The impact of Variable Renewable Energy Integration on Total System Costs and Electricity Generation Revenue

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ABSTRACT Variable renewable energy (VRE) integration creates additional costs, called “integration costs.” These costs have grown with VRE penetration, potentially increasing the total system costs delivered to customers (direct integration costs) and decreasing electricity generation revenue, discouraging generators’ investment (indirect integration costs). Thus, integration costs can be an economic barrier to integrate high shares of VRE. This paper proposes a method to determine the impact of VRE integration on total system costs and electricity generation revenue. The method is a combination of the unit-commitment model, the optimal generation mix and optimal generation schedule analysis, and merit-order simulations. The results show that the total system costs are minimal at 70% VRE penetration. In addition, after 20% VRE penetration, the combination of solar and wind generation provided minimal total system costs rather than relying on wind or solar individually. Moreover, the profitability of generators from supplying energy to the energy market is declined by VRE penetration. Combined cycle gas turbines (CCGT), hydro, and wind generators face higher impacts on their electricity generation revenue than coal and solar generators. Electricity system planners and policymakers need to consider and prioritize the severity of VRE impacts on each technology grown with VRE penetration to enact consistent plans and policies.

INDEX TERMS Electricity market prices, Integration costs, Merit-order effect, Total system costs, Variable renewable energy

NOMENCLATURE

| SETS AND INDICES | PARAMETER |
|------------------|-----------|
| $d$              | $D_r(t)$  | Index of a considered day (workday or holiday) |
| $n$              | $Cr$     | Index of a generator unit |
| $r$              | $FOR$    | A considered day |
| $RD$             | $MC_n$   | Set of the representative days |
| $s$              | $N_{CCGT}$ | Index of a considered season (summer, rainy, or winter) |
| $t$              | $N_{Coal}$  | Index of a considered period (1$^{\text{st}}$ hour = 1, 2$^{\text{nd}}$ hour =2, …, 24$^{\text{th}}$ hour = 24) |

| PARAMETER |
|-----------|
| $C$       | Levelized capital cost of generator ($/\text{year/MW}$) |
| $Cr$      | Capacity credit (% of MW$_{\text{installed}}$) |
| $D_{\text{peak}}$ | Peak demand of the considered year (MW) |
| $D_r(t)$  | Electricity demand of the considered day $r$ at time $t$ (MW) |
| $FOR$     | Forced outage rate (% of MW$_{\text{installed}}$) |
| $MC_n$    | Marginal cost of $n$ ($/\text{MWh}$) |
| $N_{CCGT}$ | The number of CCGT generator units in the system |
| $N_{Coal}$ | The number of coal generator units in the system |
| $N_{d,s}$ | The number of the considered days in the considered season |
| $N_{Hydro}$ | The number of hydro generator units in the system |
| $N_{\text{Must-run}}$ | The number of must-run generators units in the system |

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Electricity generated from renewable energy (RE) is beginning to play an important role in electrical systems because of its use of free energy from nature and its environmental friendliness, as well as the rapid decrease in investment costs [1]. RE generation resources consist of both dispatchable RE, e.g., hydro, and non-dispatchable RE, which is generally called variable renewable energy (VRE), i.e., solar and wind. VRE comprises a substantial proportion of RE targets in many countries, including Thailand [2, 3].

In conventional generation-based systems, electrical system planners have always had to deal with variability and uncertainty to some extent, from both technical and economic perspectives. However, when VRE is integrated, it poses distinct challenges, significantly affecting total system costs (total costs of electricity generation and transmission) and electricity generation revenue [4-11]. Total system costs are eventually delivered to customers, whereas electricity generation revenue is important for attracting generators’ investment. Proactive electrical system planners and policymakers must address these challenges to ensure that their VRE plans, and policies can minimize costs to customers and must properly evaluate the effects on generators in order to enact consistent policies.

The costs of supplying electricity include the capital costs (CCs) of generation and transmission systems, fuel costs, and operating costs. Moreover, integrating any kind of generator into electrical systems contributes to additional costs, known as integration costs. These costs occur because of interactions between the integrated generators and the established electrical systems [12, 13]. These interactions consist of both technical aspects, i.e., satisfying system constraints, and economic aspects, i.e., changes in electricity market activities. However, integrating VRE generators creates more remarkable integration costs than conventional generators, and the costs grow with VRE penetration for several reasons.

First, VRE supply is variable, unpredictable, and location-specific, requiring sophisticated system planning and operation. Second, in energy markets, VRE is generally prioritized to supply electricity because of its low variable costs, but it often supplies electricity uncorrelated with demand because of its non-dispatchable characteristics. The VRE prioritizing decreases conventional generator utilization, whereas the uncorrelation between VRE generation and demand makes VRE possibly be curtailed to maintain system constraints. When generation is lower than intended, it can be considered as increased cost/MWh or decreased electricity generation revenue. In addition, during windy or sunny hours, marginal prices (MPs) can be very low. This circumstance is called the “merit-order effect.” Any generators participating in energy markets gain revenue based on MPs, and thus merit-order effects contribute to reductions in generators’ revenue. This means that the generated electricity has less market value when VRE penetration is extended [6-23].

In 2015, the estimated integration costs of Germany’s electrical systems, with a wind market share of 30–40%, were 29–41 $/MWh. These costs increase generation costs by 35–50% [12]. Integration costs occurred from electricity generation and transmission are direct integration costs, whereas those from the reduction of electricity generation revenue are indirect integration costs. Many studies have confirmed that indirect integration costs constitute the largest proportion of integration costs [7, 12, 17-19].

Undoubtedly, integration costs eventually have economic impacts on electrical system participants. First, integration costs increase the average electricity price for customers even...
though VRE is free energy from nature. This is because VRE is the cheapest resource in terms of marginal costs (MCs), not in terms of total system costs [24, 25]. Second, integration costs decrease the attractiveness of electricity generation investment because they reduce generators’ revenue and could make the generators are probably unable to recover their CCs, yet such investment is needed to ensure supply security and system flexibility [19, 25, 26]. Even though some of the CCs might be recovered through capacity mechanisms, ancillary service markets, or government subsidies, the costs indirectly affect customers [19, 27-29]. Thus, integration costs that increase in tandem with VRE penetration can form an economic barrier to integrating high shares of VRE [22]. These costs are important for system planning and policymaking. Ignoring or underestimating them leads to biased conclusions about the welfare-optimal generation mix, system transformation costs, and unintended outcomes of the implied policy [4, 12, 13, 30].

In terms of assessing the impact of VRE integration, system planners and policymakers must focus on overall costs to determine an optimal system plan and policy options that consider cost structures, minimize the burdens on customers and evaluate the effects on generators that provide supply security [24, 31-34]. For this purpose, the “total system cost approach” is appropriate. The total system cost approach can establish the optimal generation mix to meet the electricity demand at the lowest costs [5, 7]. Existing studies have included total system costs in their models to determine VRE integration impacts. Research [25] has found that an additional 0.38 c/kWh is required to reach a 50% share of RE in the Mexican electrical system. Another research has found that the 2030 RE target of California will increase total system costs by 15% compared to 2016 [35]. Further research has pointed out that costs increase from 0.031 $/kWh at 15% RE share to 0.047 $/kWh at 45% RE share [36]. Research [37] proposed an optimization method for Thailand’s energy planning. The results showed the difference in generation mix resulting from the various uncertainty scenarios and energy policy priorities. Nevertheless, these studies mainly focused on technical costs, such as capital, O&M, variable, and some aspects of direct integration costs. Indirect integration costs were not highlighted in these studies. Indirect integration costs were mentioned in [38, 39]. Research [38] provided a coordinated planning and operation model of renewable energy sources and energy storage systems. The amount of wind energy utilization and curtailment were considered. However, this research did not focus on the impacts of wind integration on conventional generators. In addition, the study was implemented on test systems, not real-world systems. Research [39] evaluated the impacts of wind penetration on electricity prices and the fixed cost recovery of conventional generators. Nonetheless, research [38, 39] did not consider the impact of solar integration, which also plays an important role in many countries’ electrical systems.

A. CONTRIBUTIONS

The main contributions of this paper can be summarized as follow:

1) The optimal generation mix and the optimal generation schedule for the specified VRE penetration level are proposed by using a techno-economic model. The model was aimed to minimize total system costs with a consideration of system constraints. The impact of both wind and solar integration, and key patterns in daily and seasonal variation were considered, which can reveal the alignment between VRE generation and demand, making the model comprehensive and accurate.

2) The impact of VRE integration on total system costs and electricity generation revenue were highlighted. The direct and indirect integration costs were pointed out. This paper provides precedence to the impact of VRE integration on both VRE and conventional generators.

3) Suggestions for electrical system planners and policymakers are provided to enact consistent plans and policies in consideration of the impact of VRE, in both the systems’ technical and economic perspectives.

The method assumed electrical systems with a liberalized structure. In the model, the unit commitment problem (UCP) was applied and resolved by mixed-integer linear programming (MILP), which is a MATLAB optimization tool. Integration costs were calculated by analyzing the optimal generation mix and the optimal generation schedule from the UCP and by using merit-order simulations.

B. PAPER ORGANIZATION

The remainder of the paper presents background knowledge about integration costs and assessment of the VRE integration’s impacts (Sections II and III, respectively). Section IV discusses the proposed methodology, whereas Section V outlines the data and assumptions used in the model. Section VI presents the results and discussion, and the conclusion of this paper is provided in Section VII.

II. INTEGRATION COSTS

Integration costs are caused by interactions between integrated generators and established electrical systems [12, 13]. These interactions consist of both technical aspects, i.e., maintaining system constraints, and economic aspects, i.e., changes in electricity market activities. Integrating either conventional or RE generators into electrical systems contributes to integration costs. However, VRE generators cause more remarkable integration costs than other generators because their characteristics are different. For example, VRE is non-synchronous as the electricity it generates fluctuates and can be accurately predicted only a few hours or days ahead. VRE generators can also be deployed in a much more distributed form than conventional generators. Moreover, the best areas to capture wind and sunlight are frequently located at a distance from load centers [14]. VRE is thus variable, unpredictable, and location-
specific [12, 13, 15]. To clarify, this paper categorized integration costs as direct integration costs and indirect integration costs.

**A. DIRECT INTEGRATION COSTS**

Direct integration costs stem from electricity generation and transmission, i.e., balancing costs, grid costs, and profile costs from flexibility effects.

---Balancing costs: VRE unpredictability creates system stability issues. In the event of forecast errors or unplanned conditions, conventional generators must provide balancing services, such as frequency regulation, to maintain system stability, which increases operating costs. To be clear, if VRE could be forecasted precisely, balancing costs would be zero [9].

---Grid costs: VRE generation can occur far from load centers, necessitating appropriate transmission systems and operation. Grid costs consist of voltage stability costs, transmission congestion, loss in transmission lines, and transmission expansion [12, 40].

---Profile costs incurred by “flexibility effects” (flexibility costs): VRE variability requires system flexibility [4, 19]. Conventional generators are forced to operate at non-optimal points to provide system flexibility, such as frequent startup and shutdown to compensate for variations in VRE generation (profile costs count only scheduled operations; unscheduled operations from forecast errors are counted as balancing costs) [12].

**B. INDIRECT INTEGRATION COSTS**

Indirect integration costs originate from the reduction of revenue from electricity generation, not from electricity generation or the transmission system itself, i.e., profile costs from utilization effects.

---Profile costs incurred by “utilization effects” (utilization costs): VRE variability requires firm capacity [4, 19]. However, VRE causes inefficient utilization of both conventional and VRE generation. In energy markets, VRE contributes to distinct market characteristics not seen in conventionally based systems for the following reasons.

First, VRE is generally prioritized to supply electricity because of its low variable costs. The energy supplied by conventional generators is reduced while their capacity is still needed to back up VRE sources. Thus, the capacity factors of conventional generators, e.g., combined cycle gas turbines (CCGTs), coal, and hydro, are decreased, as currently experienced in Germany [41]. Moreover, at high VRE penetration, VRE can be curtailed at light load times. When generation is lower than intended, it can be considered from two perspectives: either increased capital cost/MWh (specific capital cost) or reduced generators’ revenue from selling less electricity than their capability [12, 14, 17-19].

Second, VRE can supply electricity uncorrelated with demand because of its non-dispatchable characteristics. During particularly windy or sunny hours, the massive amount of energy supplied by VRE could flood the energy market with the low MCs energy. Moreover, the energy could highly exceed the demand. Therefore, the MPs in the circumstances could be very low (possibly zero or even negative), i.e., the “merit-order effect” [15, 19-21, 42]. It is important to consider these price variations [43] because any generators participating in energy markets gain their revenue based on MPs. Decreasing these prices will reduce the profitability of generators [20]. Thus, the merit-order effect reduces generators’ revenue, lowering the market value of generated electricity. Integration costs increase total system costs affecting customers. Moreover, these costs discourage generators’ investment in electrical systems with a liberalized structure because reduced MPs and energy supply potentially inhibit the recovery of their CCs [19, 20, 24, 25, 30, 44-46]. Even though some of the investment might be recovered through capacity mechanisms, ancillary service markets, or government subsidies, customers will be indirectly affected [6, 19, 20, 27-29, 47-49]. Fig. 1 illustrates the impacts and consequences of integration costs.

Integration costs grow with VRE integration because the greater the VRE penetration, the more difficult and uneconomic the operation and the larger the decrease in MPs [6, 12, 14-20]. Many studies have confirmed that profile costs, especially costs from utilization effects, are the largest component of integration costs [7, 12, 17-19]. These costs comprise the core notion of system effects [19].

**III. ASSESSMENT OF THE VRE INTEGRATION’S IMPACTS**

The impacts of VRE integration have been confirmed in many studies, as reviewed above. Electrical system planners and policymakers should assess both technical and economic aspects of the systems before setting system plans and policies. In monopolized markets, such assessments are done by utilities to guide investments in systems. In liberalized markets, assessments are important for making rules and regulations to incentivize investments that align with policy goals [4, 10].

The total system cost approach is appropriate for evaluating all costs and effects from VRE integration that occur in systems constituting mixed types of generators. Society must bear the total system costs, and thus the total system cost approach accounts for the various characteristics of generators and creates the lowest-cost generation mix of available resources. The approach considers both technical aspects, i.e., satisfying electrical system constraints and generation characteristic constraints, and economic aspects, i.e., minimizing total system costs [4-7, 50]. Complex computer models (or combinations of models) are used to simulate dispatch and capacity expansion and to assess the combination of resources that will best minimize total system costs [6].
The UCP is frequently used to set the models [12, 17, 18, 51, 52]. According to [53], the UCP pertains to deciding which generator units must be committed/de-committed up to a planning horizon, which lasts from one day to two weeks and is generally split into one-hour periods.

Mixed-integer programming (MIP) is generally used to solve the UCP. MIP is appropriate for coping with electrical system constraints, such as reserve requirements and ramping constraints along with generator unit variables that are integers i.e., initial conditions. MILP can also be used if non-convexity constraints are simplified to a piecewise linear function [53, 54]. In consonance with research [55], one of the potential key issues in the quality of electricity system modeling results is the ability of the models to cope with the dynamics of electricity demand and VRE. Three approaches are differentiated by the planning timeframe, i.e., the large block of time (integral approach), the representative days (semi-dynamic approach), and the very high time resolution (fully dynamic approach).

In electrical systems with a vertical structure, policymakers can allocate all total system costs within their overall rate structure. The generators can then gain their revenue at fixed rates [24]. However, in electrical systems with a liberalized structure, generators gain their revenue through electricity markets. System planners and policymakers must properly evaluate VRE impacts on electricity generation revenue affecting the attractiveness of investments for generators, which are indirect integration costs, as mentioned above. Although generators might make profits from other markets [47-49] or use market power to gain more revenue [39], the supports from policies can encourage investment and can cause resilience to the financing difficulties. According to [21], the reductions in supplied energy can be determined by considering the generation mix and the generation schedule. Reductions in MPs because of merit-order effects can be illustrated based on two main approaches: first, the development of electricity market models that simulate the operation of an energy market and calculate the resulting MPs for various scenarios; second, the regression analysis approach, which uses historical prices and generation data to quantify actual reductions in MPs for a given period. Both approaches were combined in some studies.

**IV. PROPOSED METHODOLOGY**

This paper proposes a method to determine the impact of VRE integration on total system costs and electricity generation revenue. The method consists of two main parts.

The first part involves minimizing total system costs at a specified VRE penetration level, considering system constraints, by using a unit commitment-based model (Section IV-A). The minimized total system costs at the specified penetration level are derived together with the optimal generation mix and the optimal generation schedule. After that, direct integration costs can be highlighted.

![Diagram showing Technical Impacts and Economical Impacts with Integration Costs and Consequences](https://example.com/diagram.png)

**FIGURE 1.** The impacts and consequences of integration costs.
The second part involves calculating indirect integration costs by analyzing the optimal generation mix and the optimal generation schedule and by using merit-order simulation (Section IV-B).

The semi-dynamic approach was used in this paper to capture the electricity supply and demand dynamics. The approach selected representative days to represent power variations during the considered year instead of using all days in a year. As mentioned by [55], this approach offers a compromise between having some dynamics and, at the same time, requiring less data and lower processing intensity for the calculating tools. The representative days were selected to capture key patterns in daily and seasonal variation, which can better reveal the alignment between VRE generation and demand, making the model more accurate [4].

The VRE penetration level was varied from 0 to 100% of electricity power demand to determine the relations between VRE penetration, total system costs, and electricity generation revenue. VRE resources consisted of solar and wind. The VRE generators’ technical impacts on the electrical system were maintained by conventional generators, which have considerable mechanical inertia, consisting of hydro generators and thermal generators, i.e., CCGT and coal combustion generators [4, 56].

A. MINIMIZING TOTAL SYSTEM COSTS USING A UNIT-COMMITMENT MODEL

Total system costs, which are incurred from generating electricity, must be minimized to deliver the least cost to customers. The objective function was to minimize total system costs in a considered year at a specified VRE penetration level, as shown in (1). Total system costs consist of levelized capital costs (CC), variable costs (VC), and direct integration costs. This paper focused on profit costs because they comprise the highest proportion of integration costs. Thus, only flexibility costs (FC) were included. Utilization costs (UC), which are indirect integration costs, were not included in the optimization. If the costs were included, then all the reductions in generators’ revenue would become burdens on the customers. The unit $/MWh was applied for ease of analysis; thus, the total system costs were divided by the total energy supplied for the considered year (E_annual).

\[
\text{Min} \left\{ \frac{VC_{\text{Annual}} + FC_{\text{Annual}} + CC_{\text{Annual}}}{E_{\text{Annual}}} \right\} \tag{1}
\]

The objective function was formed based on the daily unit-commitment, at a resolution of one hour, of the representative workdays and holidays from three different seasons (summer, rainy, and winter). The VC and FC of each generator unit (n) within a considered period (t) were different depending on its committed power at the time. All generators’ units have VC, whereas only thermal units, i.e., CCGTs and coal, have FC. This is because FC occur from turning boilers, steam lines, turbines, and auxiliary components on and off, actions that undergo unavoidably large thermal and pressure stress and thus only occur to thermal generators [57]. VC_{Annual} ($/year) and FC_{Annual} ($/year) were determined by the unit-commitment results of the representative workdays and holidays in all seasons. In the daily unit-commitment, VC of n at time t was calculated from the generator’s marginal cost (MC) multiplied by its energy output at time t (E_n(t)), and FC of n at time t was calculated by the multiplication of the startup status of n at time t (S_n(t)), which is a binary variable, and the startup cost of n (SC). The summation of the VC and FC throughout the daily unit-commitment horizon (T) were the VC and FC of a considered day (\text{rd}), then the VC and FC were multiplied by the number of the days in the considered season (N_{d,s}). After that, VC_{Annual} and FC_{Annual} were the summation of the VC and FC of all representative days (RD), as shown in (2) and (3), respectively.

\[
VC_{\text{Annual}} = \sum_{rd \in RD} \left( \sum_{t \in T} \left( \sum_{n \in N} MC_n \times E_n(t) \right) \times N_{d,s} \right)
\tag{2}
\]

\[
FC_{\text{Annual}} = \sum_{rd \in RD} \left( \sum_{t \in T} \left( \sum_{n \in N} SC_n \times S_n(t) \right) \times N_{d,s} \right)
\tag{3}
\]

For CCs, the costs depend on the installed capacity of generators, as shown in (4). CC_{Annual} ($/year) is the summation of CCs of VRE, hydro, and thermal generators. C are the levelized capital cost of the generator ($/year/MW). ICAP is the installed capacity (MW) needed to provide the firm capacity (MW) to the electrical system. Note that if the hydro generation is from hydro reservoirs that are also built for other purposes apart from electricity generation, such as irrigation, the CCs of the hydro generation in (4) only account for the electricity generation component, i.e., generators, not for the total costs of the reservoirs.

\[
CC_{\text{Annual}} = \left( C_{\text{CCGT \times ICAP_{CCGT}}} + C_{\text{Coal \times ICAP_{Coal}}} \right) + \left( C_{\text{Coal \times ICAP_{Coal}}} \right) + \left( C_{\text{Solar \times ICAP_{Solar}}} + C_{\text{Wind \times ICAP_{Wind}}} \right)
\tag{4}
\]

The objective function was optimized, subject to the system constraints: electrical system constraints and generation characteristic constraints. The electrical system constraints consist of procuring adequate planning reserve margin (PRM), electricity demand serving, and committing must-run units; For the PRM adequacy constraint, the total generators’ firm capacity (FCAP) must equal to or more than the system’s required PRM (PRM_{req}) and the peak demand of the considered year (D_{peak}), as shown in (5). The total FCAP can be calculated as shown in (6). The FCAP of VRE generators depends on its capacity credit (Cr), as shown in (7). The FCAP of thermal generators is their unforced capacity calculated from their forced outage rate (FOR)[4, 58]. This method used the average FOR of all generator units to calculate the unforced capacity of the generators, as shown in (8). If the average FOR is high, the unforced capacity
would be low contributing to low FCAP of the generators. For hydro generators and very small generators with bilateral contracts, their FCAP were considered equal to their dependable capacity and installed capacity, respectively. The total ICAP of solar and wind generators needs to be equal to or less than the considered VRE penetration level \( (L_{\text{VRE}}) \) as shown in (9). The ICAP of CCGT, coal, and hydro generators were the maximum of the total power output from all generators at time \( t \) throughout \( T \) as shown in (10)-(12).

\[
\text{Total FCAP} \geq (1 + \text{PRM}_{\text{req}}/100) \times D_{\text{peak}} \tag{5}
\]

\[
\text{Total FCAP} = \text{FCAP}_{\text{VRE}} + \text{FCAP}_{\text{Thermal}} + \text{FCAP}_{\text{bilateral}} \tag{6}
\]

\[
\text{FCAP}_{\text{VRE}} = (C_{\text{Solar}} \times ICAP_{\text{Solar}}) + (C_{\text{Wind}} \times ICAP_{\text{Wind}}) \tag{7}
\]

\[
\text{FCAP}_{\text{Thermal}} = ((1 - \text{FOR}_{\text{CCGT}}) \times ICAP_{\text{CCGT}}) + ((1 - \text{FOR}_{\text{Coal}}) \times ICAP_{\text{Coal}}) \tag{8}
\]

\[
\text{ICAP}_{\text{Solar}} + \text{ICAP}_{\text{Wind}} \leq L_{\text{VRE}} \times D_{\text{peak}} \tag{9}
\]

\[
\text{ICAP}_{\text{CCGT}} \geq \sum_{n} P_{n,\text{CCGT}}(t) \quad \forall t \in T, r \in \text{RD} \tag{10}
\]

\[
\text{ICAP}_{\text{Coal}} \geq \sum_{n} P_{n,\text{Coal}}(t) \quad \forall t \in T, r \in \text{RD} \tag{11}
\]

\[
\text{ICAP}_{\text{Hydro}} \geq \sum_{n} P_{n,\text{Hydro}}(t) \quad \forall t \in T, r \in \text{RD} \tag{12}
\]

The electricity demand serving constraint is that the total power output from all generators at time \( t \) must be equal to the electricity demand of the considered day at time \( t \) \( (D_{\text{t}}(t)) \), as shown in (13). Equation (14) shows the committing must-run units’ constraint where the summation of the online status of the must-run unit at time \( t \) \( (ON_{n \text{ must-run}}(t)) \) has to be equal to \( T \) which means the unit is operated all the time within the considered day. Note that, in this paper, each conventional generator can be dispatched independently, whereas the power and energy output from VRE were considered as the total power and energy output of all solar or wind generators in the system. Therefore, there is no index \( n \) for VRE generators. However, VRE generators can be curtailed to maintain the electrical system constraints.

\[
D_{\text{t}}(t) = \sum_{n,\text{CCGT}} N_{\text{CCGT}}(t) + \sum_{n,\text{Coal}} N_{\text{Coal}}(t) + \sum_{n,\text{Hydro}} N_{\text{Hydro}}(t) + P_{\text{Solar}}(t) + P_{\text{Wind}}(t) \quad \forall t \in T \tag{13}
\]

\[
T = \sum_{t=1}^{T} ON_{n \text{ must-run}}(t) \quad \forall n \in N_{\text{must-run}}, t \in T \tag{14}
\]

The generation characteristic constraints consist of relationship between operating status of a generator, minimum/maximum generation, ramp capability, and the limitations of hydro generators, which depend on the amount of water reserved in the considered year. Equation (15) shows the relationship between the online status of \( n \) at time \( t \) \( (ON_{n}(t)) \) and the startup status of \( n \) at time \( t \) \( (S_{n}(t)) \).

Equation (16) and (17) shows the minimum generation constraint and the maximum generation constraint. The constraint is involved by the relation of power output of \( n \) at time \( t \) \( (P_{n}(t)) \) and \( ON_{n}(t) \). Equation (18) and (19) shows the ramp-up and ramp-down capability constraints, respectively. The increased power output of \( n \) must be less than its ramp-up capability in 1 hour \( (R_{n,\text{up}}) \). The decreased power output of \( n \) must be less than its ramp-down capability in 1 hour \( (R_{n,\text{down}}) \). Note that \( R_{n,\text{up}} \) and \( R_{n,\text{down}} \) are constants. Equation (20) shows the constraint for the limitations of hydro generators which depend on the plant factor of \( n \) \( (PF_{n,s}) \), which is a constant calculated from the amount of water reserved in the considered season of the considered year. \( P_{\text{Solar}}(t) \) and \( P_{\text{Wind}}(t) \) must be equal to or less than the capability of VRE generation from the given sunlight or wind at the considered time \( (Pr(t)) \), multiplies with the ICAP as shown in (21) and (22).

\[
ON_{n}(t) - ON_{n}(t-1) \leq S_{n}(t) \quad \forall n \in N_{\text{Sys}}, t \in T \tag{15}
\]

\[
P_{n}(t) \geq P_{n}^{\text{min}} \times ON_{n}(t) \quad \forall n \in N_{\text{thermal}}, t \in T \tag{16}
\]

\[
P_{n}(t) \leq P_{n}^{\text{max}} \times ON_{n}(t) \quad \forall n \in N_{\text{thermal}}, t \in T \tag{17}
\]

\[
P_{n}(t) - P_{n}(t-1) \leq R_{n,\text{up}} \quad \forall n \in N_{\text{thermal}}, t \in T \tag{18}
\]

\[
P_{n}(t-1) - P_{n}(t) \leq R_{n,\text{down}} \quad \forall n \in N_{\text{thermal}}, t \in T \tag{19}
\]

\[
\sum_{n} P_{n,\text{Hydro}}(t) \leq P_{n,\text{Hydro}}^{\text{max}} \times PF_{n,s} \quad \forall n \in N_{\text{Hydro}} \tag{20}
\]

\[
P_{\text{Solar}}(t) \leq P_{\text{Solar}}(t) \times ICAP_{\text{Solar}} \quad \forall t \in T \tag{21}
\]

\[
P_{\text{Wind}}(t) \leq P_{\text{Wind}}(t) \times ICAP_{\text{Wind}} \quad \forall t \in T \tag{22}
\]

The UCP, which is a mixed-integer linear function, was solved by the MILP optimization tool “Intlinprog” in MATLAB.

**B. INDIRECT INTEGRATION COSTS CALCULATION**

In electrical systems with a liberalized structure, the reduction in supplied energy and MPs causes indirect integration costs that indicate the profitability of generators. In this section, the generation mix and generation schedule resulting from the optimization in Section IV-A were further analyzed, and the merit-order simulation of the energy market was performed to determine the indirect integration costs, i.e., the costs incurred by utilization effects (utilization costs). To clarify, this paper divides the costs into two categories: first, utilization costs from the reduction in supplied energy \( (UC_{E}) \); second, utilization costs from the reduction in the MPs \( (UC_{MP}) \). When VRE supplies energy to the system in energy markets, some generators must be removed from the market or reduce their output. However, any generator gains less revenue because of the reduction in the MPs. Thus, both \( UC_{E} \) and \( UC_{MP} \) can occur in a generator either separately or simultaneously. Fig. 2 shows the occurrence of utilization effects via the merit-order curve at a considered time. As shown in Fig. 2 (b), CCGT is taken out of the market. CCGT must reduce its generation level to prioritize the cheap energy from VRE.
Hydro, CCGT₁, and C₁-C₃ do not have to reduce their output because their electricity is still needed. If VRE is curtailed, it is considered a reduction in supplied energy as well. Thus, UCₑ only occurs to CCGT₂, CCGT₃, and VRE (if it is curtailed). However, each MWh from any generator receives less revenue because the MPs is reduced. Therefore, UCₘₚ occurs to every generator.

1) CALCULATION OF UTILIZATION COSTS FROM THE REDUCTION IN SUPPLIED ENERGY

UCₑ can occur to both VRE and conventional generators. For the VRE generators, UCₑ are caused by the curtailment of VRE generation. The costs are the difference between the CCs/energy of generators with and without curtailment. The calculations of UCₑ incurred on VRE generators are shown in (23) and (24), where E_utilized is the energy output of VRE generators after curtailment derived from the optimal generation schedule.

$$UC_{E_{\text{Solar}}} = \frac{C_{\text{Solar}} \times ICAP_{\text{Solar}}}{E_{\text{Utilized}}} - \frac{C_{\text{Solar}} \times ICAP_{\text{Solar}}}{\sum_{i=1}^{T} P_{S_i}(t)}$$

(23)

$$UC_{E_{\text{Wind}}} = \frac{C_{\text{Wind}} \times ICAP_{\text{Wind}}}{E_{\text{Utilized}}} - \frac{C_{\text{Wind}} \times ICAP_{\text{Wind}}}{\sum_{i=1}^{T} P_{W_i}(t)}$$

(24)

For conventional generators, UCₑ are caused by the reduction in the generators’ utilization. The costs are the difference between the CCs/energy of the generators with and without VRE integration. The calculations of UCₑ incurred on conventional and hydro generators are shown in (25)–(27). ICAP with VRE, ICAP without VRE, E with VRE, and E without VRE are the installed capacity and the energy output of the generators with and without VRE integration. The parameters are calculated from the optimal generation mix and optimal generation schedule at a specified VRE penetration level.

$$UC_{E_{\text{CCGT}}} = \frac{C_{\text{CCGT}} \times ICAP_{\text{CCGT}}}{E_{\text{with VRE}} - E_{\text{without VRE}}}$$

(25)

$$UC_{E_{\text{Coal}}} = \frac{C_{\text{Coal}} \times ICAP_{\text{Coal}}}{E_{\text{with VRE}} - E_{\text{without VRE}}}$$

(26)

$$UC_{E_{\text{Hydro}}} = \frac{C_{\text{Hydro}} \times ICAP_{\text{Hydro}}}{E_{\text{with VRE}} - E_{\text{without VRE}}}$$

(27)

2) CALCULATION OF UTILIZATION COSTS FROM THE REDUCTION IN MARGINAL PRICES

UCₘₚ are the difference between the MPs with and without VRE integration at time t (Δλ(t)) multiplied by the energy supplied by all generators at a specific time (Eₜₜ(t)), as shown in (28)–(30). The MPs at time t (λ(t)) in a VRE penetration level was derived by the merit-order simulation. The λ(t) is the function of the merit-order curve and Dᵣ(t), as shown in (31). This paper assumes that the electricity market (energy-only market) is the theoretically perfect competition for which generators will offer the lowest price they can accept without loss to ensure they can be committed to selling the energy [59]. Thus, the merit-order curve is set from the MC of each generator.

$$UC_{M_P}(t) = \Delta \lambda(t) \times E_{Total}(t)$$

(28)

$$\Delta \lambda(t) = \lambda_{\text{without RE}}(t) - \lambda_{\text{with RE}}(t)$$

(29)

$$E_{Total}(t) = E_{\text{CCGT}}(t) + E_{\text{Coal}}(t) + E_{\text{Hydro}}(t) + E_{\text{with VRE}}(t)$$

(30)

$$\lambda(t) = \text{Merit-order curve}(Dᵣ(t))$$

(31)

The inputs of the method are electricity demand profiles and VRE generation profiles of all representative days in RD, which depend on the seasons and days, capital and operating costs of conventional and VRE, VRE capacity credit, and the system constraint data. Lastly, a sensitivity analysis was conducted to determine the relations between total system costs and electricity generation revenue and VRE penetration. Fig. 3 shows the calculation diagram of the proposed methodology.
V. DATA AND ASSUMPTIONS

This paper used Thailand’s electrical system as the test system. Although the system is vertically structured, this paper assumed that it was liberalized. The considered year was 2022. The electricity demand profiles of both workdays and holidays, as well as VRE generation profiles, are shown in Fig. 4–Fig. 7, which are approximated data from the Electricity Generating Authority of Thailand (EGAT). The system has 18 hydropower plants, 18 combined cycle power plants, and eight coal power plants. This paper considered the power plants’ lifetime of 20 years. The $PRM_{req}$ is 15% of the peak demand of the considered year [18]. The characteristics of each power plant are different depending on the individual configuration. Table I shows a summary of the characteristics, which are approximated data from EGAT. The generation capital costs and operating costs, i.e., variable costs and startup costs, are shown in Table II. Fig. 8 shows the average capacity credits of VRE collected from the literature [60-63].
This is because no matter how many VRE generators are installed in the electrical system, the conventional generators’ installed capacity requirement barely decreases. VRE generators cannot independently satisfy system constraints because VRE generation is non-dispatchable and its capacity credit is too low, especially at high penetration. Thus, conventional generation is needed to compensate for VRE generation variability and to guarantee the adequacy of PRM.

At 10–70% VRE penetration, the total system costs are decreased because VRE reduces the variable costs (VCs) of the system by saving fossil fuel costs. At 80–100% VRE penetration, the total system costs are increased because the avoided VCs are lower than the CCs of conventional and VRE generators combined, and VRE is curtailed to maintain system constraints. Compared to VCs, the direct integration cost, i.e., flexibility costs (FCs), does not affect the total system costs and is hardly changed by VRE penetration.

Fig. 10 shows the optimal generation mix at a specific VRE penetration level. The important findings of this paper are that the total system costs are minimal at 70% VRE penetration. In addition, after 20% VRE penetration, the combination of solar and wind generation provided optimal generation mix minimizing the total system costs rather than relying on wind or solar individually.

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VI. RESULTS AND DISCUSSION

The proposed methodology was simulated to determine the impacts of VRE integration on total system costs and electricity generation revenue using the data from Section V. Over 10 study cases were simulated varying the VRE penetration level. The impacts of VRE on total system costs and electrical generation revenue are shown in Sections VI-A and VI-B, respectively.

A. THE IMPACTS OF VRE INTEGRATION ON TOTAL SYSTEM COSTS

Total system costs at a specific VRE penetration level were minimized by the method shown in Section IV-A. The relations between the total system costs and VRE penetration are shown in Fig. 9. The CCs of VRE increased by VRE penetration, whereas those of conventional generation were hardly changed by VRE penetration level.
B. THE IMPACTS OF VRE INTEGRATION ON ELECTRICITY GENERATION REVENUE

Minimizing total system costs provided the optimal generation mix and the optimal generation schedules of the generators, as mentioned in Section IV-A. These results were further analyzed to determine the utilization costs from the reduction in supplied energy \((U_C)\), and the merit-order simulation was used to determine the utilization costs from the reduction in MPs \((U_{MP})\), as mentioned in Section IV-B.

1) UTILIZATION COSTS FROM THE REDUCTION IN SUPPLIED ENERGY

\(U_C\) of conventional generator is relevant to the capacity factor (CF), whereas \(U_C\) of VRE generator is relevant to the percentage of VRE curtailment. That is because these factors describe the proportion of installed capacity and utilization of the generators. Fig. 11 (a) and (c) shows the CF of conventional generators and the VRE curtailment in relation with VRE penetration. These factors were calculated from the optimal generation mix and optimal generation schedules. The low CF of conventional generators and the high VRE curtailment, which are inefficient utilizations of the generators, are the causes of \(U_C\), as shown in Fig. 11 (b) and (d).

The results show that the CF of the flexibility generators, i.e., CCGTs, is decreased by VRE penetration because the CCGT generators’ capacity is necessary to satisfy system constraints, but they must supply less energy output than their capability because VRE generators are prioritized. For the baseload generators, i.e., coal, their CF are also decreased but still higher than those of CCGTs. Since the coal generators have lower VCs than CCGTs, they are always committed to supplying energy output more continuously than CCGTs. Thus, \(U_{C,\text{CCGT}}\) and \(U_{C,\text{Coal}}\) are increased in the same manner as the decreased CF.

The CF of hydro generation increases at low VRE penetration because hydro generation combined with VRE generation, which both involve low-cost generation, can supply energy to replace CCGTs. This makes \(U_{C,\text{Hydro}}\) negative. That means VRE integration involves the higher operation of hydro generators. However, the CF of hydro generators starts to decrease and decelerate after 30% VRE penetration. Thus, \(U_{C,\text{Hydro}}\) negatively increases.

For VRE generators, curtailment occurs after 50% VRE penetration. Wind curtailment is higher than solar curtailment because wind generation tends to supply output throughout the day, especially from midnight to dawn, whereas solar generators’ output is intense during the daytime. This makes the probability of wind being curtailed is higher than solar. \(U_{E,\text{Solar}}\) and \(U_{E,\text{Wind}}\) are increased in relation to increased curtailment.

The variability of the CF, VRE curtailment, and \(U_C\) shown in Fig. 11 can be explained as follows. At low VRE penetration, CCGT and coal generators need to reduce their output because VRE generators are prioritized. Hydro generators can cooperate with VRE because of their high flexibility and low VCs. Thus, some CCGT's can be shut down, but their installed capacity still are needed for being reserve margin.

![Graphs showing the impact of VRE integration](image)

**FIGURE 11.** (a) the capacity factor (CF) of conventional generators; (b) \(U_C\) incurred on conventional generators; (c) the curtailment of VRE generators; (d) \(U_C\) incurred on VRE generators.
After 30% VRE penetration, where wind generators participate in the system, the combination of wind and solar can serve baseload and start to replace coal generators.

At high VRE penetration, VRE becomes the main generation supply, hydro and CCGTs supply output only when VRE variability compensation is needed. Coal generators need to reduce the output rapidly at 50-100% because the combination of VRE and hydro/CCGTs, which have more flexibility, can serve baseload. After 50% VRE penetration, VRE must be curtailed at light load time, especially on the holidays in winter. Otherwise, electricity generation and demand would be unbalanced.

2) UTILIZATION COSTS FROM THE REDUCTION IN MARGINAL PRICES

The MPs of every considered period was evaluated to determine the utilization costs from the reduction in MPs ($/MWh). Fig. 12 shows the relations between the average hourly MPs among all study cases and VRE penetration. The MPs was significantly reduced when VRE penetration was more than 40%. The MPs was mostly reduced in the daytime when the generated electricity from solar combined with wind served most of the electricity demand. In the test system, CCGT generators had the highest MC, and thus the MPs when VRE supplied low electricity was equal to the CCGTs’ MC, which was around 53 $/MWh. However, if there are gas turbines or other generators that have a higher MC than that of CCGTs participating in the energy market, the graph would fluctuate more, and the MPs would be high at peak load and low VRE time.

Fig. 13 shows the relations between $/MWh and VRE penetration. The costs were calculated from the difference between the MPs with and without VRE integration at a specific time.

The costs from utilization effects, which are indirect integration costs, affect electricity generation revenue. Fig. 14 shows the costs of generators compared with the MPs they gain from the energy market. If the MPs ($/MWh) is higher than the costs of generating electricity ($/MWh), electricity generation is profitable. For all generators, their costs consist of CCs and VC, whereas FC are neglected because they constitute a very small proportion, as shown in Fig. 9. $U_{CE}$ are considered as increasing in specific capital costs. $U_{CMP}$ show their effects through the reduction in prices. From Fig. 14, CCGT and hydro generators cannot recover their costs by the MPs they gain even when there is no VRE penetration. If VRE is integrated, indirect integration costs would cause them worse unprofitable. CCGT and hydro generators need to recover the remaining costs from other markets. Coal generators face fewer effects than CCGTs, and the generators are unprofitable if VRE is integrated by more than 70% of electricity demand. Wind generators are unprofitable if VRE is integrated by more than 60%. Solar generators are profitable at every VRE penetration level, but the profit is decreased by VRE penetration. $U_{CE,CCGT}$ is high compared to $U_{CE}$ of other conventional generators even at low VRE penetration. $U_{CE,Solar}$ and $U_{CE,Wind}$ are low compared to $U_{CE}$ of conventional generators.

All the results from Sections VI-A and VI-B show that integrating a high share of VRE into the system causes high total system costs and inefficient utilization of generators especially, with conventional generators contributing greatly to indirect integration costs. These consequences can in turn increase electricity prices and discourage generators’ investment. To determine VRE-related plans and policies, electrical system planners and policymakers must consider these consequences. If the generators are unable to recover their costs through energy markets, then ancillary service markets, capacity mechanisms, and additional subsidies are needed to boost investment attractiveness. Plans and policies should consider prioritizing the severity of indirect integration costs on each technology grown with VRE penetration. For example, if system planners and policymakers need to increase VRE penetration up to 70% where the total system costs are the lowest, coal generators, which are base-load generators, and solar generators are not expected to encounter significant impacts from indirect integration costs. Support schemes for coal and solar generators might not be essentially required. The policymakers must consider schemes that will remediate the severe indirect integration costs incurred to CCGT, hydro, and wind generators.

![Figure 12](https://example.com/fig12.png)

**FIGURE 12.** Relations between the average hourly MPs and VRE penetration.

![Figure 13](https://example.com/fig13.png)

**FIGURE 13.** Relations between utilization costs from the reduction in the MPs and VRE penetration.
However, too much attractiveness boosting may sustain ultimately unnecessary generation technologies and slow the procurement of new technologies that are fully compatible with VRE, ultimately delaying the energy transition and raising its costs. The cost of support schemes is eventually paid by customers; thus, it should be minimized. The schemes might not need to compensate all indirect integration costs to the generators. The value provided by generators to the system should be considered to indicate how much the generators should be supported. The value dimension includes two components – power system value and additional social value, both dimensions are used to assess how much the generators are worthwhile [66]. In addition, it is important to note that conventional generators would find their additional value from ancillary service markets and capacity mechanisms for providing system services, whereas VRE generators would not be able to capitalize on other markets than energy markets. With these
schemes, if some types of generators have high costs but create low value to the system, they will be automatically phased out and replaced by lower costs and higher value types. Otherwise, the system might have to keep subsidizing some technologies for longer than expected, which pass on unnecessary burdens to the final customers.

Moreover, there are several ways to mitigate the impact of VRE integration that system planners and policymakers could consider. For example, distributing VRE across several regions could make VRE more reliable and less dependent on the weather condition in specific areas [67]. Electricity pricing strategies, such as the time of use (TOU), can be used to reduce peak demand and to improve power quality [68]. Bidding strategies also help in dealing with electricity market challenges [10, 23]. Flexibility resources can be used to provide system operation services rather than only relying on conventional generators [69]. With the mentioned ways, overinvestment in generators, inefficient generators’ utilization, and electricity market challenges would be reduced contributing to the less impact of VRE integration on total system costs and electricity generation revenue.

VII. CONCLUSION

The VRE integration costs increased by VRE penetration can possibly become an economic barrier to developing VRE at high shares by increasing total system costs and discouraging generators’ investment. This paper proposed a method to determine the impacts of VRE integration on total system costs and electricity generation revenue. The total system costs were minimized based on the unit commitment-based model solved by MILP, after which the impacts on electricity generation revenue were evaluated by analyzing the optimization results and using the merit-order simulation. This paper used Thailand’s electrical system as the test system assuming that it was a liberal structure. The considered year was 2022. The results showed that the total system costs are minimal at 70% VRE penetration. In addition, after 20% VRE penetration, the combination of solar and wind generation provided optimal generation mix minimizing the total system costs rather than relying on wind or solar individually. Moreover, the profitability of all generators from supplying energy to the market is declined by VRE penetration. CCGT and hydro generators cannot recover their costs by the MPVs they gain even when there is no VRE penetration. If VRE is integrated, indirect integration costs would cause them worse unprofitable. Coal generators face fewer effects than CCGTs, and the generators are unprofitable if VRE is integrated by more than 70% of electricity demand. For VRE, wind generators are unprofitable if VRE is integrated by more than 60%. Solar generators are profitable at every VRE penetration level, but the profit is decreased by VRE penetration. Support schemes for generators may be needed considering and prioritizing the severity of indirect integration costs on each technology grown with VRE penetration. However, the cost of support schemes is eventually paid by customers, policymakers should trade-off between the cost of support schemes and the value provided by generators to the system to prevent passing on unnecessary burdens to the final customers. Moreover, system planners and policymakers should consider measures to mitigate the impact of VRE integration on total system costs and electricity generation revenue.

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