL of each load level using the following equations:

$$\mathcal{L}_h = \left(L^1_h,\ L^2_h,\ L^3_h\right) \tag{17}$$

$$\mathcal{L}_h = \begin{cases} \left(L_h \quad 0 \quad 0\right), & L_h < L^B \\ \left(L^B \quad L_h - L^B \quad 0\right), & L^B \le L_h < L^B + L^I \\ \left(L^B \quad L^I \quad L_h - L^B - L^I\right), & L^B + L^I \le L_h \end{cases} \tag{18}$$

With the proposed load classification described in the steps 1) – 8), the demand that needs to be supplied by each group of generation type can be illustrated in Fig. 7. Considering that the demands needing supply from must-take units and energy-limited units are calculated from the UC model of those units, it can be inferred that the generation of these units is aligned with their corresponding load.

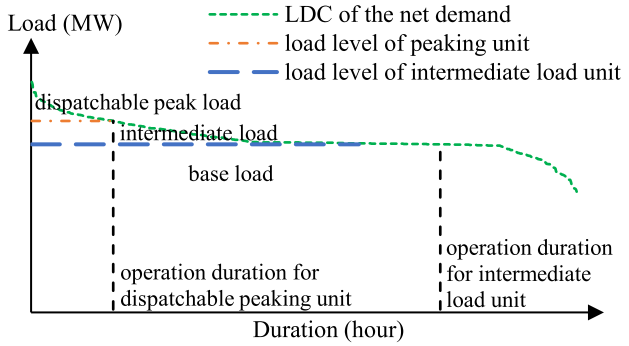

FIGURE 6. Demand classified into dispatchable peaking unit, intermediate load unit, and base load unit.

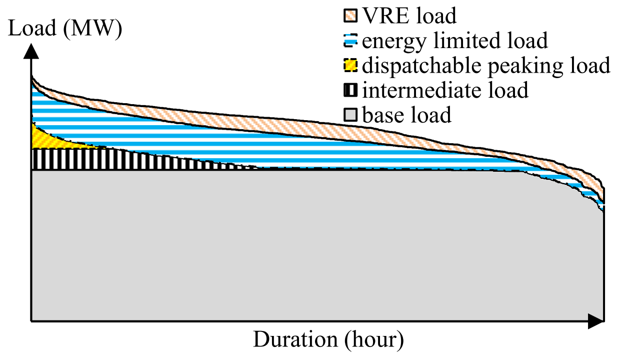

FIGURE 7. Demand classification.

For the hourly net demands described in the step 9) -11), the $\mathcal{L}_h$ is used within the hourly power balance constraints in the linear programming model for UC, which will be described in the next section. The peak HRL (L^1_h) and intermediate HRL (L^2_h) obtained from (18) are also used in peak load power balance constraints and intermediate load power balance constraints respectively, in addition to only the net demand (L_h). Furthermore, the total demand of each load level (L^B, L^I, L^P) is compared to the existing generation capacity of associated generation types in each level to determine if there is enough generation capacity to meet the demand of each load level. It is important to note that in certain power systems with limitations on fuel variability, such as countries with limited access to coal or nuclear fuel, lower-level loads can be supplied by generation types of higher-level loads. This approach can be utilized when necessary, as the ramp rate of higher-level generation types exceeds the fluctuation of lower-level demand. Consequently, dispatchable peaking generation units have the capability to supply all three levels of load. Intermediate generation units are suitable for supplying intermediate and base loads, while base load units are designed only for base loads.

The load classification concept explained in this section will play a crucial role in the linear programming model in the unit commitment solution and the decision-making process for constructing new power plants, as described in the upcoming section. This ensures that the generation system possesses sufficient flexibility to effectively accommodate VRES.

III. GENERATION EXPANSION PLANNING METHOD

The generation expansion planning method used in this paper is based on a linear programming model, initially introduced in [15]. It has been enhanced with additional constraints to provide the required flexibility for addressing VRES. In the model proposed in [15], the decision-making process concerning the additional of new generation units is separated from the optimization model to eliminate integer variables. During each consideration period, which is typically 1 month, a generation unit with the appropriate fuel type and generation type can only be added to the system if certain criteria, such as LOLE, fuel mix, and CO_2 emissions are met. This approach decomposes the complex multi-period MILP problem into multiple subproblems, each focusing on constraints for a single month. Through this separation, solutions to the subproblems associated with each period can be conveniently solved, providing initial state for the subsequent period. The iterative resolution of a sequence of problems and subsequent generation expansion determinations contributes to the formulation of the generation expansion plan.

Decomposing the problem into smaller-scale subproblems, makes it possible to incorporate hourly power balance constraints with renewable energy generation profiles for a whole subperiod, e.g., 720 hours in a month, into the model without imposing significant computational burden. Another advantage of separating the decision-making process from the optimization model is the ability to integrate non-linear power system indices like LOLE during decision-making. With this simplified model, UC problems with VRES and ESS can be addressed alongside other non-linear indices. While this simplification does not guarantee a globally optimal solution, previous findings in [15] demonstrated its efficiency by showing that computational effort is significantly reduced while the obtained solution remains close to the optimal one.

To accommodate VRES, this paper enhances the model introduced in [15] by incorporating multiple load levels balance constraints. Using the load classification method described in the previous section, hourly load of the net demand, broken down into each load level, L_h,obtained from the proposed load classification are integrated into the hourly power balance constraints within the linear programming optimization model for UC problems. As a result, because lower-level loads can be supplied by generation of higher-level loads, this paper will take in account the hourly power balance constraints for both peak load and intermediate load in addition to only the hourly power balance constraint for the total load.

The planning method can be summarized as a flow chart in Fig. 8. It consists of two main parts: UC solution and a decision-making procedure. Details of each part will be described in the following subsection.

A. UNIT COMMITMENT SOLUTION

The purpose of solving UC problems in this paper is to determine if the total demand for the considered period can be met, not only by minimizing generation costs but also satisfying all planning constraints. The UC problems are addressed monthly using the priority list method. This list is generated based on system policies which prioritize must-take generation units and rank generation units by their average generation costs. The objective is to ensure that within a group of generation units sharing the same type, the units with the lowest operating cost are selected for commitment and operation first.

As concerns about climate change rapidly grow, it is increasingly important to prioritize electricity generation from GHG free sources like renewables and hydro power plants. Active DSM policies, including demand response, can help reduce GHG emissions by managing electricity peak demand. Consequently, these clean energy sources should be given priority in the priority list method and should be committed to supply electricity before dispatchable ESS or other generation units. Despite the environmental benefits of GHG free technologies, VRES and other renewable sources, which are considered as must-take generation units, face additional constraints compared to hydro power plants and demand response, categorized as an energy limited unit. As such, priority should be given to must-take generation units over energy limited units in electricity supply.

In comparison to a case study from [15], where a generation expansion plan was created over a decade ago, the penetration of VRES has significantly increased in the present day. Since VRES units are must-take power plants, there may be times when the total power generated from VRES exceeds demand, requiring ESS. However, due to the separation of UC models for VRES and ESS, it becomes essential to transmit the specifics of this excess power from the VRES generation model to the UC problem that considers ESS. This ensures efficient utilization of the excess power. Additionally, not all excess power generated can be fully utilized during periods of low demand. To address this, a slack ESS variable, designed for generation curtailment, is introduced. This slack ESS stores excess power that remains unused by the dispatchable ESS. Importantly, the stored electricity cannot be reintroduced to the grid: rather it serves as information for curtailing VRES generation. This curtailment follows a reverse order from the priority list to comply with hourly power balance constraints. The key characteristics of the slack ESS variable include:

- Availability: always available
- Rated power input (charge): greater than total generation of the considered period
- Rated power output (discharge): zero
- Charging cost: very low (but not zero)

In this paper, a series of UC problems are solved iteratively, with each optimal solution from the current timeslot serving as the initial condition for the subsequent one. To maintain the

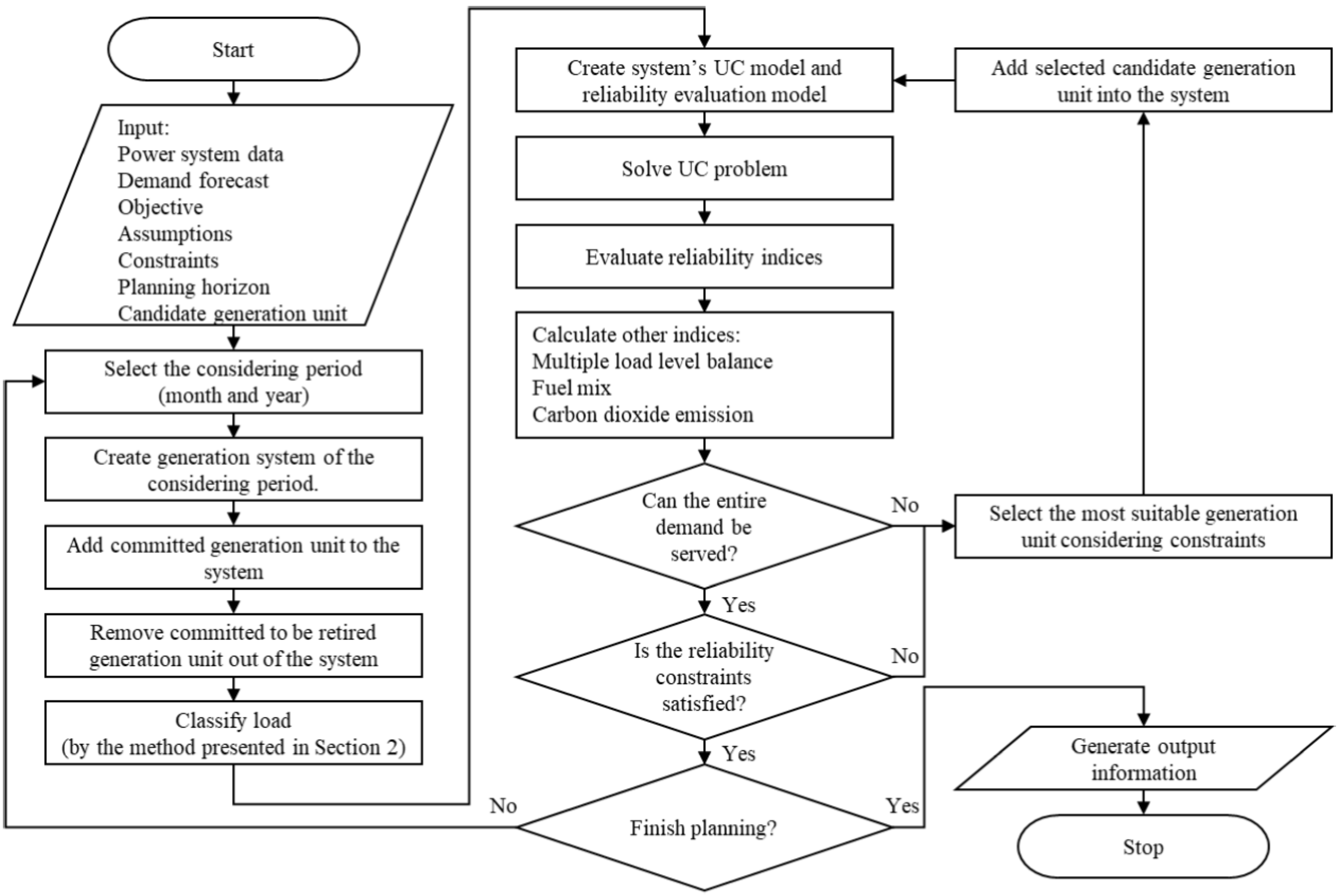

FIGURE 8. **Flow chart of the proposed generation expansion planning method.**

continuity and prevent early termination of the iterative calculation, slack generation variables are introduced to ensure the derivation of optimal solutions. Furthermore, the balance of multiple load levels is taken into account in the UC problem. As a result, this paper incorporates hourly power balance constraints for the peak load and intermediate load, as shown in (21) and (22), in addition to the hourly power balance constraint for the total load, as shown in (23). To satisfy these three hourly power balance constraints – peak load, intermediate load and total load – in the UC problem, it is essential to introduce three specific slack generation variables.

The introduction of these slack generation variables along with slack ESS in this paper enriches the proposed approach to address the UC problem. The methodology is summarized in the flow chart depicted in Fig. 9. The linear programming model considering multiple load levels and ESS for the timeslot of month *m* of year *y* can be found in (19) to (34), as shown at the bottom of the next page.

The objective function of this optimization is to minimize operating costs, as defined in (19). The optimization's constraints include the peak load power balance constraint as defined in (21), the intermediate load power balance constraint defined in (22), the system's hourly power balance constraint defined in (23), fuel-mix ratio constraints defined

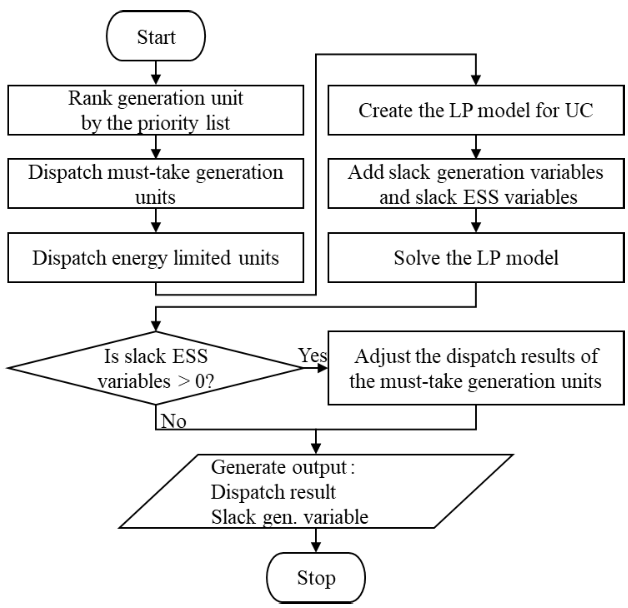

FIGURE 9. **Flow chart of the unit commitment solving method.**

in (24), carbon dioxide emission constraint indicated in (25), ESS operating constraints stipulated in (26) to (31), power generation upper and lower bounds identified in (32), slack generation unit upper and lower bounds specified in (33), and slack ESS unit upper and lower bounds specified in (34). To accommodate VRES, the hourly power balance constraints for peak load and intermediate load are considered. This ensures that the total generation from flexible response units exceeds their corresponding load demands. Moreover, the consideration of the efficiency of ESS units and the cost of electricity generation in the objective function is enough to ensure that ESSs will not be charged and discharged simultaneously. This practice avoids unnecessary losses in the ESS units. Charging and discharging ESSs simultaneously would necessitate additional electricity generation, resulting in higher overall electricity costs, contrary to the objective of minimizing costs. The result of this UC problem is used as input for the subsequent stage of this GEP. Specifically, the statuses of all slack generation units are used to verify whether the hourly power balance constraints can be met. Additionally, the results of the UC will be used to guide the selection of candidate units.

B. DECISION-MAKING PROCESS

To make the generation expansion decision, several indices need to be calculated and compared against predefined criteria. Some of these indices, like fuel-mix ratio and carbon dioxide emission, are already considered during the UC process. However, there is another crucial reliability index, which is LOLE, that indicates when an additional generation unit is needed. LOLE represents the expected number of hours in which the electricity demand exceeds the available generation capacity [54]. In this paper, due to the separation of generation expansion decisions, LOLE constraint can be isolated from the optimization model shown in (19) to (34). The calculation method for system LOLE can be found in [52] and [54], which involves using the modified LDC from (11) and the COPT generated from the generation system during the considered period. The calculated LOLE index is then compared to the predefined reliability criterion. If the LOLE index exceeds this criterion, it triggers the selection of an additional generation unit from a list

$$\min\left(\sum_{f\in F}\sum_{l=1}^{3}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}}\sum_{h=1}^{H_m} e_{f,l,g,j,y}\times P^{D}_{f,l,g,j,h}+\sum_{l=1}^{3}\sum_{h=1}^{H_m} e^{l}_{X}\cdot X^{l}_{h}+\sum_{h=1}^{H_m} e_{Y}\cdot Y_h\right) \tag{19}$$

$$e_{f,l,g,j,y}=\mathrm{FC}_{f,y}\times \mathrm{FX}_{y}\times \mathrm{HR}_{f,l,g,j}+\mathrm{VOM}_{f,l,g,j} \tag{20}$$

Subject to

$$\forall h, l=1:\sum_{f\in F}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}} P^{D}_{f,l,g,j,h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}} P^{\mathrm{dch}}_{s,j,h}\times\eta^{\mathrm{dch}}_{s,j}+X^{1}_{h}\geq L^{1}_{h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}}\frac{P^{\mathrm{ch}}_{s,j,h}}{\eta^{\mathrm{ch}}_{s,j}} \tag{21}$$

$$\forall h:\sum_{f\in F}\sum_{l=1}^{2}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}} P^{D}_{f,l,g,j,h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}} P^{\mathrm{dch}}_{s,j,h}\cdot\eta^{\mathrm{dch}}_{s,j}+X^{1}_{h}+X^{2}_{h}\geq L^{1}_{h}+L^{2}_{h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}}\frac{P^{\mathrm{ch}}_{s,j,h}}{\eta^{\mathrm{ch}}_{s,j}} \tag{22}$$

$$\forall h:\sum_{f\in F}\sum_{l=1}^{3}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}} P^{D}_{f,l,g,j,h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}} P^{\mathrm{dch}}_{s,j,h}\cdot\eta^{\mathrm{dch}}_{s,j}+X^{1}_{h}+X^{2}_{h}+X^{3}_{h}= L_{h}+\sum_{s\in S}\sum_{j=1}^{N_{s,y,m}}\frac{P^{\mathrm{ch}}_{s,j,h}}{\eta^{\mathrm{ch}}_{s,j}}+Y_h \tag{23}$$

$$\forall f:\sum_{l=1}^{3}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}}\sum_{h=1}^{H_m} P^{D}_{f,l,g,j,h}\leq\delta_{f,y,m}\times\sum_{h=1}^{H_m}L_h \tag{24}$$

$$\sum_{f\in F}\sum_{l=1}^{3}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}}\sum_{h=1}^{H_m}\mathrm{EF}_{f}\times\mathrm{HR}_{f,l,g,j}\times P^{D}_{f,l,g,j,h}\leq\varepsilon_{y,m} \tag{25}$$

$$\forall h\forall s\forall j:\mathrm{En}_{s,j,h}=\mathrm{En}_{s,j,h-1}+P^{\mathrm{ch}}_{s,j,h}-P^{\mathrm{dch}}_{s,j,h} \tag{26}$$

$$\forall s\forall j\forall y\forall m:\mathrm{En}_{s,j,1}=\mathrm{SOC}^{0}\times\mathrm{En}^{\max}_{s,j,y,m}\times\mathrm{SOC}^{\max}_{s,j} \tag{27}$$

$$\forall s\forall j\forall y\forall m:\mathrm{En}_{s,j,H_m}=\mathrm{SOC}^{0}\times\mathrm{En}^{\max}_{s,j,y,m}\times\mathrm{SOC}^{\max}_{s,j} \tag{28}$$

$$\forall h\forall s\forall j:0\leq P^{\mathrm{ch}}_{s,j,h}\leq P^{\max}_{s,j} \tag{29}$$

$$\forall h\forall s\forall j:0\leq P^{\mathrm{dch}}_{s,j,h}\leq P^{\max}_{s,j} \tag{30}$$

$$\forall h\forall s\forall j\forall y\forall m:\mathrm{En}^{\max}_{s,j,y,m}\times\mathrm{SOC}^{\min}_{s,j}\leq\mathrm{En}_{s,j,h}\leq\mathrm{En}^{\max}_{s,j,y,m}\times\mathrm{SOC}^{\max}_{s,j} \tag{31}$$

$$\forall h\forall f\forall l\forall g\forall j:P^{D\min}_{f,l,g,j}\leq P^{D}_{f,l,g,j,h}\leq P^{D\max}_{f,l,g,j} \tag{32}$$

$$\forall h\forall l:0\leq X^{l}_{h}\leq\max\left(L_h\right) \tag{33}$$

$$\forall h\forall y\forall m:0\leq Y_h\leq\sum_{f\in F}\sum_{l=1}^{3}\sum_{g\in G}\sum_{j=1}^{N_{f,l,g,y,m}}\sum_{h=1}^{H_m}\mathrm{Cap}_{f,l,g,j,y,m} \tag{34}$$

of candidate generation units to be added to the generation system.

With the solution from the proposed linear programming model for UC and the calculated LOLE, generation system indices such as reliability, fuel availability, and environmental impact can be evaluated. These indices are compared to the predefined criteria and used as indicators for the generation system to make an expansion decision. Initially, a list of candidate generation units is prepared in advance. This list consists of several generation units with different technologies, fuels, or corresponding load levels, providing options for the generation expansion constraints. For example, if multiple hourly power balance constraints are crucial, the candidate list should include generation units for all three load levels. Likewise, if the carbon dioxide emission quota is low, the candidate list should comprise generation units with low or zero carbon dioxide emissions. In this paper, as the priority is placed on considering multiple hourly power balances, candidate lists of all three load levels are separately prepared. Once these lists are ready, generation units in each list are compared based on the objective of total cost minimization. If an additional unit is needed, the generation unit with the least total cost that does not violate other planning constraints is selected. In this paper, LCOE is used to compare the total costs of candidate generation units.

$$\mathrm{LCOE}_{f,l,k} = \frac{\mathrm{Cap}_{f,l,k,0} \times I^{0}_{f,l,k} + \sum_{t=1}^{\mathrm{SL}_{f,l,k}} \frac{\mathrm{CF}_{f,l,k,t}}{(1+r)^t}}{\sum_{t=1}^{\mathrm{SL}_{f,l,k}} \frac{E_{f,l,k,t}}{(1+r)^t}} \tag{35}$$

$$\mathrm{CF}_{f,l,k,t} = \mathrm{EP}_{f,l,k,t} + \mathrm{FC}_{f,l,k} + \mathrm{VC}_{f,l,k,t} \tag{36}$$

$$\mathrm{EP}_{f,l,k,t} = \mathrm{FC}_{f,y(t)} \times \mathrm{HR}_{f,l,k} \times E_{f,l,k,t} \tag{37}$$

$$\mathrm{FC}_{f,l,k} = \mathrm{FOM}_{f,l,k} \times \mathrm{Cap}_{f,l,k,0} \tag{38}$$

$$\mathrm{VC}_{f,l,k,t} = \mathrm{VOM}_{f,l,k} \times E_{f,l,k,t} \tag{39}$$

$$E_{f,l,k,t} = \mathrm{Cap}_{f,l,k,t} \times \mathrm{ePF}_{f,l,k} \times 8,760 \tag{40}$$

The LCOE for a generation unit is calculated using (35). This cost includes fuel cost or energy cost ($\mathrm{EP}_{f,l,k,t}$), fixed O&M cost ($\mathrm{FC}_{f,l,k}$), and variable O&M cost ($\mathrm{VC}_{f,l,k,t}$) as outlined in (36) – (39). Notably, the fuel cost in (37) is the same as the fuel cost used in the UC model. As the fuel cost may vary over the candidate units' service life, the index t representing the year in the service life of the candidate unit needs to be converted into the year in the planning horizon to determine the fuel price of the year y. The expected generated electricity of candidate generation units is calculated using the expected plant factor and capacity, as shown in (40). The expected plant factors used in this equation are the same as the expected plant factors used in load classification. The expected plant factor of base load unit is set to 90%. If power degradation is considered, the capacity in each service year t, denoted $\mathrm{Cap}_{f,l,k,t}$ should be adjusted accordingly.

The candidate generation units are ranked based on the LCOE calculation. This rank aids the decision-making process, which can be divided into two parts. The first part involves checking whether generation expansion is necessary during the specified period. The second part is the selection of suitable candidate units. Criteria for generation expansion include determining whether the existing generation can meet the entire demand while satisfying all planning constraints, along with the reliability index meeting the required criterion. Considering multiple load levels balance constraints, the criteria for generation expansion also include the ability of generation units in each load level to supply their corresponding demand. If any of these criteria is not met, it indicates the need for an additional generation unit. This process is illustrated in Fig. 8.

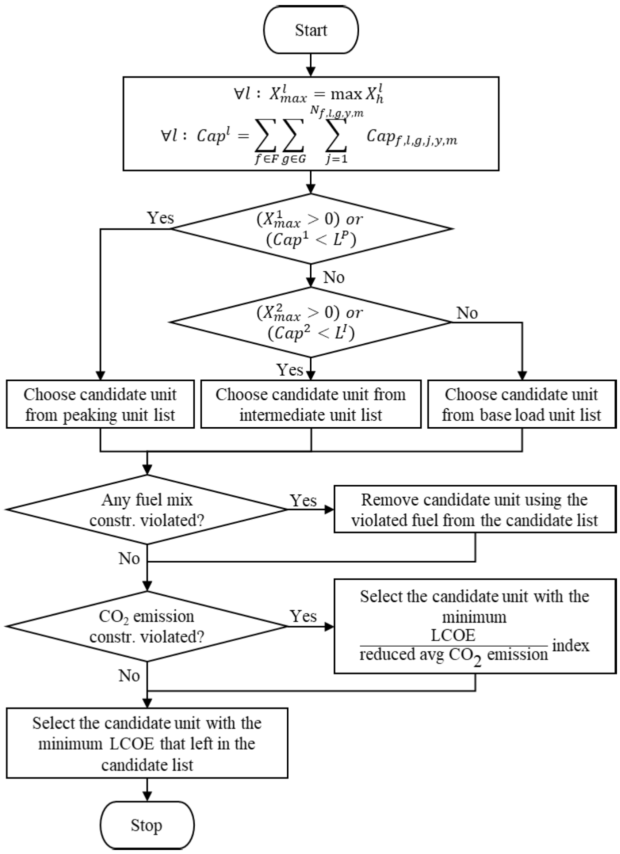

FIGURE 10. Shortlisting process for candidate unit selection.

When an additional generation unit is required, the selection process involves choosing a candidate list and shortlisting units. This selection process can be summarized in Fig. 10.

From Fig. 10, the goal of selecting a candidate list is to ensure that the additional unit possesses the necessary characteristics to meet multiple power balance constraints and the requirement that the total generation capacity in each load level exceeds the total demand of that level. The selected candidate units are then shortlisted to include only those that, if chosen, do not violate any planning constraints. From this shortlist, the candidate unit with the lowest LCOE is selected as a suitable candidate unit for commissioning into the generation system. This decision-making process

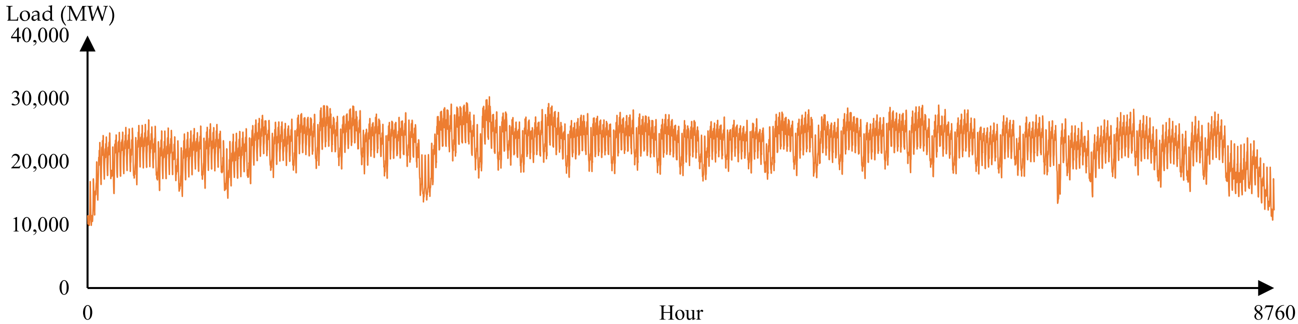

FIGURE 11. Full-year hourly load curve of 2017.

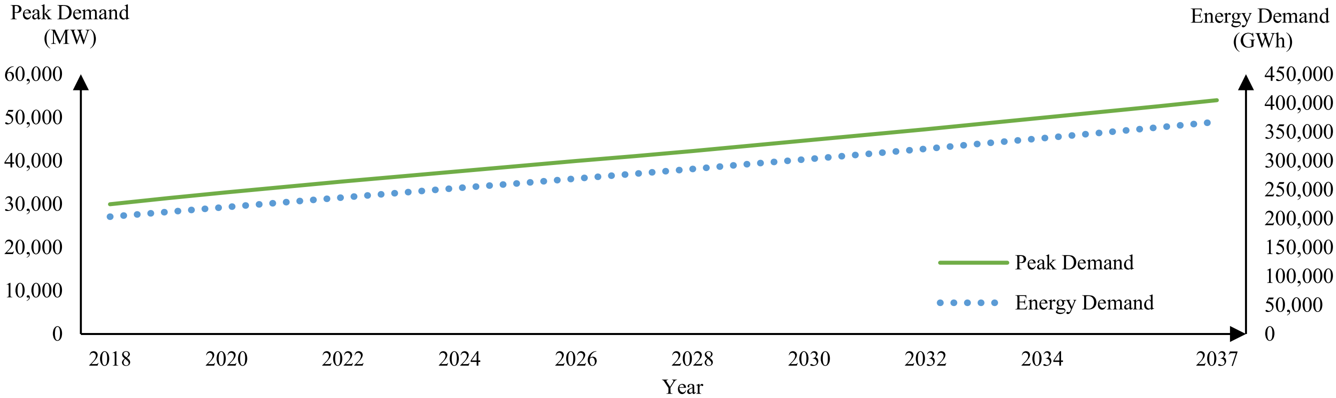

FIGURE 12. Peak demand and energy demand forecast of PDP2018r1.

repeats iteratively until all generation expansion criteria are met.

The shortlisting process ensures the selection of only one suitable candidate unit at each iteration. This confirms that additional units are commissioned into the generation system only if necessary. With these proposed processes, GEP with the integration of VRES while considering multiple load levels balance constraints can be achieved with minimal computational effort. The proposed method will be tested using the case study introduced in the next section.

IV. TEST SYTEM: THAILAND's PDP2018r1

This section presents a test system with data from the generation system and planning assumptions. The generation system used for the case study in this paper is based on Thailand's Power Development Plan 2018 revision 1 (PDP2018r1), which was published in 2020 [48]. The planning period covered by PDP2018r1 spans from 2018 to 2037. Details of the generation system and assumptions are provided in the following subsections. The exchange rate used in this paper is 33 USD/THB throughout the planning horizon.

A. LOAD MODEL AND LOAD FORECAST DATA

The load model used in the UC problem is a full-year hourly load curve. It is created from the full-year hourly load curve of the base year and load forecast data. In this paper, Thailand's actual full-year hourly load curve of 2017, having a peak load of 30,303 MW, is employed as the load model, as shown in Fig. 11. Load forecasts for the year 2018 to 2037 are provided in PDP2018r1, as illustrated in Fig. 12.

TABLE 2. PHS parameters.

Parameters	Value	Unit
C-rate	0.125	-
Round trip efficiency	80	%
Minimum state-of-charge	0	%
Maximum state-of-charge	100	%

B. EXISTING GENERATION UNITS

In this paper, the generation system as of December 31, 2017, is considered as the initial (existing) system. The list of generation units in the existing system can be found in PDP2018r1 [48]. A summary of these existing units is provided in APPENDIX A. Within this existing system, there are two PHS units with their parameters detailed in Table 2.

C. COMMITTED GENERATION UNITS

Committed generation units refer to those units that are already scheduled for commissioning into the generation system. These units can be categorized into two groups: units with signed contracts and units that are committed based on

TABLE 3. List of peaking candidate units.

Technology (fuel type)	Capacity (MW)	Service life (year)	Heat rate (Btu/kWh)	FOR (%)
GT (NG)	250	25	11,1138	4

TABLE 4. List of intermediate candidate units.

Technology (fuel type)	Capacity (MW)	Service life (year)	Heat rate (Btu/kWh)	FOR (%)
CCGT (NG)	700	25	6,284	4

TABLE 5. List of base load candidate units.

Technology (fuel type)	Capacity (MW)	Service life (year)	Heat rate (Btu/kWh)	FOR (%)
CCGT (NG)	700	25	6,284	4
Thermal (Coal)	1,000	30	8,869	5.5

policies or plans. In addition to the committed units, some of the existing units are planned for retirement. Comprehensive details about committed and retired units are available in PDP2018r1 [48], with a summary provided in APPENDIX B.

D. CANDIDATE GENERATION UNITS

Candidate generation units are predefined units that will be selected for commissioning under specified conditions:

- the existing generation cannot meet the entire demand while satisfying all constraints.
- the reliability index fails to meet the reliability criterion.

This list comprises several generation units with different technologies, fuels, or characteristics, providing options to fulfill the generation expansion plan. Generally, the list should include generation units that adhere to the planning constraints, ensuring a solution for the GEP. In this paper, three candidate lists of peaking units, intermediate units, and base load units are separately prepared due to the three-level of hourly load balance constraints. These lists are shown in Table 3, Table 4 and Table 5. In table 5, due to a CO_2 emission constraint, a CCGT unit must be added to the base load list as a low-emission option.

E. GENERATION PROFILE

A 1-MW generation profile is employed to construct a UC model for those must-take generation units. Further information about the generation profiles used in this paper can be found in PDP2018r1 [48].

F. PLANNING CRITERIA

To ensure that the generation expansion plan covers the designated planning horizon while maintaining acceptable levels of availability, reliability, and emissions, the following criteria are taken into account in the case study of this paper:

- Planning horizon: 2018 to 2037
- Reliability criteria: LOLE $\leq$ 0.7 days/years

TABLE 6. Carbon dioxide emission factor of fuel.

Fuel	Carbon dioxide emission factor ($kgCO_2$/MMBtu)
Lignite	95.9
Bituminous	94.4
Natural gas	57.3
Imported coal	0.0
Diesel	76.6
Oil	79.7

- Fuel-mix constraint: None
- Carbon dioxide emission constraint: The average carbon dioxide emission per unit of electricity generated must not exceed 0.413 $kgCO_2$/kWh in 2018 and should be reduced to 0.271 $kgCO_2$/kWh in 2037. The criteria of other years are linearly projected.

The carbon dioxide emission factors of the fuels used in this paper are provided in Table 6.

G. PRIORITY LIST FOR UNIT COMMITMENT

In this paper, generation units within the generation system are committed and dispatched based on their generation technology, priority list, and operating cost. The priority list for the UC problems used in this paper is as follows:

1) VRES
2) Biofuel power plant
3) Generation unit with a firm contract and predefined operational plan
4) Energy-limited unit such as hydro power and DR
5) Dispatchable generation units and ESSs

V. RESULTS AND DISCUSSION

In this section, the results from the proposed methods, tested with the data and assumptions provided in the earlier section, are presented and discussed. First, the impact of VRES penetration and system demand on load classification is presented. Then, the generation expansion plan created by the proposed method using data from the proposed case study will be presented and discussed. Lastly, uncertainties of assumptions are incorporated into the GEP to confirm the computational effectiveness of the proposed methodology.

A. IMPACT OF VRES PENETRATION

In this subsection, a sensitivity analysis involving variation of VRES penetration is presented and discussed using the system in 2030 of Thailand's PDP2018r1. The detail of the analysis are as follows:

- Variation: additional solar PV is commissioned to the generation system by 1,000 MW in each step from 1,000 to 15,000 MW
- System demand is constant.

With the mentioned variations, the percentages of energy generated from VRES compared to system energy demand are computed. Then, demands for each load level – peak, intermediate, and base – corresponding to the penetration of

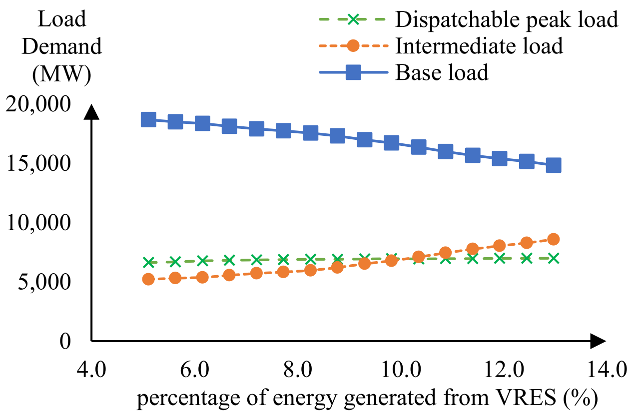

FIGURE 13. **Total demands associated with percentage of energy generated from VRES.**

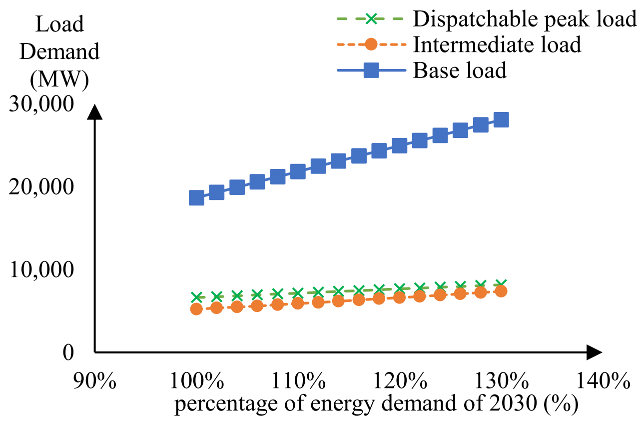

FIGURE 14. **Total demands associated with peak load of the system.**

VRES are determined using the load classification method proposed in section II. The results are presented in Fig. 13. It can be seen that although the system demand remains constant, the demands of dispatchable peak and intermediate loads increase as the percentage of energy generated from VRES increases, while the demand of the base load decreases. These increases in dispatchable peak and intermediate load and the decreases in the base load imply that when there is more VRES capacity in generation system, there is a preference for more fast-response units – peaking units and intermediate units – rather than relying on the base load unit. Additionally, it can be inferred that with higher VRES penetration, more peaking and intermediate units will be commissioned into the generation system. This conclusion aligns with the assumption that the generation system requires more flexibility units with higher VRES penetration.

B. IMPACT OF SYSTEM DEMAND

In addition to the previous sensitivity analysis, another sensitivity analysis involving variation in the system's demand using the system in 2030 of Thailand's PDP2018r1 is presented and discussed in this subsection. The details of the analysis are as follows:

- Variation: peak and energy demand are increased by 2 % in each step from 2% to 30%
- The generation system has not changed.

With the mentioned variation, demands for each load level – peak, intermediate, and base – corresponding to the percentage of energy demand in 2030 are illustrated in Fig. 14.

It can be seen that when the generation system remains unchanged, demands of all three load levels increase with the increase of system energy demand. However, the increase in base load is significantly higher compared to the other two levels. This indicates that as the system demand increases, generation units at every level are required to meet higher demand. However, since the capacity of VRES remains constant, the required capacity of peaking units and intermediate units is not as high as that of the base load unit.

The results obtained in subsections -A and -B, which focused on VRES penetration and demand variation, confirm that the proposed load classification can effectively determine the required flexible capacity needed in the generation system. It can distinguish between impacts from increased system demand and the increased VRES penetration. Next, the classified load from the proposed method will be integrated into the GEP outlined in section III, using data described in section IV.

C. GENERATION EXPANSION PLANNING

In this section, two generation expansion plans created by the method proposed in [15] (Case 1), which is a method that is not taken flexibility of generation system into account, and the GEP considering multiple load levels balance constraints proposed in this paper (Case 2) are presented and compared using data from the test system. First, the list of the additional generation units of both cases can be found in TABLE 7.

From Table 7, it is evident that the total additional capacity in both cases is the same. In Case 1, the selection of additional units depends on the availability of CO_2 emissions quota during the consideration period. Since the LCOE of the thermal unit is lower than that of the CCGT unit, the thermal unit is chosen when generation expansion is required, and the CO_2 emissions quota is still available. Conversely, if the CO_2 emissions quota is insufficient, the CCGT unit is preferred. In this case study, the CO_2 emissions constraints are not stringent throughout the planning horizon. Consequently, only thermal units are selected to be commissioned. In contrast, in Case 2, where multiple load level balance constraints are considered, peaking units (GT unit) are chosen to meet the demand of the peak load if these constraints are not satisfied. As a result, most of the additional units are peaking units, with only one base load unit commissioned in 2037.

Considering the commissioning time of additional units, in Case 1, the first additional unit is scheduled to be commissioned in 2032 because there are committed units already planned for installation from 2018 to 2029 to serve the increasing demand. Then, all additional units are scheduled to

TABLE 7. List of additional units of Case 1 and Case 2.

Year	Case 1		Case 2		
	Thermal (coal)	CCGT (NG)	Thermal (coal)	CCGT (NG)	GT (NG)
2018	-	-	-	-	3,500
2019	-	-	-	-	750
2020	-	-	-	-	-
2021	-	-	-	-	-
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	250
2027	-	-	-	-	-
2028	-	-	-	-	250
2029	-	-	-	-	250
2030	-	-	-	-	500
2031	-	-	-	-	250
2032	1,000	-	-	-	-
2033	2,000	-	-	-	-
2034	1,000	-	-	-	-
2035	1,000	-	-	-	-
2036	-	-	-	-	-
2037	2,000	-	1,000	-	250
Total	7,000		7,000		

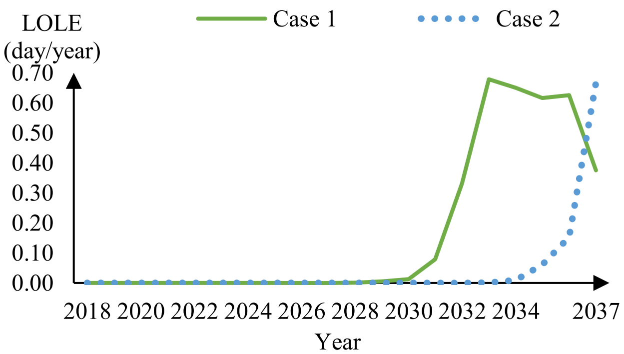

FIGURE 15. Comparison of LOLE of Case 1 and Case 2.

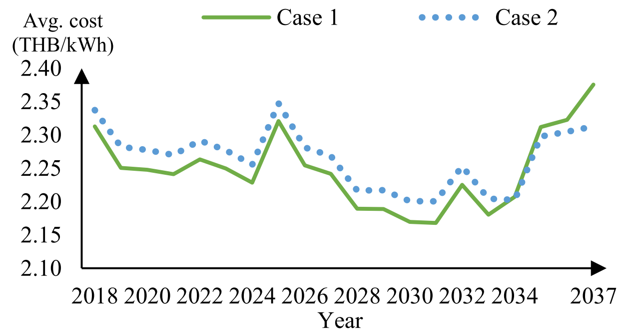

FIGURE 16. Comparison of electricity cost of Case 1 and Case 2.

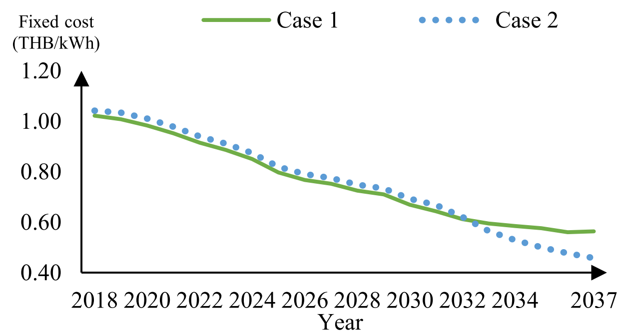

FIGURE 17. Comparison of average fixed cost of Case 1 and Case 2.

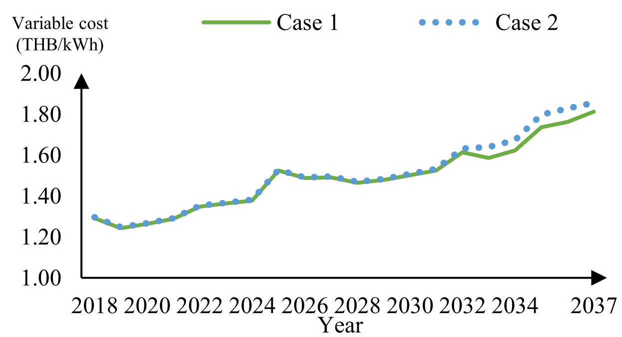

FIGURE 18. Comparison of average variable cost of Case 1 and Case 2.

be commissioned from 2032 to 2037. However, in Case 2, the first additional unit is scheduled to be commissioned in 2018, the first year of the planning horizon. Moreover, half of the additional units are scheduled to be commissioned in 2018. This indicates that the existing system lacks the necessary amount of flexible generation units to satisfy the multiple load levels balance constraints. Other additional small gas turbine units are scattered throughout the plan, with approximately one to two units (250 to 500 MW) commissioned annually. Only one large thermal unit is commissioned in 2037.

The results of LOLE, average electricity cost, and CO_2 emissions for both cases are illustrated in Fig.15 to Fig. 19, respectively.

In Fig. 15, it can be observed that prior to 2030, the LOLE indices for both cases are very low due to the well-planned generation capacity of existing system and the commissioning of committed units. Starting from 2031 onwards, the LOLE of Case 1 begins to increase due to rising demand and the retirement of some existing power plants. Consequently, additional units are scheduled for commissioning from 2032 onwards to replace the decommissioned units and expand the generation capacity, meeting the increasing demand while maintaining system reliability below criterion of 0.7 day/year. In contrast, in Case 2, due to the commissioning of several GT units in 2018 and 2019, its LOLE in 2031 and 2032 are considerably lower than that of Case 1. Moreover, the scattered commissioning of GT units in Case 2 results in its LOLE being lower than that of Case 1 because the total generation capacity of Case 2 exceeds that of Case 1 at any point in the planning horizon except for the last year. Additionally, higher FOR of thermal units, compared to GT or CCGT units, also contributes to the difference in LOLE between both cases. In 2037, the reason for the LOLE of Case 2 being higher than that of Case 1 is the commissioning of the last thermal unit

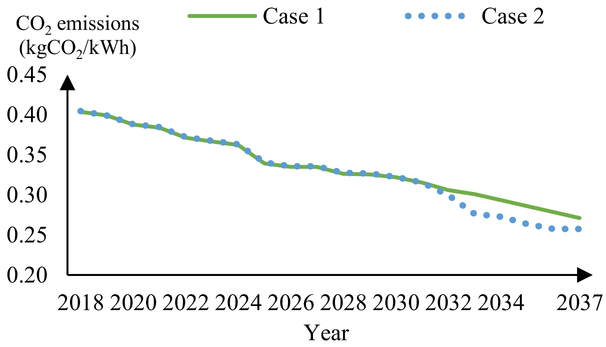

FIGURE 19. Comparison of CO_2 emissions of Case 1 and Case 2.

in Case 2 occurring in September, preventing this unit from contributing to system reliability during the peak demand period in Thailand, which typically occurs from March to June.

As seen in Fig. 16 to Fig. 18, from 2018 to 2033, the average electricity cost of Case 2 is consistently higher than that of Case 1. This is due to two main reasons. Firstly, the LCOE of the GT unit is higher than that of thermal and CCGT units, primarily because of its higher heat rate. Secondly, the total generation capacity of Case 2 is higher than that of Case 1 at almost every point in the planning horizon, leading to a higher investment cost for the generation system and contributing to a higher average electricity cost in Case 2. However, from 2034 to 2037, the average electricity cost of Case 1 is higher than that of Case 2, caused by the higher investment cost of thermal units compared to GT units, as shown in Fig. 17.

In Fig. 19, it can be observed that from 2018 to 2032, CO_2 emissions in Case 2 are slightly higher than that of Case 1. This is primarily because the GT unit, which is used to supply peak demand in Case 2, has a higher heat rate compared to the committed CCGT unit. From 2033 onwards, the difference in CO_2 emissions becomes more pronounced, mainly due to the commissioning of coal-fired thermal units in Case 1, which have higher CO_2 emissions compared to the GT units installed in Case 2.

In Case 2, although there is an indication that the existing system requires a substantial number of flexible units to meet the multiple load level balance constraints, the generation system of Thailand can adequately supply its demand from 2018 to 2022. In practice, this can be achieved by operating the system with a high level of spinning reserve or dispatching only an open-cycle gas turbine (OCGT) from the combined cycle power plant. While these methods provide the necessary flexibility to manage demand fluctuations and the intermittency caused by VRES, ensuring the stability of the generation system, they create inefficiencies in the generation operation and control. However, the addition of many GT units during the early stages of the plan could lead to unnecessary investment in a generation system that is already reliable, resulting in an unnecessary increase in the cost of electricity. Therefore, these findings suggest that the proposed method may need some modification, especially during the transition period from a fossil-based system to a renewable energy-based system.

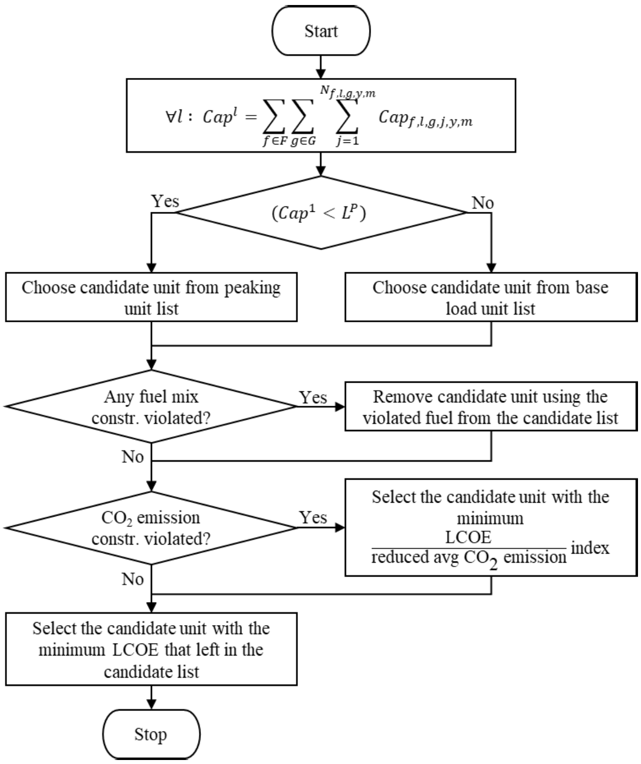

FIGURE 20. The new shortlisting process for candidate unit selection.

D. MODIFIED GENERATION EXPANSION PLAN DURING TRANSITION PERIOD

To enhance the practicality of the proposed GEP method during the transition period and prevent the addition of excessive GT units in the early stage of the plan, a relaxation of the multiple load level balance constraints from the generation expansion criteria is applied to the proposed method. Since generation units of other levels can supply peak load demand through an increase in spinning reserve and the operation of OCGT, constraints (21) and (22) can be omitted from the UC problem. This results in the slack generation variables for peak load (X_h^1) and intermediate load (X_h^2) becoming zeros, and their consideration in the decision-making process can be disregarded. Consequently, the sufficiency of fast-response capacity is only considered in the decision-making process by comparing the total generation capacity in each load level and the total demand of that level as shown in Fig. 10.

With this relaxation, the conditions for generation expansion are simplified to whether the existing generation can meet the entire demand while satisfying all constraints, and whether the reliability index meets the required criteria, without considering multiple load level balance constraints. As a result, a fast-response unit may be commissioned into the

TABLE 8. List of additional units of Case 2 and Case 3.

Year	Case 2			Case 3		
	Thermal (coal)	CCGT (NG)	GT (NG)	Thermal (coal)	CCGT (NG)	GT (NG)
2018	-	-	3,500	-	-	-
2019	-	-	750	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	250	-	-	-
2027	-	-	-	-	-	-
2028	-	-	250	-	-	-
2029	-	-	250	-	-	-
2030	-	-	500	-	-	-
2031	-	-	250	-	-	-
2032	-	-	-	-	-	250
2033	-	-	-	-	-	2,250
2034	-	-	-	-	-	1,000
2035	-	-	-	-	-	750
2036	-	-	-	-	-	750
2037	1,000	-	250	1,000	-	1,000
Total	7,000			7,000		

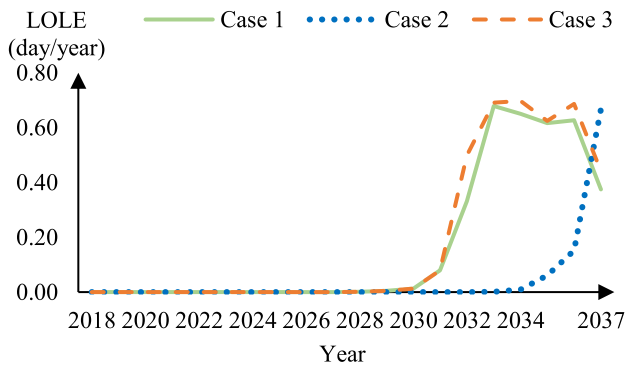

FIGURE 21. Comparison of LOLE of all cases.

generation system only if an additional unit is needed, and the total generation capacity of fast-response units is less than the total demand of their corresponding load. Moreover, currently, the CCGT unit is typically operated in both intermediate and base loads. Therefore, additional relaxation can be applied by focusing solely on the peak load and neglecting the intermediate load. The refined shortlisting process is illustrated in Fig. 20.

With the proposed relaxation, a new generation expansion plan, denoted as Case 3, is formulated. The additional units, LOLE, average electricity cost, and CO_2 emissions of Case 3 are then compared to those of Case 1 and Case 2, as presented in Table 8 and Fig. 21 to Fig. 25. Analysis of Table 8 reveals that the total additional capacity and the selection of additional units are consistent across both cases. However, a notable distinction lies in the commissioning year of additional units. In Case 3, the first additional unit is scheduled to be commissioned in 2032. This contrasts with Case 2, where the first additional unit is set to be commissioned in

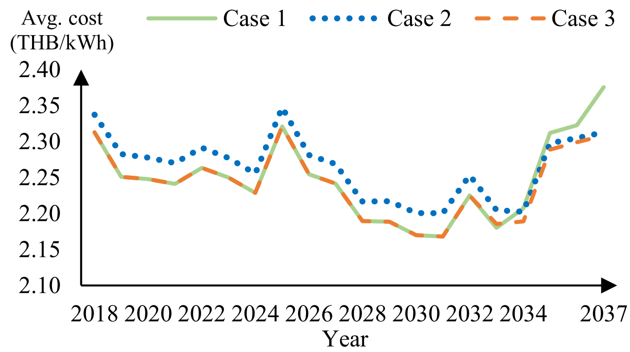

FIGURE 22. Comparison of average electricity cost of all cases.

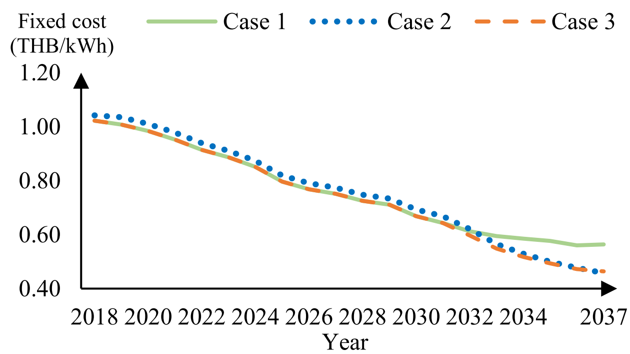

FIGURE 23. Comparison of average fixed cost of all cases.

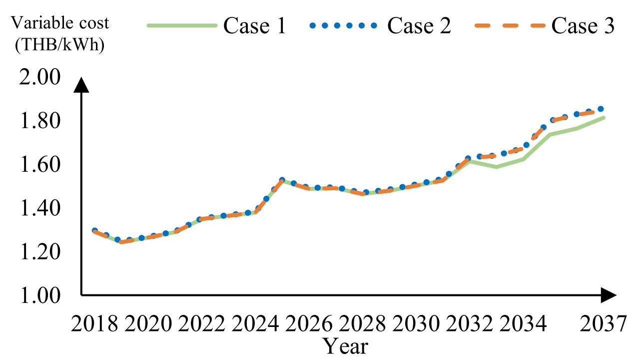

FIGURE 24. Comparison of average variable cost of all cases.

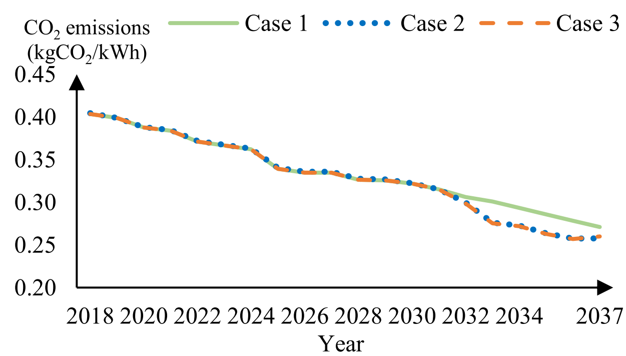

FIGURE 25. Comparison of CO_2 emissions of all cases.

2018. The delay in commissioning in Case 3 is attributed to the neglect of multiple load level balance constraints in the UC. Accordingly, the first additional unit in Case 3 is

TABLE 9. Joint probability density function for load and solar power generation uncertainties.

Parameters		% of load forecast of 2037 (Associated probability)		
		97% (0.25)	100% (0.5)	103% (0.25)
% of solar power generation (Associated probability)	90% (0.25)	0.0625	0.125	0.0625
	100% (0.5)	0.125	0.25	0.125
	110% (0.25)	0.0625	0.125	0.0625

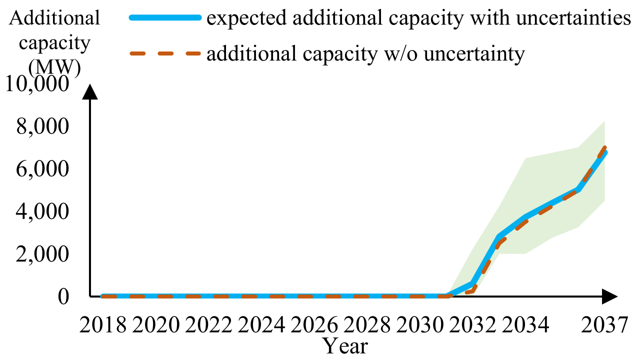

FIGURE 26. Comparison of additional capacity of Case 3 with and without uncertainties.

scheduled for commissioning when the LOLE exceeds the planning criteria for the first time.

In Fig. 21, it is evident that from 2032 to 2037, the LOLE values for Case 3 are similar but slightly higher than those for Case 1. This is due to the differing capacities of GT units and of thermal units. The smaller capacity of GT units results in a less pronounced reduction in LOLE compared to thermal units, contributing to the observed difference between Case 3 and Case 1.

In Fig. 22, it is evident that the average electricity costs of Case 3 are either equal to or slightly lower than those of Case 1 and Case 2 throughout the planning horizon. Considering Fig. 23 and Fig. 24, it can be observed that from 2033 to 2037, the average fixed and variable costs of Case 3 are nearly the same as those of Case 2, as both cases involve the addition of the same type of units.

In Fig. 25, it can be seen that CO_2 emissions in Case 2 and Case 3 are similar as both cases involve the addition of the same type of units. From 2032 onward, the CO_2 emissions in Case 1 are obviously higher than those of other cases.

The results in this subsection indicate that the proposed relaxation method effectively provides the generation system with adequate fast-response units while avoiding excessive early investments, as seen in Case 2. Consequently, the cost of electricity in Case 3 is lower than that in Case 2, and nearly the same as that in Case 1 except in the last planning year, while meeting other planning criteria.

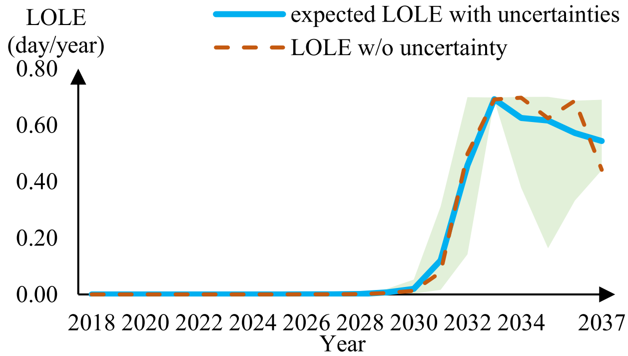

FIGURE 27. Comparison of LOLE of Case 3 with and without uncertainties.

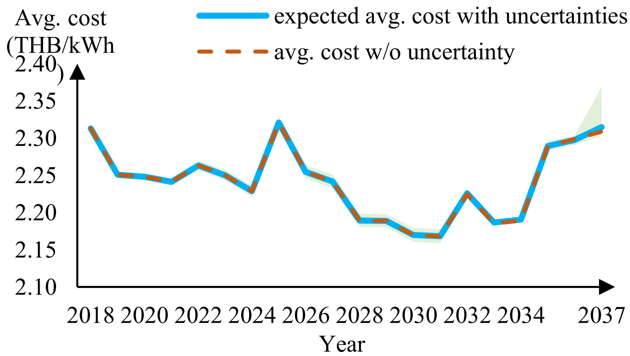

FIGURE 28. Comparison of average electricity cost of Case 3 with and without uncertainties.

E. GENERATION EXPANSION PLAN WITH UNCERTAINTY

In this section, the impact of uncertainties on GEP is investigated using the proposed method. The relaxation option is considered. Two uncertainties related to the response of generation units are considered. The first one is the load forecast uncertainty. Assuming a probability of 0.5 for the forecasted value, and given that the demand in the final year, 2037, can either increase or decrease by 3% with a probability of 0.25, the deviations in the load forecast for other years are linearly modeled accordingly. The second uncertainty pertains to solar power generation. Forecasted generation profiles of all solar units are provided with a probability of 0.5, and they are permitted to fluctuate by 10% around their forecasted profiles with a probability of 0.25. As these uncertainties are independent of each other, a joint probability density function (PDF) can be created, as shown in Table 9.

With these uncertainties, nine scenarios of generation expansion plans are created using data from the test system, modified to account for the uncertainties. To illustrate the impact of these uncertainties, the minimum, maximum, as well as the expected values of generation system indices from all nine scenarios are depicted as boundaries, shown with shaded areas and a dotted line in the following figures. The results of Case 3 with uncertainties, compared with Case 3 using the forecasted value, can be found in Fig. 26 to Fig. 29.

TABLE 10. Summary of existing generation system as of December 2017.

Fuel type & generation type	Number (unit)	Total capacity (MW)	Service life (years)	Heat rate (Btu/kWh)	FOR (%)
Lignite	10	3,653.0	30 - 39	9,100 – 10,600	5.5
Bituminous	14	2,406.6	21 - 30	6,800 – 9,100	5.5
Natural gas (CCGT)	107	28,401.7	20 - 30	6,800 – 9,500	4.0, 5.5
Diesel (GT)	7	60.7	25	8,300 – 10,400	10.0
Fuel oil	2	320	21 - 30	8,300 – 10,400	5.5
Domestic hydro	17	2,926.78	50	-	4.0
Imported coal	3	1473	30	9,100	5.5
Imported hydro	4	2,104.6	25 - 50	-	4.0
PHS	1	500	50	-	6.55
HVDC tie line	1	300	25	-	4.0
Renewable energy	-				

TABLE 11. Summary of renewable energy generation unit as of December 2017.

Fuel type	Total capacity (MW)	Service life (years)	FOR (%)
Biogas	319.7	25	8.0
Biomass	1,659.1	21 – 25	5.5, 8.0
Small hydro	100.6	25 – 50	6.55
Solar	2,572.6	25	0.6
Waste	175	25	8.0
Wind	589.69	25	0.8

TABLE 12. Summary of committed conventional generation units (MW).

Year	Lignite	Bituminous	CCGT (Natural gas)	Oil	Imported Hydro	PHS	Demand response
2018	600.0	20.0	622.0				
2019			1856.8	5.0	1,843.0	500.0	
2020			1,476.0				
2021		10.0	1,550.0				
2022			1,310.0		514.0		
2023			1,280.0				
2024		90.0	2,100.0				
2025		30.0	1,380.0				
2026	600.0		700.0		700.0		
2027			2,640.0				
2028			700.0		700.0		
2029			700.0				
2032					700.0		354.0
2033					700.0		202.0
2034							859.0
2035			700.0		700.0		1,025.0
2036							860.0
2037							700.0

In Fig. 26, the deviation in additional capacity begins in 2032 when the first additional unit is commissioned. This deviation increases as the planning horizon progresses, primarily due to the growing error in the demand forecast. By 2037, the additional capacity falls within the range of 4,500 to 8,250 MW, with an expected value of 6,766 MW.

In Fig. 27, the fluctuation of LOLE becomes noticeable from 2029 onwards. The maximum range of this fluctuation is approximately 0.56 days/year in 2032, primarily due to the difference in demand and generation capacity in each year of each scenario.

From Fig. 28 and Fig. 29, it is evident that the range of both the average electricity cost and the CO_2 emissions is very low. This low variability is attributed to the consistent fuel mix of the generation system in each scenario, which is influenced by planning constraints, mainly those related to CO_2 emissions. Additionally, the proportion of electricity generated from solar capacity is relatively low, ranging from around 5% to 7%. Therefore, the uncertainty of solar power generation does not significantly impact these metrics.

Moreover, the results obtained from using only forecasted data are slightly lower than their corresponding expected values, even though they are calculated from the symmetric joint probability distribution shown in Table 9.

F. COMPUTATIONAL COST

The generation expansion plans described herein were created using a MATLAB program and solved on a single

TABLE 13. Summary of committed conventional generation units (MW).

Year	Biogas	Biomass	Small Hydro	Solar	Waste	Wind
2018	26.4	105.4	42.0	0.3	109.0	763.0
2019	20.0	243.0	1.3	154.0	41.0	135.0
2020	300.0	242.0	2.5	295.0	59.0	
2021	166.0	348.0	14.0	162.0		16.0
2022	133.0	160.0		140.0	400.0	90.0
2023	100.0	160.0	18.0	154.0		90.0
2024	100.0	100.0		130.0		90.0
2025			6.0			
2026			4.0	298.0		
2027			4.0	50.0		
2028			6.0	850.0		
2029			2.0	1,930.0		
2030		400.0	4.0	1,200.0		
2031	50.0	300.0	2.0	2,500.0		
2032	100.0	100.0	3.0	750.0		130.0
2033	150.0	1,000.0	3.0	2,038.0		
2034		200.0	28.0	140.0	6.0	
2035		500.0	5.0	725.0	15.0	300.0
2036	50.0	280.0	2.0	490.0	14.0	657.0
2037	50.0		1.0	175.0	9.0	128.0

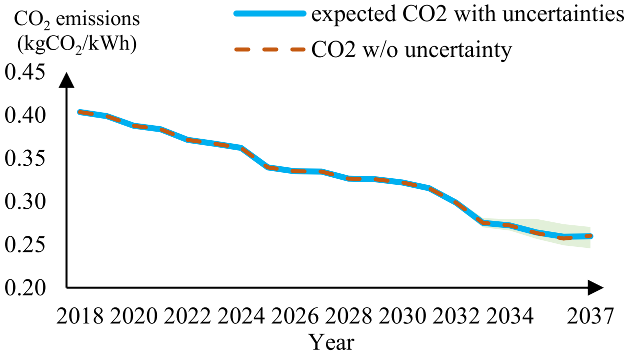

FIGURE 29. Comparison of CO_2 emissions of Case 3 with and without uncertainties.

64-bit Windows 11 PC with an i7-8750H CPU @2.20 GHz and 16 GB RAM. Linear programing was executed using MATLAB's "linprog" function. The computational time for a 20-year planning horizon of a single plan ranged from three to five minutes, depending on the number of additional units. This exceptional low computational cost enables the proposed GEP method to be used for investigating generation expansion plans with uncertainty.

VI. CONCLUSION

This paper presents a GEP method designed to integrate VRES and accommodate full-year hourly multiple load levels balance constraints. Building on the GEP method outlined in [15], which incorporates energy storage systems, renewable energy generation profiles, non-linear reliability constraint, and full-year hourly power balance constraints, this proposed method establishes a framework for developing a generation expansion plan that provides the necessary flexibility to address the intermittency caused by VRES and demand fluctuations. This framework eliminates the need to solve UC with the operational characteristics of generators, a task that often requires various approximation techniques due to its computational complexity. To handle multiple load levels balance constraints, this paper introduces a load classification method. This method categorizes the hourly load curve of the generation system into three levels – peak, intermediate, and base load – considering the system's generation mix and the characteristics of generation units. These load levels are then used in the multiple load levels balance constraints to ensure the generation system possesses adequate generation capacity corresponding to each load level. The proposed load classification and GEP methods are validated using Thailand's Power Development Plan 2018 revision 1 to demonstrate their applicability. Based on the load classification result, it is observed that the introduced load classification method can effectively distinguish between the impacts of increased system demand and increased VRES penetration. Consequently, it can accurately determine the required flexible capacity needed in the generation system. The planning results indicate that the proposed GEP method can provide the generation system with the necessary flexible units to cope with the intermittency of VRES. However, the applicability of the proposed GEP method may result in excessive investments during the transition from a conventional to a low-carbon generation system by introducing numerous fast-response units into an already established system. Therefore, this paper also proposes relaxing some constraints during the transition period. The result shows that the proposed relaxation can provide the generation system with adequate fast-response units while avoiding excessive early investments.

Due to its exceptionally low computational cost, the proposed GEP method is also suitable for addressing uncertainties. Planning for all possible scenarios can be performed within an acceptable computation time. Consequently, the

TABLE 14. Summary of conventional generation units (MW).retired and committed to be retired.

Year	Lignite	Bituminous	Natural Gas	Oil	Imported hydro	Biomass
2018	-560.0	-10.0	-346.0			
2019			-1,464.0	-5.0		
2020			-1,256.0			-8.0
2021		-10.0	-232.0			
2022			-712.0			
2023			-1,077.0			
2024	-540.0	-270.0	-360.0			-82.0
2025	-1080.0	-90.0	-2,880.0			-145.0
2026						-58.0
2027			-2,617.0			-56.0
2028			-1,289.0			-196.0
2029					-126.0	-179.0
2030						-103.0
2031						-63.0
2032		-1,347.0	-734.0			-83.0
2033			-2,134.0			-74.0
2034			-710.0	-315.0		-23.0
2035			-1,510.0		-948.0	-956.0
2036			-670.0			-3.0
2037		-660.0	-254.0			-22.0

expected value of any generation system index can be calculated based on the indices in each scenario and their respective probabilities.

While the proposed method allows for formulating generation expansion plans towards carbon neutrality or Net-Zero emissions, achieving such targets requires a radical transformation. This transformation involves adapting new power generation technologies or enhancing existing ones, such as through hydrogen fuel, Carbon Capture, Utilization and Storage (CCUS), new energy storage technologies, energy efficiency enhancement, demand response or virtual power plants. These options, and possibly others, should be considered in future work.

Nonetheless, the proposed method has limitations as it solely considers the generation system as a single area and neglects the transmission network. In practice, the generation system is often divided into regions or interconnected systems connected by major tie-lines. Additionally, each region may have its unique constraints, such as available fuel options, differing renewable energy resources, varying climate, distinct regional load profiles, and more. These constraints could affect the availability and characteristic of candidate generation units. Thus, they also need to be considered in the GEP. In future work, incorporating these constraints and methodologies into the GEP is of interest to make the generation expansion plan more realistic.

APPENDIX A EXISTING GENERATION SYSTEM AS OF DECEMBER 2017

See Tables 10 and 11.

APPENDIX B COMMITTED GENERATION UNIT

See Tables 12–14.

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