Impact analysis of variable renewable energy integration on total system costs and electricity generation revenue and impact mitigation

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การวิเคราะห์ผลกระทบของระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรต่อต้นทุนโดยรวมของระบบไฟฟ้าและรายได้จากการผลิตไฟฟ้า และการบรรเทาผลกระทบ

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วีรยา อิ่มเจริญกุล : การวิเคราะห์ผลกระทบของระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรต่อต้นทุนโดยรวมของระบบไฟฟ้าและรายได้จากการผลิตไฟฟ้า และการบรรเทาผลกระทบ. (Impact analysis of variable renewable energy integration on total system costs and electricity generation revenue and impact mitigation) อ.ที่ปรึกษาหลัก : รศ. ดร.สุรชัย ชัยทัศนีย์

การเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรเข้าสู่ระบบไฟฟ้าทำให้เกิดค่าใช้จ่ายเพิ่มเติม เรียกว่า *ต้นทุนการบูรณาการ* ค่าใช้จ่ายเหล่านี้เพิ่มขึ้นตามปริมาณระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรที่มีในระบบไฟฟ้า ซึ่งอาจทำให้ต้นทุนรวมของระบบที่จะถูกส่งต่อไปยังลูกค้า (ต้นทุนการบูรณาการโดยตรง) สูงขึ้น และลดรายได้จากการผลิตไฟฟ้า ทำให้ลดความน่าดึงดูดในการลงทุนผลิตไฟฟ้า (ต้นทุนการบูรณาการทางอ้อม) ดังนั้น ต้นทุนการบูรณาการอาจเป็นอุปสรรคทางเศรษฐศาสตร์ในการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปร วิทยานิพนธ์นี้มีวัตถุประสงค์หลักเพื่อเสนอวิธีการคำนวณผลกระทบของการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรต่อต้นทุนรวมของระบบและรายได้จากการผลิตไฟฟ้า วิธีที่นำเสนอนี้สามารถจัดหาแผนระบบไฟฟ้า สัดส่วนการผลิตไฟฟ้า และแนวทางการเดินเครื่องกำเนิดไฟฟ้าที่เหมาะสมที่สุดในกรณีศึกษาต่าง ๆ ได้ นอกจากวัตถุประสงค์หลักแล้ว วิทยานิพนธ์นี้ยังมีการนำเสนอการบรรเทาผลกระทบของการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปร โดยการเพิ่มความยืดหยุ่นของโรงไฟฟ้าและการใช้กลยุทธ์การเสนอราคาในตลาดไฟฟ้า ในการกำหนดแผนและนโยบายที่เกี่ยวข้องกับการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปร ผู้วางแผนระบบไฟฟ้าและผู้กำหนดนโยบายจำเป็นต้องจัดลำดับความสำคัญของความรุนแรงของต้นทุนการบูรณาการที่ส่งผลต่อการผลิตไฟฟ้าแต่ละประเภทซึ่งจะเพิ่มขึ้นตามปริมาณการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปร ตลาดพลังงานและกลไกการซื้อกำลังการผลิตมีความสำคัญต่อความคุ้มค่าในการลงทุนการผลิตไฟฟ้า นอกจากนี้ยังมีวิธีในการลดผลกระทบของการเชื่อมต่อระบบผลิตไฟฟ้าพลังงานหมุนเวียนผันแปรที่ผู้วางแผนระบบและผู้กำหนดนโยบายสามารถดำเนินการได้ เช่น การเพิ่มความยืดหยุ่นให้กับระบบไฟฟ้าที่จะสามารถลดต้นทุนรวมของระบบได้ นอกจากนี้กลยุทธ์การเสนอราคายังช่วยในการลดผลกระทบที่เกิดขึ้นกับรายได้ของผู้ผลิตไฟฟ้าได้อีกด้วย

สาขาวิชา	วิศวกรรมไฟฟ้า	ลายมือชื่อนิสิต	....
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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 investment by generators (indirect integration costs). Thus, integration costs can serve as an economic barrier to the integration of high VRE shares. The main objective of this dissertation is to propose a novel method of determining the impacts of VRE integration on total system costs and electricity generation revenue. With this method, the optimal generation mix and optimal generation schedules at the specific VRE penetration level in different study cases were provided. The impacts of VRE integration on total system costs and electricity generation revenue were highlighted, alongside the direct and indirect integration costs. Moreover, the profitability of electricity generation was evaluated. Aside from its main objective, this dissertation more comprehensively includes assessments of VRE impact mitigation through enhancing the flexibility of existing power plants and the use of a bidding strategy. To determine VRE-relevant plans and policies, electrical system planners and policymakers must prioritize the severity of integration costs grown with VRE penetration, which impacts total system costs and electricity generation revenue. Both energy markets and capacity mechanisms are crucial for the profitability of generators. Moreover, system planners and policymakers could consider several ways to mitigate the impact of VRE integration. For one, enhancing system flexibility decreases the total system cost. Second, bidding strategies could also help generators manage energy market challenges.

Field of Study:	Electrical Engineering	Student's Signature ....
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Chapter 1
Introduction

This chapter presents the problem statement that identifies an overview of the impacts of variable renewable energy (VRE) on total system costs and electricity generation revenue and the importance of considering these impacts in electrical system planning and policymaking. The objectives of the dissertation are also stated. In addition, the scope of work, the step of the study, the expected benefits, the literature reviews, and the dissertation structure are provided.

1.1 Problem Statement

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, generally called Variable Renewable Energy (VRE), i.e., solar and wind. VRE is 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, while 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 plans and 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 planning constraints (SPCs) and system operational constraints (SOCs), 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 and high-cost system operations. The greater the VRE penetration, the more difficult and expensive the 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. Therefore, marginal prices (MPs) can be very low during windy or sunny hours. This circumstance is called the "merit-order effect (MOE)." Any generators participating in energy markets gain revenue based on Marginal prices; thus, MOE contributes to reductions in generators' revenue. The greater the VRE penetration, the greater the drop in prices. This means 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 30–40% wind market share, were 29–41 $/MWh. These costs increase generation costs by 35–50% [12].

VRE characteristics create high integration costs. Thus, many studies have categorized these costs into three terms differentiated by their effects on electrical system interactions. First, the effects of VRE unpredictability are called "balancing costs." Second, the effects of locations are called "grid costs." Third, the effects of variability are called "profile costs," which consist of the costs of providing flexibility to electrical systems (flexibility effects) and the costs of inefficient utilization of generators (utilization effects). Balancing, grid, and profile costs from flexibility effects are direct integration costs because they occur from electricity generation and transmission. In contrast, profile costs from utilization effects are indirect integration costs because they occur from the reduction of electricity generation revenue, not from electricity generation or transmission itself. Many studies have confirmed that profile costs, particularly those from utilization effects, constitute the most significant 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 regarding marginal costs, not total system costs [24, 25]. Second, integration costs decrease the attractiveness of electricity generation investment because they reduce generators' revenue from energy markets and could make the generators probably unable to recover their capital costs, yet such investment is needed to ensure supply security [19, 25, 26]. Even though some of the capital costs 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]. Methods for VRE integration that integrate all costs and derived effects are needed [24, 31-34]. These methods need to consider cost structures, minimize customer burdens, and evaluate the impact on generators that provide supply security.

Moreover, the impacts of VRE can be mitigated by enhancing the flexibility of existing power plants. As claimed by [35], less flexible electrical systems can be more expensive to operate, as they force more expensive units to stay on when less expensive ones could be used to meet the demand. While flexibility has always been a necessary component of electrical systems, given the uncertainty of demand and conventional generation outages, the growth in VRE increases the need for flexible resources. Research [35] evaluated the impact of reducing the minimum generation level of the coal generation fleet from 60% to 40% of nameplate capacity and observed the corresponding decrease in production costs. At low VRE penetration, this increased flexibility provides minimal benefit. However, at higher levels of VRE penetration, increased flexibility results in decreased curtailments, reducing fuel consumption and decreasing the system production cost. Thus, total system costs could be reduced, and electricity generation revenue could be increased by enhancing the flexibility of existing power plants.

In addition, the impacts of VRE on electricity generation revenue can be mitigated by generators' bidding strategy. One of the strategic goals is withholding electricity generation with low marginal costs from the energy market to increase the MPs when the prices are low. VRE generators might curtail their output following their strategic aim to maximize market profits [36-38]. However, VRE curtailment can be problematic. Generating electricity at a level below their actual capability contributes to reductions in the generators' revenue from selling less electricity than their availability [12, 14, 17-19]. It also decreases their ability to recover their capital costs because of the reductions in output [39]. Therefore, the method that considers the trade-off between the amount of VRE output and the MPs will provide the maximum profits to the generators and could reduce the impacts of VRE on electricity generation revenue.

Given this context, this dissertation's main objective is to propose a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue. The method consists of two main parts. The first part is electrical system planning considering the impacts of VRE integration, the total system costs were minimized to find the optimal generation mix and the optimal generation schedule for the specified–VRE penetration level with consideration of SPCs and SOCs. The second part is generation revenue calculation. Generation revenue from energy markets and capacity markets, as well as the direct and indirect integration costs, were evaluated in this part. This dissertation focuses on the profile costs that are relevant to generation systems because they are the highest proportion of integration costs [7, 12, 17-19]. The method assumed electrical systems with liberalized structure. In the model, the generation mix optimization and the Unit Commitment Problem (UCP) were applied. The calculation were Linear Programming (LP), and Mixed Integer Linear Programming (MILP). They were solved optimization tools in MATLAB, "linprog" and "Intlinprog", respectively. For LP, the approach can simplify power allocation and determine the installation of generation technologies, while MILP is appropriate to cope with electrical systems operational constraints such as reserve requirement and ramping constraints along with generator unit variables that are integer such as initial conditions, incremental cost curves, minimum up- and down-times [40, 41]. Integration costs were calculated by analyzing the optimal generation mix and the optimal generation schedule from UCP and using energy market simulation. The generation revenue was evaluated by the energy market and capacity market simulation.

Aside from the main objective, this dissertation also proposes the VRE impact mitigation methods and assesses their outcome to make the study more comprehensive. The method to mitigate VRE impacts consists of two aspects. First is the system perspective by enhancing system flexibility. The second is the market perspective by using a bidding strategy. For the bidding strategy, the method finds the optimal VRE generation schedules to maximize the profits of VRE generators. The total profits of all VRE generators are maximized instead of those of individual generators to avoid sub-optimal results. The method considers the optimization among the amount of VRE output, the marginal prices, and the SOCs. The VRE support schemes involving prices VRE offered to the market are considered. The method combines the merit-order model, which is nonlinear, and the unit-commitment model, which is mix-integer and linear. The first model simulates the energy market's operation, and the second one satisfies the SOCs. The models were solved by MATLAB's optimization tools "Fmincon" and "Intlinprog", respectively.

The main contributions of this dissertation are as follows.

1. The optimal generation mix, and optimal generation schedules at the specific VRE penetration level in different study cases were provided. The method aimed to minimize total system costs considering system constraints. The impacts of both wind and solar integration and key patterns in daily and seasonal variation were considered, revealing the alignment between VRE generation and demand, making the model comprehensive and accurate.

2. Comprehensively understanding about impacts of VRE on electrical systems from both technical and economic perspectives was presented, along with the ways to mitigate the impacts.

3. VRE integration costs in terms of direct and indirect costs are defined to cope with them appropriately by consistent system planning and policymaking.

4. The impacts of VRE integration on total system costs and electricity generation revenue were highlighted. The direct and indirect integration costs were pointed out. The generation revenue from both the energy and capacity market were evaluated. This dissertation provides precedence to the impacts of VRE integration on both VRE and conventional generators.

5. Assessment of the VRE impact mitigation by enhancing system flexibility and using a bidding strategy was presented.

6. Suggestions for electrical system planners and policymakers are provided to enact consistent plans and policies considering the impact of VRE from both the systems' technical and economic perspectives.

1.2 Objective

The objectives of this dissertation are as follows.

1. To propose a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue.

2. To assess the VRE impacts mitigation by enhancing system flexibility and using the bidding strategy.

3. To guide electrical system planners and policymakers to make VRE plans and policies consistent with VRE penetration and integration costs.

1.3 Scope of Work

The scopes of work of this dissertation are listed below.

1. This dissertation proposed a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue, as well as the assessment of the VRE impact mitigation.

2. The semi-dynamic approach was used to capture the electricity supply and demand dynamics. The idea behind this approach is a compromise between having some dynamics and, at the same time requiring fewer data and lower processing intensity for the mid/long-term planning tools [42].

3. This dissertation focused on profile costs because they are the highest proportion of integration costs [7, 12, 17-19].

4. This dissertation used Thailand's electrical system as the test system. Although the system is a system with a vertical structure, this dissertation assumed it as a liberalized structure.

5. Regarding the impacts of VRE on electricity generation revenue, this dissertation focused on the energy market (day-ahead market) and the capacity market with the theoretically perfect competition.

6. Regarding enhancing system flexibility, this dissertation focus on retrofitting thermal power plants.

7. Regarding the bidding strategy to mitigate the VRE impact, this dissertation considered physical withholding.

1.4 Step of Study

The steps of the study of this dissertation can be summarized as follows.

1. Studying the relevant research work as follows.

1.1 Studying the VRE characteristics that lead to challenges in integrating VRE into electrical systems [43].

1.2 Studying the impacts of VRE on electrical system operations and planning [18, 43, 44].

1.3 Studying the impact of VRE on electricity generation revenue in terms of the inefficient power plant utilization [12, 14, 17-19, 25, 45]

1.4 Studying electricity market structures and the impact of VRE on electricity generation revenue in terms of the changes in electricity market activities [6, 7, 12-22, 45-49].

1.5 Studying the VRE support scheme focusing on the support provided to VRE generators and how the schemes involve prices that VRE generators offer to the markets [6, 36, 50-61].

1.6 Studying VRE integration costs [7, 9, 12-15, 17-19].

1.7 Studying system planning approach considering VRE impacts [18, 24, 31-34, 40, 41, 62-65], and how to evaluate impacts of VRE on electricity markets [15, 21, 24, 66, 67].

1.8 Studying the VRE impact mitigation from both the electrical systems' side [18, 35, 68, 69], i.e., enhancing the flexibility of existing power plants, and the markets' side, i.e., bidding strategies [36-39, 70-73].

2. Analyzing and identifying the problems as follows.

2.1 Identify and classify integration costs.

2.2 Evaluating impacts of VRE on total system costs and electricity generation revenue.

2.3 Demonstrating and analyzing the VRE impact mitigation.

3. Defining the scopes of work.

4. Collecting the relevant simulation data.

5. Developing the method to determine the impacts of VRE integration on total system costs and electricity generation revenue using MATLAB.

6. Developing the method to mitigate VRE impacts by enhancing system flexibility and by a bidding strategy using MATLAB.

7. Analyzing and concluding obtained simulation results.

8. Presenting the dissertation.

1.4 Expected Benefits

The expected benefits of this dissertation are as follows.

1. Determination of the impacts of VRE integration on total system costs and electricity generation revenue.
2. Realization of the relations between VRE penetration and the impacts of VRE integration.
3. The appropriate ways to mitigate the VRE impact on total system costs and electricity generation revenue.
4. Guides to determine VRE plans and policies consistent with the systems' technical and economic perspectives.

1.6 Literature review

This dissertation proposes a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue, as well as assess the VRE impact mitigation. Therefore the literature review related to this dissertation can be separated into two groups. First is the literature review about the determination of VRE integration impacts. Second is the literature review about the mitigation of the VRE impacts.

1. The determination of VRE integration impacts

The VRE integration impacts have been an issue in many works. Those works mostly reflect the impacts of VRE integration either on technical issues, i.e., electrical system planning and operation, or economic issues, i.e., market value. Many studies have proposed tools to determine optimal VRE penetration considering integration costs, most of which are techno-economic models [6, 62]. Research [12, 15, 16, 22] used indicator/adjustors called 'System values' and 'System costs' to compare resources. They were then used to derive the costs-optimal share of VRE by comparing the system value to the Levelized Costs of Electricity (LCOE) and the system costs to the average annual electricity price. For example, according to Figure 1, integration costs can be accounted by reducing the market value of VRE compared to the average electricity price (value perspective). Alternatively, they can be accounted by adding them to the generation costs of VRE to become system LCOE (cost perspective). The welfare-optimal deployment $q*$ is defined by the intersection of market value and LCOE, equivalently, by the intersection of system LCOE with the average electricity price. Moreover, research [65] estimated the welfare-optimal market share of wind and solar generation in Northwestern Europe, explicitly considering their output variability. The research presented a theoretical valuation framework that consistently accounted for the impact of fluctuations over time, forecast errors, and the location of generators in the power grid on the marginal value of electricity from VRE generation, where marginal value is Levelized income from electricity sales. In addition, the effects of technological change, price shocks, and policies on the optimal share were evaluated. The research found that the optimal long-term wind share is equal to 20%. In contrast, solar PV's optimal share is close to zero because solar PV has a marginal value at low penetration lower than its Levelized Cost of Electricity (LCOE) or Levelized Electricity Cost (LEC). Noted that the analysis was studied in 2015. Moreover, the research found that fluctuations dramatically impacted the optimal wind share. Specifically, temporal fluctuations had a huge impact on these results, e.g. if wind provides constant generation, the optimal share would triple. In contrast, forecast errors had only a moderate impact; without balancing costs, the optimal share would increase by only eight percentage points. In addition, climate, policy, technical integration measures, and fuel prices did not change the picture qualitatively. The impact of interconnector expansion and new turbine technology was positive but moderate in size, and the most significant impact was thermal plants' flexibilities.

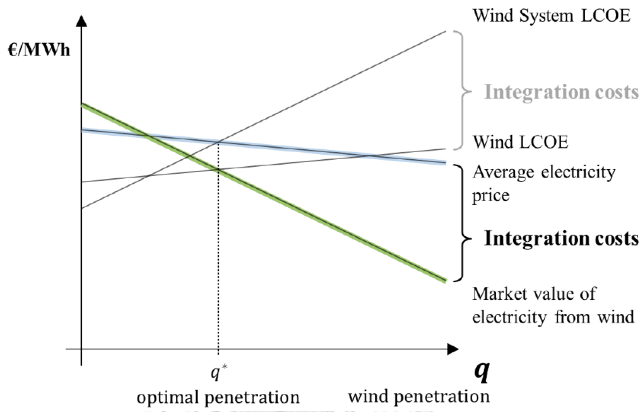


Figure 1 Determining VRE optimal penetration using system value and system cost.

However, the indicator/adjustors approach is used for comparing different kinds of generation technology—for example, between solar and wind. The approach requires calculating the cost of a specific electrical system, categorizing the cost component elements, and attributing these elements to certain kinds of generation technology, which may lead to controversies about the quantification of integration costs—or, in other words, the question of deciding "who's to blame" [7]. In terms of setting VRE plans and policies, policymakers must focus on overall costs to determine an optimal system plan and policy options that compile all costs and effects incurred in the system. For this purpose, the "total system cost approach" is more appropriate. The total system cost approach can establish the optimal generation mix to meet the electricity demand at the lowest costs. The approach allows for the evaluation of the costs incurred in electrical systems from all generators and avoids the controversy over cost allocation to a specific kind of generation technology [5, 7].

Existing studies have included total system costs in their models to determine VRE penetration 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. Study [63] provided an optimization method for California energy system modeling: the minimization of total system costs consisting of the annuity of investment, fixed, variable, and fuel costs. The main constraint was satisfying demand in each region for each hour of the year. The method was a linear optimization. The result showed that, between 2016 and 2030, California has to install around 11.5 GW of PV and 1.3 GW of onshore wind in-state and will rely on an additional 11.5 GW of out-of-state PV and 6 GW of onshore wind from Wyoming. The system costs will increase by 15% compared to 2016. Further research [64] has pointed out that costs increase from 0.031 $/kWh at 15% RE share to 0.047 $/kWh at 45% RE share. The breakdown of costs associated with increased renewable penetration is shown in Figure 2. Research [74] 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, despite considering that they should be regarded for the economic evaluation of generators [75].

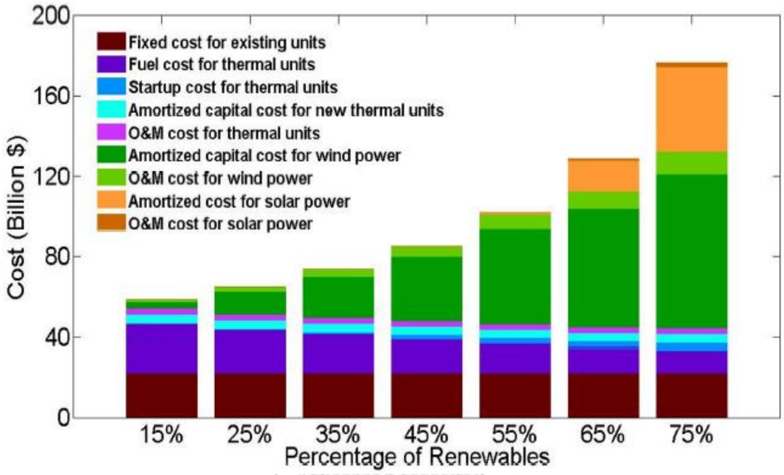


Figure 2 The breakdown of costs associated with increased renewable penetration.

Indirect integration costs were mentioned in [76, 77]. Research [76] 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 [77] evaluated the impacts of wind penetration on electricity prices and the fixed cost recovery of conventional generators. Nonetheless, research [76, 77] did not consider the impact of solar integration, which also plays an important role in many countries' electrical systems.

2. The mitigation of the VRE impacts

Many works have considered mitigating the VRE impacts by enhancing the flexibility of existing power plants. Research [64] proposed a novel capacity expansion model optimizing investment decisions and full-year, hourly power balances simultaneously, with considerations of energy storage technologies, policy constraints, and all system flexibility constraints i.e., ramping, reserve, minimum output, and minimal online/offline time. The proposed model was applied to the northwestern grid of China to examine the optimal composition and distribution of power investments with a wide range of RE generation targets. Properly designing the generation portfolio in the research consists of prioritizing wind investments, distributing RE generation investments more evenly, and deploying more flexible midsize coal and gas units. The results indicated that overall cost could be increased moderately towards 45% of the required fraction of power demand served by RE generation, and reaching higher penetrations of RE is expensive. Thus, the reductions in storage costs were critically important for an affordable low-carbon future. Research [68] states that reducing minimum load levels has proven to bring the most benefits. Important enabling factors are adopting alternate operation practices, rigorous inspection, and training programs. Several retrofit measures were implemented on German power plants to enhance their flexibility. For example, coal power plant Bexbach (780 MW) reduced of minimum load from 170 MW (22% of P_{Nom}) to 90 MW (11% of P_{Nom}) by switching from two mills to a single mill operation. Unit G and H of hard coal power plant Wesweiler upgrades in plant engineering and control reduced the minimum load of 170 MW and increased the ramp rate by 10 MW/min. The total retrofit cost amounted to around 60 M€ for each unit. Investment costs for retrofit in flexibility can be roughly estimated in a range from 100 to 500 €/kW. It must be evaluated case by case. Retrofit usually increases the technical lifetime of a power plant by about 10-15 years. Research [69] stated that operating a plant flexibility increases operation and maintenance costs. However, these increases are small compared to the fuel savings associated with higher shares of renewable generation in the system. Nonetheless, research [64, 68, 69] did not consider indirect integration costs and did not point out the outcome on electricity markets. According to research [20], in the United States, the average reductions in MPs for an additional percentage of VRE penetration are 0.19–0.81 $/MWh before curtailment and 0.21–0.87 $/MWh after curtailment is shown in Figure 3 and Figure 4.

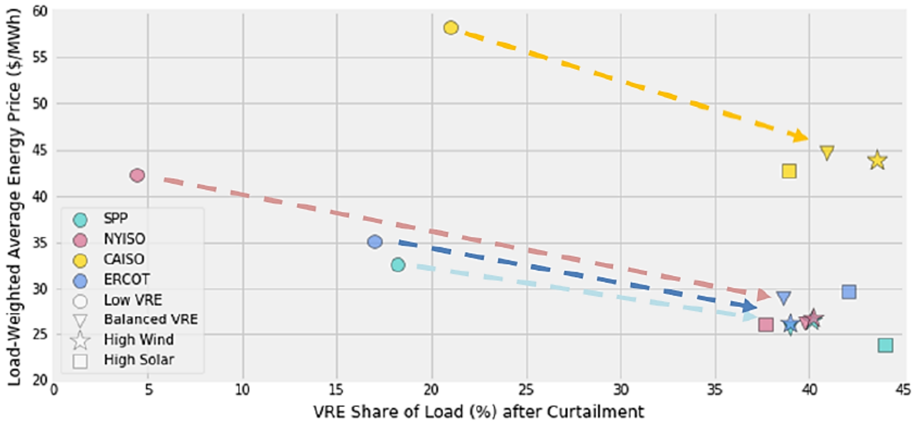


Figure 3 VRE Share of Load vs. Load-Weighted Average Energy Prices by Region.

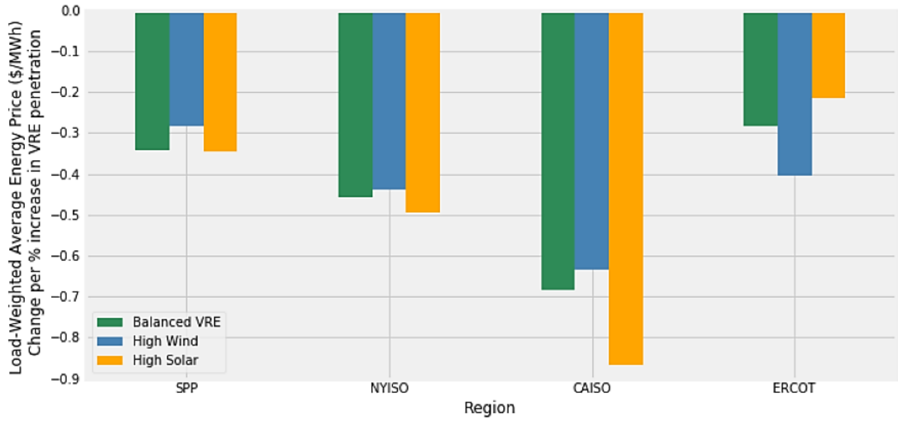


Figure 4 Energy price change with increasing VRE penetration across regions.

For the mitigation of the VRE impacts by bidding strategies, one of the bidding strategies is physical withholding, which can be considered as curtailment. Several studies have dealt with VRE curtailment optimization in generation systems; both technical and economic issues were considered. Research [72] demonstrated an analytical model that can solve a two-period unit-commitment problem considering the SOCs and a model of energy production to study the mechanisms of VRE curtailment for economic reasons. The beneficial finding was that if decisions to curtail VRE were taken by generators independently, it would result in a sub-optimal level of curtailment. However, the models aimed to minimize generation costs, not maximizing the generators' profits. Another research [36] illustrated the optimal VRE curtailment done by both system operators and VRE generators. The optimization considered the investment in system infrastructure. The compensation for curtailed generators was discussed. The study also found that optimal curtailment would be increased along with an increased share of VRE. The study pointed out the generators’ profits from the compensation. However, the authors did not focus on strategic bidding to maximize VRE generators’ profits. Moreover, they did not describe the relationship between the outcome of the physical withholding and the impacts of VRE integration on electrical generation revenue, although VRE curtailment effect wholesale markets’ marginal prices.

1.7 Dissertation Structure

The dissertation structure is organized as follows:

Chapter 1 Introduction: This chapter presents the problem statement that identifies an overview of the impacts of variable renewable energy (VRE) on total system costs and electricity generation revenue. The objectives of the dissertation are also stated. In addition, the scope of work, the step of the study, the expected benefits, the literature reviews, and the dissertation structure are included are all provided.

Chapter 2 Impacts of variable renewable energy integration: This chapter provides background knowledge about RE, especially VRE. Global RE trends, VRE characteristics, and the impacts of VRE on electrical system operation and planning are presented. Finally, the impacts of VRE on electricity markets are illustrated.

Chapter 3 Evaluating the impacts of VRE integration: This chapter presents a comprehensive explanation of VRE integration costs and approaches for determining the impacts of VRE integration on total system costs, as well as approaches for evaluating VRE impacts on electricity generation revenue.

Chapter 4 VRE impact mitigation: The VRE impacts on total system costs and electricity generation revenue are confirmed by many studies as presented in the previous sections. This chapter provides the VRE impact mitigation from both the electrical system’s side, i.e., enhancing system flexibility, and the market's side, i.e., bidding strategy.

Chapter 5 The proposed method for determining the impacts of VRE integration and assessing the mitigation of the impacts: This chapter presents the proposed method for determining the impacts of VRE integration and the method to assess the mitigation of the impacts. This chapter consists of two parts. First is the method to determine VRE integration's impacts on total system costs and electricity generation revenue. Second is the assessment of VRE impacts mitigating by enhancing system flexibility, and the method to mitigate VRE impacts by using a bidding strategy

Chapter 6 Data and assumptions: This dissertation used Thailand’s electrical system as the test system. Although the system is a system with a vertical structure, this dissertation assumed it as a liberalized structure. This chapter presents the data used in this dissertation.

Chapter 7 Result and discussion: This chapter presents results and discussions. The results of electrical system planning, determining the impacts of VRE integration by performing the methods, and the results of VRE impacts mitigation by performing the methods are shown.

Chapter 8 Conclusion: This chapter summarizes the conduct of this dissertation and proposes.

Chapter 2

Impacts of VRE integration

Renewable energy (RE) continues to grow in importance for electrical systems because of a rapid decline in investment costs, their use of free energy from nature, and environmental friendliness [1]. RE generation resources include both dispatchable RE sources, such as hydro, and non-dispatchable RE sources known as variable renewable energy (VRE), such as solar and wind. VRE forms a substantial proportion of RE targets in many countries [2, 3]. However, integrating VRE poses challenges to electrical systems from both technical and economic perspectives. This chapter provides background knowledge about RE, especially VRE. Global RE trends are presented in Section 2.1, VRE characteristics in Section 2.2, and the impacts of VRE on electrical system operation and planning in Section 2.3. Finally, in Section 2.4, the impacts of VRE on electricity markets are illustrated.

2.1 Global trends in renewable energy

According to [3], the global RE generation capacity at the end of 2020 is 2,799 GW. Hydropower accounted for the largest share, with a capacity of 1,211 GW. Wind and solar generation accounted for equal shares of the remainder, with capacities of 733 GW and 714 GW respectively. Other renewables included 127 GW of bioenergy and 14 GW of geothermal, plus 500 MW of marine energy. Figure 5 shows RE generation capacity by energy source. Note that the figure excludes pure pumped storage. In end-2019, this was an additional 121 GW, giving a total hydropower capacity of 1,332 GW.

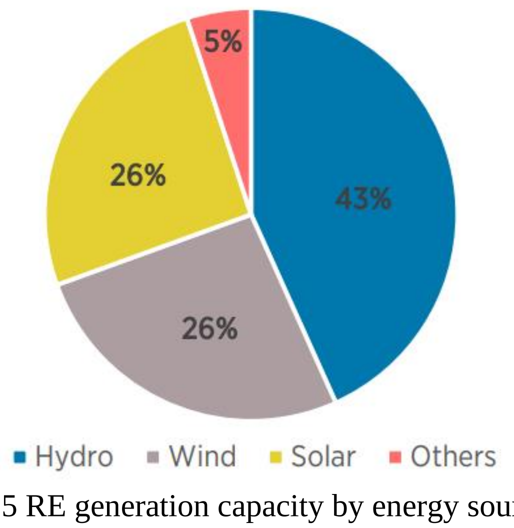


Figure 5 RE generation capacity by energy source.

RE generation capacity increased by 261 GW (+10.3%) in 2020. Solar generation continued to lead the capacity expansion, with an increase of 127 GW (+22%), followed closely by wind generation with 111 GW (+18%). Hydropower generation increased by 20 GW (+2%) and bioenergy generation by 2 GW (+2%). Geothermal generation increased by 164 MW. VRE, i.e., solar and wind, continued to dominate renewable capacity expansion, jointly accounting for 91% of all net RE additions in 2020. This exceptional growth in wind and solar led to the highest annual increase in RE capacity ever seen. Figure 6 shows RE generation capacity growth.

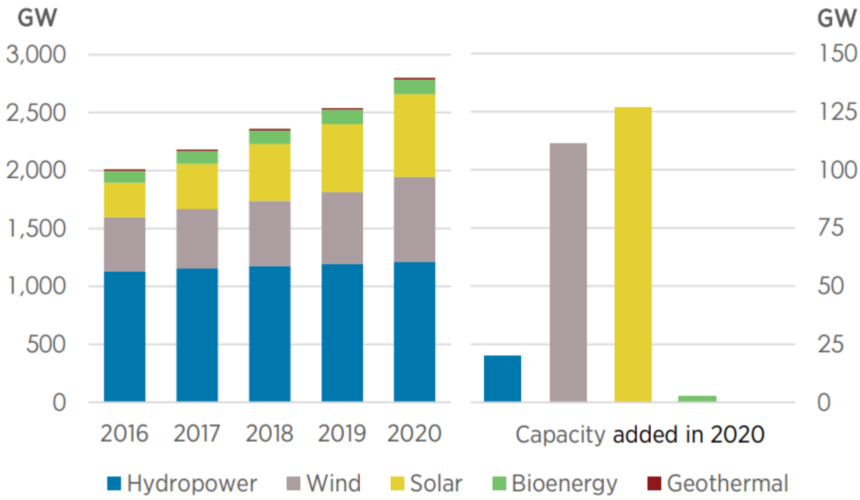


Figure 6 Renewable generation capacity growth.

Asia accounted for 64% of new capacity in 2020. It increases RE generation capacity by 167.6 GW to reach 1.29 TW (46% of the global total). A huge part of this increase occurred in China. In Europe and North America, Capacity expanded by 34 GW (+6.0%) and 32 GW (+8.2%), respectively, with a notably large expansion in the USA. Africa continued to expand steadily with an increase of 2.6 GW (+5.0%), slightly more than in 2019. Oceania remained the fastest-growing region (+18.4%), although its share of global capacity is small, and almost all this expansion occurred in Australia. Figure 7 shows RE generation capacity by region.

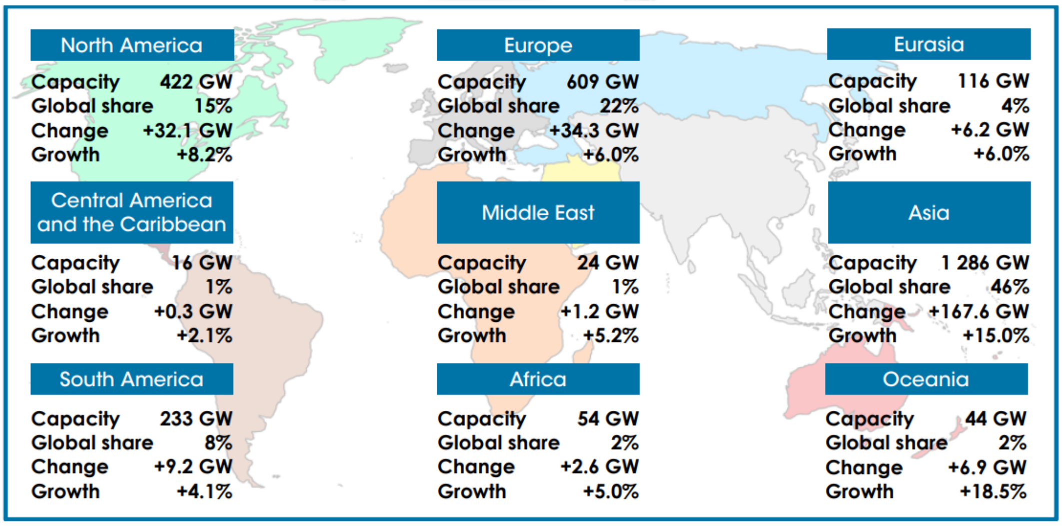


Figure 7 RE generation capacity by region.

The RE highlight growth distinguished by resources is as follows:

- **Wind:** Wind expansion almost doubled in 2020 compared to 2019 (+111 GW compared to +58 GW last year). China added 72.4 GW of new wind generation, followed by the United States (+14.2 GW). Ten other countries increased their wind generation by more than 1 GW in 2020. While offshore wind remains a small part of the sector, it continues to increase in importance each year and reached around 5% of total wind generation in 2020.
- **Solar:** With an increase in new capacity in all major world regions last year, total global solar generation has now reached about the same level as wind generation. The expansion in Asia was 78 GW in 2020 (compared to +55 GW in 2019), with major capacity increases in China (+49.4 GW) and Viet Nam (+11.6 GW). Japan also added over 5 GW. India and the Republic of Korea expanded solar generation by more than 4 GW. Outside Asia, the United States added 14.9 GW of solar capacity in 2020, Germany and Australia added over 4 GW, and the Netherlands and Brazil added more than 3 GW.
- **Hydro:** Growth in hydro recovered in 2020, with the commissioning of several large projects delayed in 2019. China added 12.1 GW of capacity, followed by Turkey with 2.5 GW.
- **Bioenergy:** Net capacity expansion fell by half in 2020 (+2.5 GW compared to +6.4 GW in 2019). Bioenergy generation in China expanded by over 2 GW. However, total net expansion in Asia was less than this due to reduced use of bioenergy in Japan and the Republic of Korea. Europe was the only other region with significant expansion in 2020, adding 1.2 GW of bioenergy capacity, a similar amount to 2019.
- **Geothermal energy:** Minimal geothermal capacity was added in 2020. Turkey increased capacity by 99 MW, and some small expansions also occurred in New Zealand, the United States, and Italy.
- **Off-grid electricity:** Off-grid capacity grew by 365 MW in 2020 (+2%) to reach 10.6 GW. Bioenergy generation fell slightly to 4.6 GW due to the grid connection of some plants. Solar generation expanded by 250 MW to reach 4.3 GW and hydro generation remained almost unchanged at about 1.8 GW.

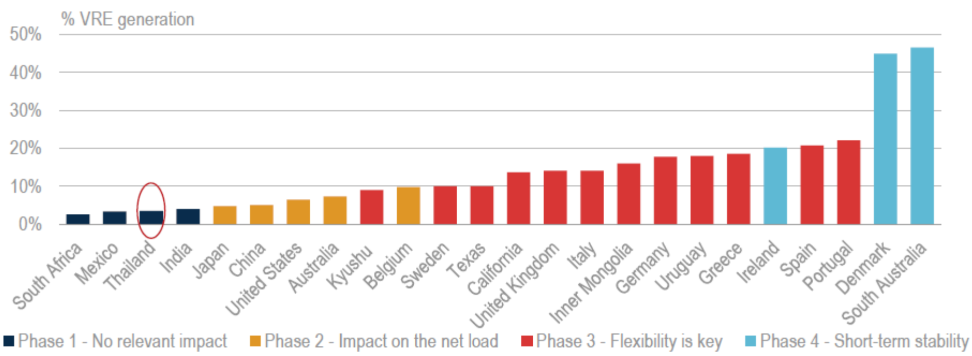
VRE accounts for a sizable portion of RE targets in many countries. In conventional generation-based systems, electrical system planners have always had to deal with variability and uncertainty to some extent. However, when VRE is integrated, it poses distinct impacts because of its characteristics rigorously reviewed in Section 2.2. According to [18], IEA analysis has identified distinct phases of VRE integration, differentiated by the impact VRE has on power system operation. There are four phases of VRE system integration:

- **Phase 1:** The first set of VRE plants are deployed, but they are insignificant at the system level; effects are very localized, for example, at the grid connection point of plants.
- **Phase 2:** As more VRE plants are added, changes between demand and net demand become noticeable. Making upgrades to operational practices

and making better use of existing system resources are usually sufficient to achieve system integration.

- **Phase 3:** Greater swings in the supply-demand balance prompt the need for a systematic increase in power system flexibility that goes beyond what can be relatively easily supplied by existing assets and operational practices.
- **Phase 4:** VRE output is sufficient to provide a large majority of electricity demand in certain periods; this requires changes in both operational and regulatory approaches. Regarding operations, this relates to the way the power system responds immediately following disruptions in supply or demand to maintain system stability. Regarding regulations, it may involve rule changes so that VRE is enrolled to provide frequency response services or the relaxation of take-or-pay contracts for power purchase and/or fuel procurement contracts.

Most countries are in phases 1 or 2. However, some countries are experiencing later phases. Figure 8 shows selected countries by VRE phase in 2016. For example, in Thailand, VRE generation is becoming noticeable to the system operators. Therefore, Thailand can be in Phase 1, approaching Phase 2 of VRE integration.



Note: China = the People's Republic of China. Kyushu is one of the large islands in Japan located in the southwest.
Source: Adapted from IEA (2017c), *Renewables 2017: Analysis and forecasts to 2022*.

Figure 8 Countries by VRE phase in 2016.

2.2 Characteristics of VRE

VRE generation is variable, with limited predictability, and the resources are site-specific. These characteristics lead to several challenges in terms of integrating VRE into electrical systems. The source of energy to be converted to electricity varies over time in a non-controllable way from fractions of a second to hours or days. This results in a forecast error of the power output from VRE power plants. While there have been significant advances in wind and solar forecasting with important benefits in managing the variability, the limited predictability of wind and solar resources remains a challenge in integrating high levels of VRE into an electrical system. In addition, the resources are specific to the location. Wind speeds vary with terrain and weather patterns. The siting of a wind power plant and even the siting of the individual wind turbines within a wind power plant are based on site-specific mapping, measuring, and detailed modeling. Solar insolation also varies with latitude, environmental factors such as the amount of dust or air pollution, shading from nearby structures or natural features, and weather patterns [43].

2.2.1 Variability

In terms of wind generation, the electrical output of wind turbines varies with the fluctuating wind speed at all characteristic timescales relevant for electrical system planning and operations, i.e., fractions of a second to years. On the positive side, wind generation has a high potential for geographic distribution, i.e., siting wind power plants in widely separated geographic locations so that wind patterns determining the power output of one wind power plant are independent of those from a distant wind power plant. This helps to reduce the aggregated variability, as the output of the turbines becomes less correlated, as shown in Figure 9. Despite the positive effect of aggregation, wind can stop blowing in a large area within a short period of time, causing rapid reductions in power output. According to [43], In Denmark, the aggregated wind capacity dropped 90 percent (2,000 MW) over 6 hours in January 2005. In February 2007, 1,500 MW were lost within 2 hours in Texas, and in 2009 Germany faced the challenge of coping with a change of 30 GW within a few hours. Conversely, a weather event could also suddenly increase generation output, requiring the curtailment of many wind turbines. The probability of this type of event is low, but the impact on operations is highly challenging.

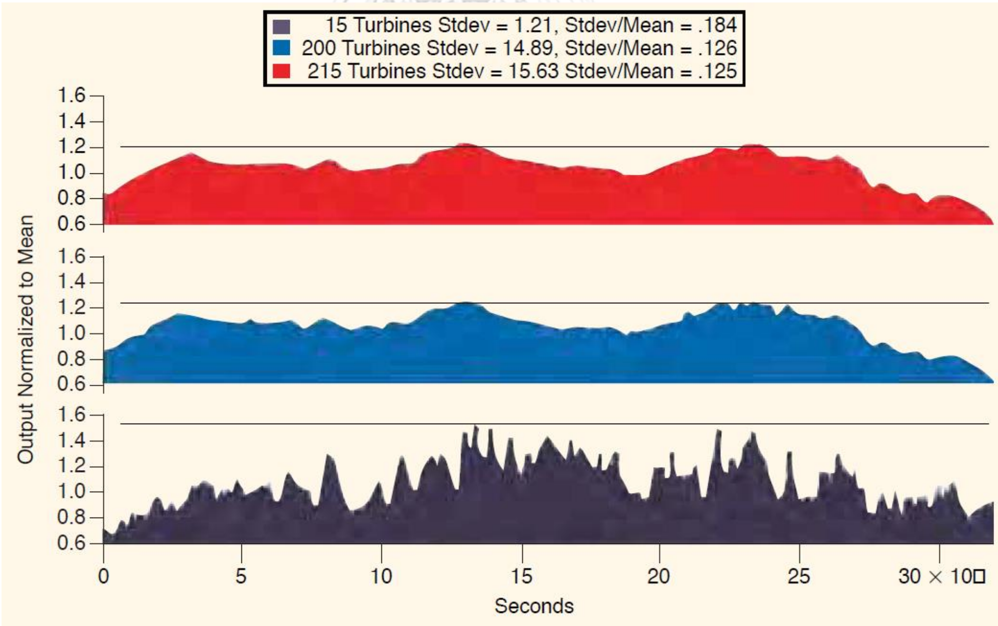


Figure 9 Effect of Wind Aggregation on Variability.

There are two types of grid-tied solar power technologies for solar generation: PV and CSP. PV makes use of semiconductors for the direct conversion of sunlight to electricity. Therefore, PV electrical generation changes nearly instantaneously with changes in solar radiation. Individual solar plants can have extreme variability on cloudy days. In general, the larger the footprint of the power plant and the larger the geographic dispersion between sites, the lower the combined variability, as shown in

Figure 10. This is one advantage of distributed PV generation compared with a centralized PV power plant. The degree to which the variability is reduced depends on both the type of technology and the prevailing weather patterns. Commercially available CSP technologies reflect and concentrate the sunlight onto a receiver, where the heat transfer fluid (HTF) is heated. This heat is transferred to water in a heat exchanger, and the steam generated is used to drive a steam turbine and produce electricity. CSP benefits from the working fluid's thermal inertia, which allows CSP to have slightly lower intra-hour variability than PV. It depends on the specific CSP technology and whether or not the design incorporates gas as auxiliary fuel during transient cloud conditions. It also delays the generation start-up at sunrise and delivers power for some additional minutes after sunset, compared with PV. The thermal inertia of the working fluid can be exploited further by incorporating additional thermal energy storage (TES), usually using tanks of molten salts, in the CSP plant design, which increases a CSP power plant's capacity factor. Most of the CSP power plants currently under development incorporate some TES that charges entirely from the solar field and is used to generate steam when required by the operator. Therefore, CSP with storage is not usually considered VRE since TES can eliminate short-term variability and shift generation towards peak demand times, appearing to the operator as a conventional thermal plant.

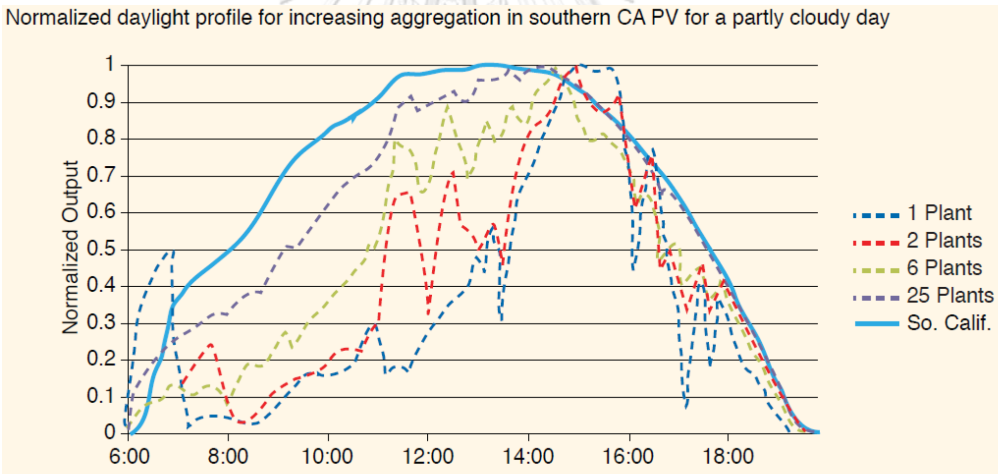


Figure 10 Comparison of Photovoltaic Power Production Variability in Southern California, USA.

A mix of VRE technologies within a balancing area can have important advantages in terms of reducing the variability of the overall VRE contribution, depending on the weather conditions and if those lead to complementary generation patterns. As an example, a recent report by the Fraunhofer Institute shows that high solar irradiance and high wind speeds tend to be negatively correlated in time in Germany. As a result, the combined monthly aggregated generation of the 35 GW of PV and 32 GW of wind capacity installed is less variable than wind and solar outputs separately, as shown in Figure 11.

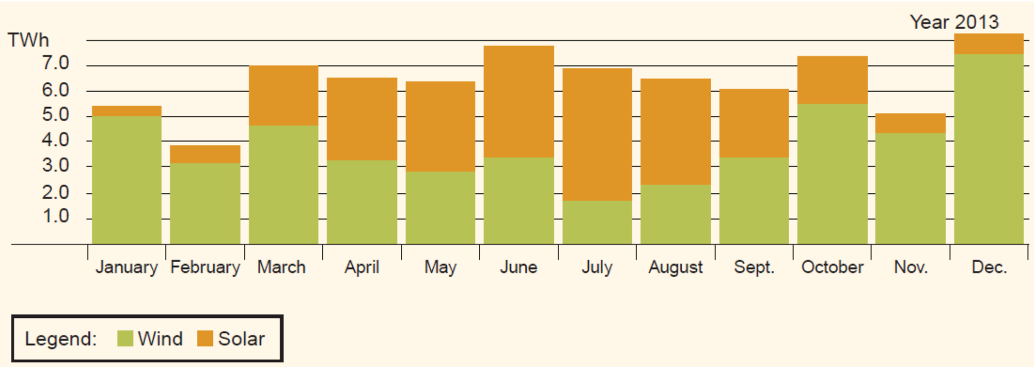


Figure 11 Monthly Solar Photovoltaic and Wind Power Production, Germany (2013).

2.2.2 Limited Predictability

Different forecasting errors can measure the predictability of VRE. The most widely used are mean absolute error (MAE) and root mean squared error (RMSE). At present, it is possible to predict the generation of individual wind power plants one or two hours ahead with mean absolute errors (MAE) below 5 percent of rated wind generation capacity. It is more challenging to predict generation a day ahead (MAE is usually between 10 and 20 percent of rated power), and the terrain's complexity plays an essential role in the performance of the forecast models. Wind power plants in highly complex landscapes have shown day-ahead errors as high as 35 percent (IEC). Wind energy output forecast errors decrease with increasing numbers of wind turbines and larger geographic dispersion. In the state of Minnesota, the USA, the day-ahead MAE was reduced from 20 to 12 percent with the aggregation of the output of only four sites. For a larger geographical area like Germany, day-ahead MAE can be lower than 5 percent. In most countries with high shares of VRE, wind forecasts have improved significantly due to targeted research and development (R&D) efforts over the last decade.

PV generation variability associated with sunrise and sunset is predictable. In fixed-tilt installations, the shape of the PV output profile depends on the orientation of the PV panels. The orientation of the panels is fixed, while the position of the sun changes during the day and the seasons. The orientation of the panels determines the power output and the time of the daily peak. The output of PV plants with tracking systems—which adjust the orientation of each panel during the day and the year to maximize power output—shows more rapid ramp-ups and downs at the start and end of the day compared to those that use fixed-tilt panels. However, the effect of clouds or sandstorms is difficult to anticipate. Solar forecasting is not yet as developed as wind forecasting, but the rapid growth of PV deployment in both utility-scale and small-distributed systems is driving several countries to coordinate R&D programs to enhance solar forecasting.

2.2.3 Site-Specific

The technical feasibility of VRE depends fundamentally on the quality of wind or solar resources at a specific site. Therefore, unlike conventional power plants, the geographic location of VRE generators is often determined by the availability of enough resources to ensure a relatively high energy yield. In many cases, the good

VRE sites are located in remote areas, far from existing transmission infrastructure, demanding adequate transmission planning and policy decisions about who should bear the cost of the required transmission interconnections and potential system-wide upgrades.

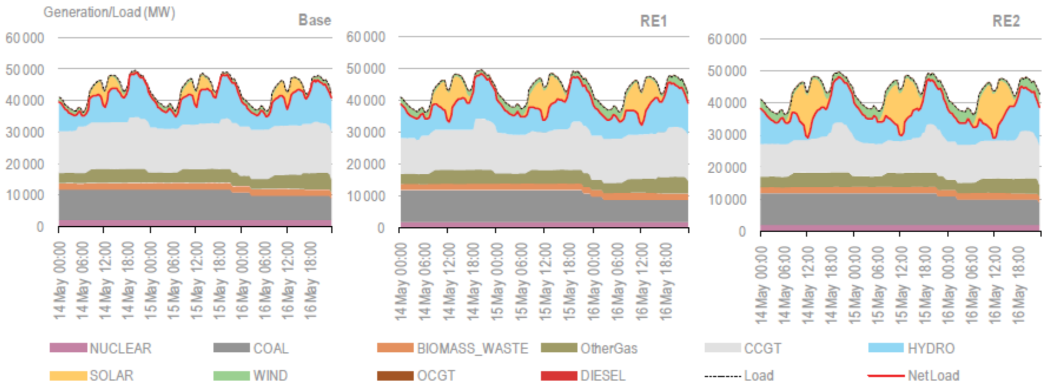
In the case of wind, off-shore wind turbines can perform at higher capacity factors than on-shore wind power plants, but transmission costs are higher since off-shore power plants necessitate the use of high-voltage, high-capacity submarine cables. For solar, site resource dependency is more pronounced in the case of large wind or CSP projects than for PV, which can produce energy even at low levels of irradiation, though at a higher cost. CSP plants are technically and economically feasible only in locations with high direct normal insolation (DNI).

2.3 Impacts of VRE on electrical system operations and planning

VRE integration has several operational impacts on the power system. The uncertainty and variability of wind and solar generation can pose challenges for system operators. Variability in generation sources can require additional actions to balance the system. Greater flexibility in the system may be needed to accommodate supply-side variability and the relationship between generation and demand.

To illustrate the impacts of VRE on system operation, IEA evaluates the impacts of VRE in Thailand's electrical system at three different levels of VRE in [18]. First, 'Base' is the year 2036 scenario using existing official targets of 6 GW solar and 3 GW wind (2015). Second, 'RE1' is the year 2036 scenario with 12 GW solar and 5 GW wind. Third, 'RE2' is the year 2036 scenario with 17 GW solar and 6 GW wind. During the peak demand period, there is sufficient generation to handle the high demand, although some of the peaking plants, such as diesel gas turbines (GTs), which are the system's least economical units, need to be dispatched. This peak period, which occurs in May, also coincides with the high solar photovoltaic (PV) output periods. Additional VRE is shown to benefit the system by displacing conventional generation, particularly CCGT plants, since they are operated as load-following plants as shown in Figure 12. VRE generation displaces CCGT generation with little effect on other thermal generation. Additionally, it reduces net system peak demand and creates an evident trough in net demand around midday.

However, during the period of minimum load, which occurs at the end of the year, the traditional baseload plants, including coal and nuclear, are required to cycle more often as well as operate near the minimum generation as shown in Figure 13. VRE generation displaces generation from cheap, inflexible coal and nuclear units during the period of minimum load. As VRE penetration increases, this effect is amplified because of the greater variation in net demand, resulting in the shutdown of some coal units and increased cycling of nuclear generation output. During this period, hydro generation output is less as the share of VRE increases. However, hydro is required to cycle more frequently and to a greater degree due to its flexibility in ramping and start-up time. CCGTs must completely shut down in the minimum demand periods.



Note: *Other gas* refers to combined heat and power (CHP) from small power producer (SPP) and thermal gas power plants.

Figure 12 Generation output by technology during the period of peak demand (14-16 May 2036).

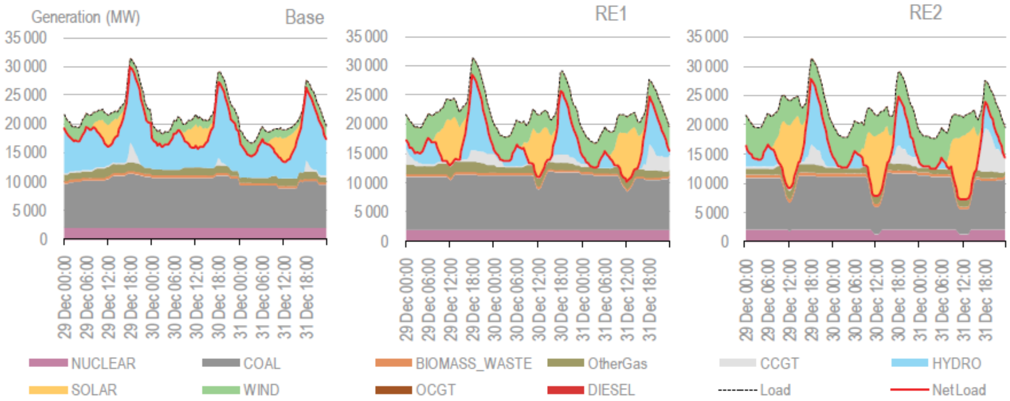


Figure 13 Generation output by technology during the period of minimum demand (29-31 December).

The impacts are also mentioned as the international experiences. Figure 14 provides an example of the flexibility needed for high penetration of wind generation in Minnesota, USA. Utilizing all the wind energy would require conventional generation to meet the net demand, which is defined as the demand minus the wind energy. The graph shows the demand and net demand for a sample week. There are periods when the net demand changes, or ramps, more quickly than the demand alone. Also, the remaining generators must be operated at a low output level, sometimes called ‘turndown’, at night when there is a lot of wind power. In contrast to wind, solar generation is often more coincident with demand. However, in regions with evening demand peaks, loss of solar generation at sunset can exacerbate ramping needs to meet the evening demand [44].

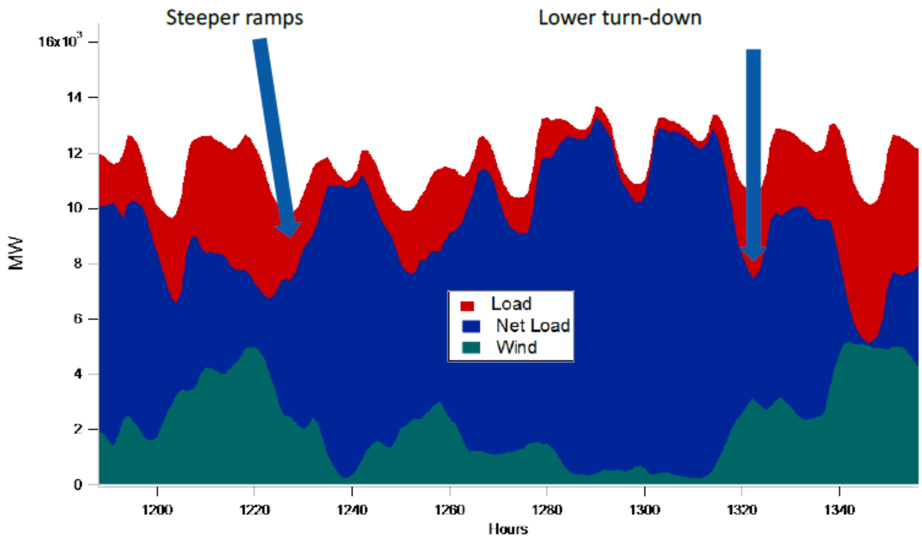


Figure 14 Wind energy requires additional flexibility from the remaining generators. (Data from Minnesota 25% wind energy scenario)

Electrical system operators must balance supply and demand to maintain high levels of reliability and stability and ensure acceptable quality of power supply. Figure 15 shows the definitions of reliability and stability of an electrical system, and how both contribute to the quality of the electricity supplied to the consumers [43].

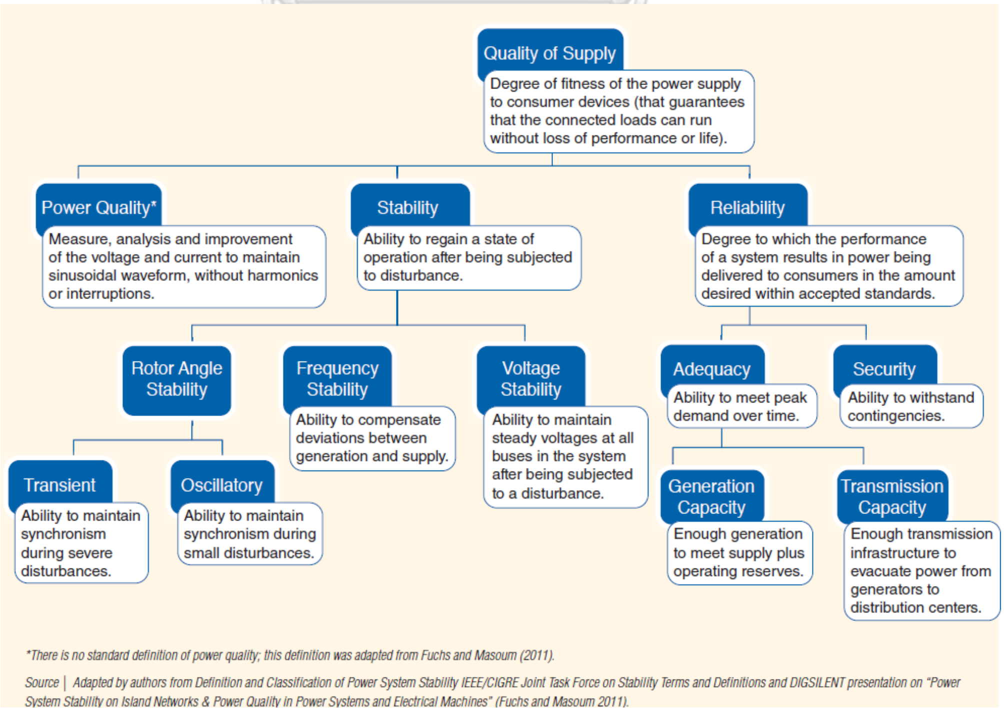


Figure 15 Stability and reliability as the pillars of quality of supply.

To achieve the required grid performance, operators need to have access to ancillary services to support energy transmission from generators to loads. Ancillary services include operating reserves, reactive power (to provide voltage support, i.e., increase voltage when needed), and black start (to restart the power system in case of a cascading black-out) (SNL). In practice, this means that operators hold generators in reserve to cover unexpected surges in demand and to cover loss of supply due to faults, planned outages, or reduced output from VRE. Demand and supply must be balanced at all times to avoid frequency deviations that may lead to forced load-shedding, i.e., power outage for one or more areas. The generating capacity committed to this purpose constitutes the operating reserves of a power system. The operating margin is the ratio between the generation capacity installed and the peak demand. Typically, operating reserves should be at least equal to the capacity of the largest generator plus a fraction of the peak load. However, the optimal operating margin for a system is dependent on several factors, including the size of the electrical system, the reliability level required, and the costs related to the operating reserve power plants. The speed of response to the operation signal from the operating reserves is also very important. A fraction of the operating reserves is comprised of "spinning reserves," generators that are kept online, running at part load to respond fast enough to the operator's dispatch instructions since ramp-up and down rates are much faster than start-ups and shutdowns. Note that the nomenclature of the characteristic timescales and associated operating reserves varies depending on the country. Figure 16 compares European and US terminology with definitions provided in the Glossary.

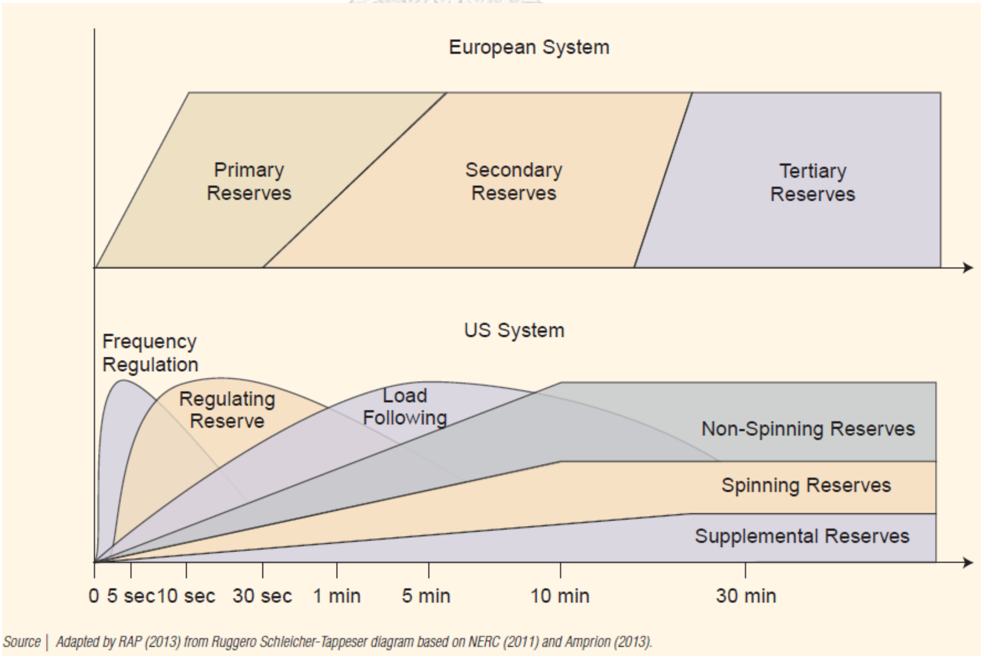


Figure 16 Comparison of European and US Operating Reserves Terminology.

At low levels of VRE penetration (generally below 5 or 10 percent, depending on the system's specific characteristics), the variability and forecast error of the net demand are dominated by the more predictable variability in power demand. In such cases, electrical systems can usually accommodate the integration of small amounts of VRE, using the existing operating reserves, by adjusting operating procedures. As the share of VRE increases, the variability and uncertainty exceeds the level typically covered by existing operating reserves, and additional measures are needed.

The VRE integration challenges for system operators and planners are due to the inherent characteristics of VRE resources, i.e., variable, with limited predictability and site-specific, and the system's characteristics into which they need to be integrated. VRE integration challenges and costs will depend on the existing flexible resources and the quality of electricity supply required. In systems where consumers require high reliability and power quality, system operators may need to spend additional resources to minimize the potential imbalances or disturbances introduced by VRE, since the cost of loss of load or damage to equipment, both leading to loss of production, would be high. The following sections summarize the main challenges of electrical system operation and planning. Figure 17 shows a simplified summary of the main impacts that high shares of VRE can have on electrical systems, highlighting the range of timescales at which the variability may be experienced [43].

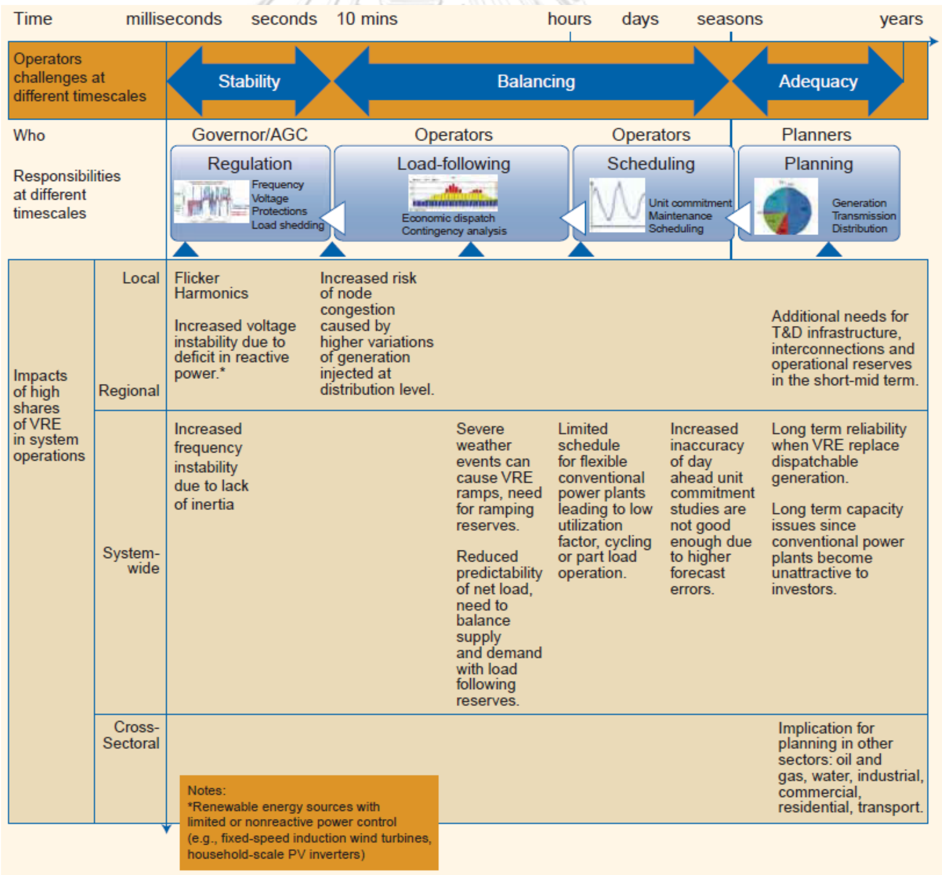


Figure 17 Potential impacts of high shares of VRE on electrical system operations and planning.

From Figure 17, the potential impact of high shares of VRE on power system operations and planning consists of four issues as follows:

- **Planning:** First, generation and transmission adequacy. Peak availability for VRE resources can often occur during relatively low electricity demand periods, leading to the risk of over-generation at high shares of VRE. The reverse can also occur: VRE output may not be available during peak demand times. Ensuring sufficient capacity is available to meet peak demand over time, i.e., fulfilling the adequacy criteria, taking into account an increasing share of VRE is an important challenge in system planning. The site-specific nature of VRE resources is also a factor to be included in planning for system adequacy, particularly transmission adequacy. The best wind or solar resources sites may be far from the main consumption centers and existing power lines. For example, only 7 percent of the USA population resides in the ten states with the highest wind potential. One of the main challenges for developing and integrating VRE into an electrical system is properly planning for transmission expansion to connect VRE power plants to the grid. Overall system expansion planning must consider options for VRE power plant siting, recognizing that the best resource sites from the perspective of maximizing the output from an individual VRE power plant may not be the best from the point of view of connecting supply with sources of demand. Transmission and distribution limitations, e.g., bottlenecks, lack of financing, and non-existent or unclear expansion regulation, may need to be addressed. Therefore, characteristics of the demand, i.e., growth, variability, and correlation with VRE generation, must be considered in planning the best approaches to integrating VRE.

  Second, planning for increased distributed VRE. One of the potential benefits of VRE is the possibility for distributed generation, such as rooftop PV systems, to feed into the distribution grid. As discussed above, more excellent dispersion can help limit aggregate variability and potentially reduce losses as the distance between power generation and use is shortened. These benefits have contributed to a growing trend in VRE distributed generation. However, distributed generation can pose some challenges that need to be managed. Distribution grids are traditionally designed as passive networks that transfer bulk power from the transmission system to customers. If not properly managed, VRE generation connected to the distribution grid may cause short-circuiting behavior of components due to improper protection, high fault currents, or voltage fluctuations. These impacts can be technically solved with the use of adapted inverters or transformers, but it will impact the system cost. Suppose distributed VRE contribution is expected to be significant. In that case, the planning process may need to assess smart grid approaches, such as innovative voltage control and power flow management, dynamic circuit ratings, and demand response, that transform the distribution system from a passive to an "active" network. This would allow VRE distributed generation systems and consumers to work reliably as virtual power plants.

  In addition to the operational issues posed by distributed generation, there is also a potential impact on the traditional utility model. In countries with increasing retail tariffs and VRE incentives e.g., Germany, Australia, or some of the USA states such as California, self-generation based on renewables has become an attractive proposition for electricity consumers, creating a new class of prosumers, efficient end-users that meet part of their electricity needs with distributed generation. Utilities have lost the regular revenue that is used to come from these prosumers while still having to provide them a reliable service when the distributed power generation is insufficient to supply the prosumer's total demand. Additionally, the utility's fixed and maintenance (O&M) costs remain at the same levels or may even increase. Some experts envision an evolution of utilities towards a business model similar to the one used by mobile networks, with higher fixed charges and different service packages.

- **Scheduling and Load Following:** Generation variability and limited predictability present challenges in balancing or matching the power generation and demand in the range of minutes to hours. From an operational point of view, the characteristics of the power output have implications for plant scheduling i.e., advance notice in terms of hours or days for individual power plants to be committed to generate at a given output level, and load following i.e., actually utilizing the generation from power plants to meet the load. To maintain the balance between generation and load, the system needs to be able to respond when VRE output changes, as shown in Figure 18. The response needs the system to ramp up or down on the same timescales as the changes in VRE output. At high levels of VRE, generation variability leads to the need for greater flexibility in the rest of the system to allow economic dispatch, while the limited predictability of VRE output can potentially lead to the need for increased load-following reserves to compensate for the increased uncertainty in the net load

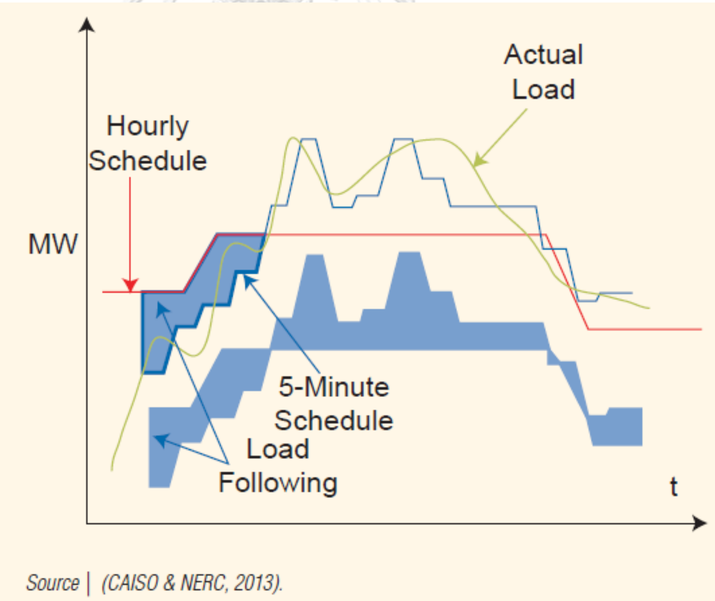


Figure 18 Balancing (load following) requirement (blue).

- **Regulation:** Steady-state stability, which is the instantaneous matching of supply and demand to maintain frequency, is required. From an operational point of view, VRE variability and relatively limited predictability lead to challenges in maintaining the overall stability of the power supply in terms of ensuring that actual, instantaneous power generated exactly matches actual, instantaneous power demand to avoid frequency deviations in the power system. In the timescales of milliseconds to minutes, frequency, voltage, and rotor angle stability fluctuations are usually managed by automatic control systems. In modern systems, signals are automatically sent to one or more generators to cause an increase or decrease in power output to match the changing load conditions and keep the frequency within specified limits. The service provided by this process is called regulation, as shown in Figure 19. At very high shares of VRE, particularly PV, the automatic regulation reserves, i.e., a subset of the operating reserve capacity, need to be able to respond much faster, more frequently, and within wider operation ranges to compensate for frequency deviations.

In addition to the stability issue linked to the short-term unpredictable variations of VRE is system dynamic stability. There is also another indirect impact on stability at high penetration levels of VRE. A grid disturbance, such as the sudden loss of a large generator, may cause large frequency fluctuations. The rotating inertia of the large rotating masses of conventional generators, such as in steam or gas turbines, helps to arrest fluctuations and stabilize system frequency following such a disturbance. VRE generation has limited capability to provide the system with such frequency response services compared to conventional generation. PV solar generation offers no rotating inertia and, therefore, no frequency response. Some modern wind generation technologies are designed to provide frequency response, though older designs generally do not have this capability. The displacement of the conventional generation that provides rotating inertia with low- or no-inertia VRE resources may raise stability issues as the VRE share increases. In general, this leads to greater frequency change rates in system contingencies, e.g., generating a unit loss or sudden load variations.

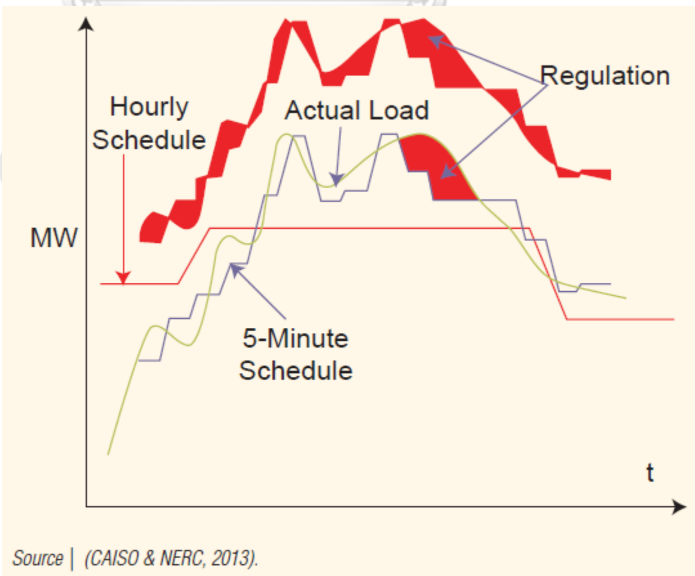


Figure 19 Regulation requirement (red).

According to [44], additional wind and solar power on electric grids can cause coal or natural gas-fired plants to turn on and off more often or modify their output levels more frequently to accommodate changes in a variable generation. This type of cycling of fossil-fueled generators can increase wear-and-tear on the units and decrease efficiency, particularly from thermal stresses on equipment because of changes in output. Costs of cycling vary by type of generator. Generally, coal-fired thermal units have the highest cycling costs, although combined-cycle units and many combustion turbines, unless specifically designed to provide flexibility, can also have high costs. Hydropower turbines, internal combustion engines, and specially designed combustion turbines have the lowest cycling costs.

For coal plants, in particular, the impacts can include increased damage to a boiler as a result of thermal stresses, decreased efficiency from running a plant at part load, increased fuel use from more starts, and difficulties in maintaining steam chemistry and NOX control equipment. Start-up costs are also influenced by how cold a unit is when it is being started. For example, hot starts, i.e., restarting a unit within 12 hours while a boiler and turbine are still relatively hot, have fewer impacts than cold starts, i.e., when a unit has been idle for three days and has cooled. A study by Xcel Energy found that for a 30-year-old 500-MW coal plant, costs ranged from \$153,000 to \$201,000 per cold start, whereas hot start costs ranged from \$82,000 to \$110,000. However, costs are specific to individual units and can vary by vintage, design, operating history, maintenance history, and operating practice.

The impacts on fossil-fueled generation from high penetrations of wind and solar generation (33% of generation) in the Western Interconnection of the United States were examined in detail by the WWSIS-2 study. It utilized cost data from hundreds of coal and natural gas plants regarding hot, warm, and cold starts, running at minimum generation levels, and ramping. These costs were used in a production cost model to optimize commitment and dispatch decisions. The study found that high penetrations of wind and solar power lead to cycling costs of \$0.47/MWh to \$1.28/MWh per fossil-fueled generator. High penetrations of wind- and solar-induced cycling cost \$35 million/year to \$157 million/year across the West while displacing fuel costs saved approximately \$7 billion.

2.4 Impact of VRE on electricity generation revenue

Besides operations and planning, VRE generation also impacts electricity generation revenue by inefficient power plant utilization and changes in electricity market activities.

2.4.1 Inefficient power plant utilization

The share of VRE decreases the utilization of conventional generation. The energy supplied by conventional generators is reduced while their capacity is still needed as backup for VRE sources. For example, research [18] evaluates the impacts of VRE in Thailand’s electrical system at three different levels of VRE. First, ‘Base’ is the year 2036 scenario using existing official targets of 6 GW solar and 3 GW wind (2015). Second, ‘RE1’ is the year 2036 scenario with 12 GW solar and 5 GW wind. Third, ‘RE2’ is the year 2036 scenario with 17 GW solar and 6 GW wind. The annual generation duration curve (GDC) of different technologies displays the utilization trend, influenced by the operational and economic characteristics of generation technologies, as shown in Figure 20.

The greatest noticeable difference in generator utilization resulting from increased VRE deployment is in the operation of CCGTs and thermal gas plants, where relatively large amounts of energy are displaced by wind and solar PV generation (as represented by the area under the duration curves). There are some slight changes in the operation of hydropower as the use of this energy-constrained resource is shifted slightly to balance supply and demand with a greater share of VRE. Generation from CCGTs and thermal gas plants are displaced by wind and solar as the share of VRE increases. The GDCs are largely inelastic throughout the year for nuclear and coal-fired generation since they are operated as traditional baseload. These two technologies are largely inelastic to the increase of VRE generation in the core scenarios. The GDCs are almost identical with only very slight changes in the volume of energy (<0.3%) observed between different scenarios.

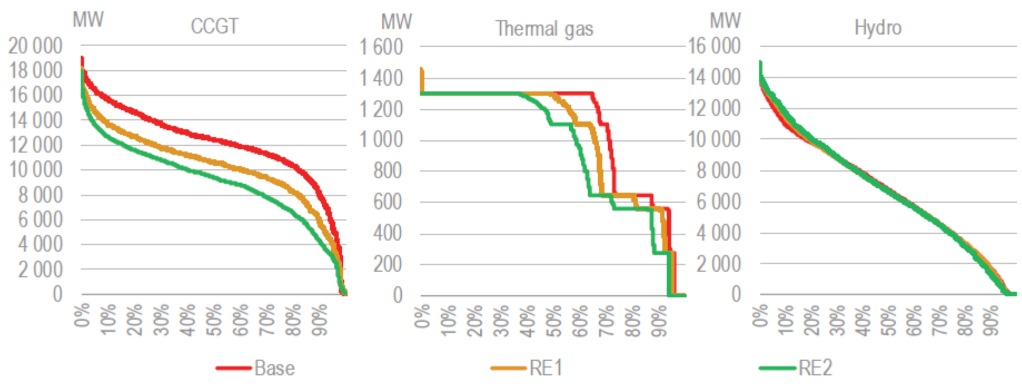


Figure 20 Generation Duration Curves (GDCs) of select technologies for different VRE scenarios.

In terms of the operation during the period of peak generation, the GDCs for the top 1% suggest that there are only subtle changes to their peak utilization for different VRE penetrations, as shown in Figure 21. CCGTs face the greatest changes since their peak generation is reduced by around 700 MW in RE1 and 1 000 MW in RE2 when compared to the Base scenario. Utilization of diesel-fired GTs increase both in the total volume of generation and magnitude of peak generation as the share of VRE increases (a 20-MW increase and a 50-MW increase in peak generation levels in RE1 and RE2, respectively, from the Base scenario). The more expensive generation from diesel GTs exceeds that of CCGTs in open cycle mode due to their unavailability during the high system-stress periods, which require more flexible operation e.g., a high ramping event, when most CCGTs are operating in combined-cycle mode. There is also a higher peak utilization of hydropower generation as VRE generation increases. The generation during peak periods changes as the share of VRE generation increases, especially as a large amount of CCGT generation is displaced by wind and solar PV.

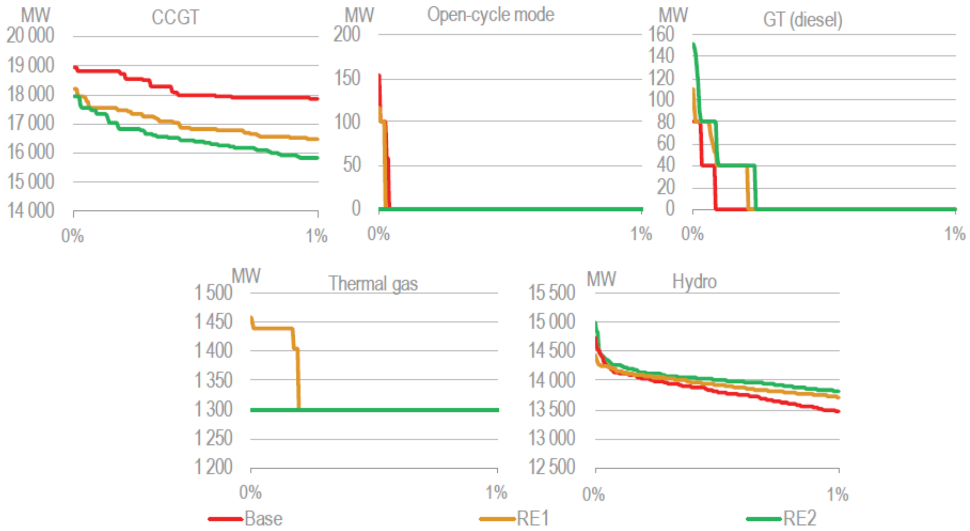


Figure 21 GDCs of all technologies in the top 1% for different VRE scenarios.

It should be noted that this result would be expected to change in a system with an optimized capacity expansion with full consideration of all available demand- and supply-side resources, including VRE generation. Moreover, [6] states that VRE generation reduces the operating hours and capacity factors of dispatchable baseload power plants as those plants dispatch down in the presence of VRE. Regarding asset investment and retirement, favor low capital-cost non-VRE units over higher capital-cost units because of the expected decrease in capacity factors. Moreover, at high VRE penetration, VRE may be curtailed at light load times. When generation is lower than intended, it can be considered from two perspectives. Either the increase of the capital cost/MWh (specific capital cost) or the reduction of generators' revenue from selling less electricity than their capability [12, 14, 17-19]. These circumstances reduce the attractiveness of electricity generation investment because of the reduction in generators' revenue, while the investment is needed to ensure the security of supply [19, 25].

2.4.2 Changes in electricity market activities

According to [45], in a liberalized system, the electricity supply is differentiated into four functionalities, generation, transmission, distribution, and (retail) supply to final customers. Traditionally, generation was often connected to the highest voltage level and thus fed into the transmission network. While the holds true for large hydro and wind generation assets, medium- to small renewable energy generation assets, including wind, solar PV, biomass, and hydro, feed into the distribution network. Some large-scale consumers are connected directly to the transmission network. Most consumers are supplied via the distribution network.

While transmission and distribution are monopolies with regulated revenues, generation is a function with competition in wholesale markets; additionally, electricity trading and retail supply to customers can, but need not, be competitive functions. To enable secure supply, each system is governed by precise rules and dedicated institutions, which can vary in specific aspects but follow some basic patterns. Importantly, a designated system operator is responsible for the technically safe implementation of dispatch schedules that result from trade in markets where generators commit to delivering and users consume electricity. To that end, the system operator procures ancillary services from generators and users, normally in competitive markets. The liberalized systems' basic design choices consist of centralized and decentralized markets. The design choices are summarized as shown in Table 1. Centralized markets are used in some USA markets, Russia, Australia, New Zealand, Korea, Chile and other countries. While decentralized markets are used in many countries in Europe. Table 2 and Figure 22 show the electricity markets' general structure and timeline [46-49].

Table 1 The basic design choices of centralized markets and decentralized markets.

Centralized markets	Decentralized markets
In the day-ahead market, electricity generated is traded at a single market platform (The power pool)	In the day-ahead market, generators and suppliers are allowed to engage in any type of contractual obligations for the delivery of energy
Scheduling is centralized	Self-scheduling by generators
The market operator decides both on the (hourly) schedule of each unit and the price to be paid for energy using a central algorithm	- The market model does not require any central market operator but is essentially based on direct bilateral transactions between different market participants - The market is cleared based on a separate supply and demand curve, formed by the individual offers and bids for buying and selling electricity, respectively
Used in some of the U.S. markets, Russia, Australia, New Zealand, Korea, Chile, and other countries	Used in many countries in Europe

Table 2 The general structure of electricity markets.

	United States	Europe
Structure	• Build into existing system operators (ISOs) • Emphasize the physics of the power system • Short-term system operation • ISOs do not own transmission system	• Introduced new power exchanges (PXs) • Emphasize markets and economics • Includes long-term contracts • TSOs typically own transmission system
Type of markets	• Forward Capacity Market • Day-Ahead Energy Market • Real-Time Energy Market • Ancillary Service Market • FTR Market*	• Forward market • Day-ahead market • Intra-day market • balancing market
Market design	• Complex bids/ISO unit-	• Simple bids/generator

	United States	Europe
	commitment • Locational marginal prices • Co-optimization of energy and reserves • VRE is dispatched	unit-commitment • Zonal pricing/market coupling • Sequential reserve and energy markets • VRE is must-take

*FTR markets, also called transmission congestion contracts and financial congestion rights, are markets designed to hedge the volatility in locational differences of energy pricing

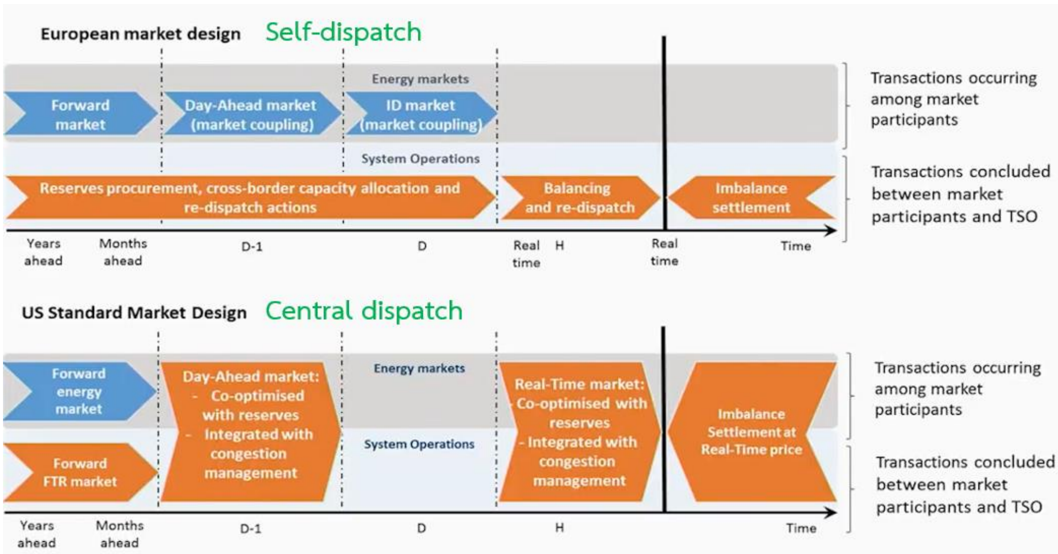


Figure 22 Market timeline.

VRE generation poses impacts on electricity market activities because, in energy markets with the current market design, the MP at a specific time is the MC of the last power plant needed to meet the electricity demands at that time. Among all generators offering their energy to the markets, VRE generators are prioritized because of their low MC. When VRE generators supply their output into the markets, the most expensive generators on the markets are driven out, and the MP is diminished. The greater the VRE output, the greater the drop in MP. Moreover, VRE generators often supply electricity with no regard for demand because of their non-dispatchable characteristics. The output could highly exceed the demand during windy or sunny hours, contributing to very low MP (possibly zero or even negative). That means VRE output affects the MP quantity and distribution during the day. Inflexible generators that use low bids to avoid startup/shutdown costs can increase price suppression. This circumstance is called the “merit-order effect” (MOE). Any generators in energy markets gain their revenue based on MP; thus, MOE contributes to reductions in generators’ revenue [6, 7, 12-22].

Many studies confirmed that MP is declined by VRE penetration and its output. Research [78] found that the MP was decreased around 0.63 $/MWh in Germany and 0.95 $/MWh in Spain per additional percent of wind infeed. In the case of Italy, [79] proved that 1 GWh from solar and wind reduces the average MP by 2.73

$/MWh and 4.99 $/MWh, respectively. In the United States, research [20] found that the average load-weighed MP for each additional percentage of VRE penetration declined by 0.2–0.9 $/MWh (CAISO, NYISO, SPP, and ERCOT), similarly to [6], in which case it was 0.1–0.8 $/MWh (CAISO and ISO-NE). Research [80] indicated that European wholesale electricity prices had dropped by nearly two-thirds since their all-time high in 2008. The largest factor depressing the prices was the expansion of VRE. VRE is expected to become competitive in energy markets. However, the competitiveness might not be enough to ensure profitability on energy markets if the MP falls too low [81]. In terms of other markets, greater variability in energy market prices creates more variations between day-ahead and real-time prices growing ancillary service needs and higher ancillary service prices. Moreover, generators can offer their capacity into capacity markets. Thus, there will be a tendency towards greater revenue from ancillary service markets, from capacity markets (where they exist), and/or from scarcity events [6]. However, there is no garuntee that every generator can recover their costs from all markets as especially when MOE is servere.

Many countries provide support schemes for RE generation to reach their RE targets. The schemes are not only provided to VRE generators, but also other RE generators, such as biomass and hydro plants, but this dissertation focuses on the support provided to VRE generators. The schemes help cover the cost disadvantages faced on liberalized electricity markets [50]. However, the schemes involve prices VRE generators have offered to the markets [36]. Lower bid prices will yield lower overall prices when those bids are on the margin [6]. Thus, the support schemes unintentionally affect MP and probably make MOE more severe.

The common support schemes are feed-in tariff (FIT), contract for difference feed-in tariff (CFD-FIT), and feed-in premiums (FIP). These support schemes have been applied in 23 out of 27 EU countries [51], and many other countries around the world. The approaches of the schemes are as follows:

- Feed-in Tariff (FIT): Generators receive a fixed price per kWh for each unit of electricity generated, differing according to the generation sources (wind, solar, etc.) [50]. The fixed prices, which are independent from the MP, are mostly determined by the government. This means that generators do not receive any revenue directly from the markets [52].
- Contract for difference feed-in tariff (CFD-FIT): Generators receive a fixed price per kWh for each unit of electricity generated. The price called the “strike” price or “reference” price is established by the government through bidding. At a specific time, generators sell their energy at the MP that can be above, below, or the same as the strike price. If the MP is equal to the strike price, then there is no further action. If the MP is below the strike price, generators will get payment on top of the MP to reach the strike price. If the MP is above the strike price, generators have to pay back the difference [52, 53].
- Feed-in premiums (FIP): Generators receive the MP from the market and an additional fixed payment per kWh on top of the MP. The fixed payment could vary according to the associated risk sharing between the generators and the public [52].

The differences in support schemes are shown in Figure 23. FIT and CFD-FIT-supported generators receive fixed revenue regardless of the MP. FIP-supported generators' revenue depends on the MP at a specific time. In energy markets, generators need to ensure that they will be committed to selling energy; thus, they will offer the lowest prices they can accept without loss. Supported VRE generators will offer negative prices equal to the support prices they receive, and VRE generators without support will offer their MC [36]. Figure 24 shows the use of support schemes by countries [51, 54-61]. Note that there is the FIT scheme in Ontario, Cannada.

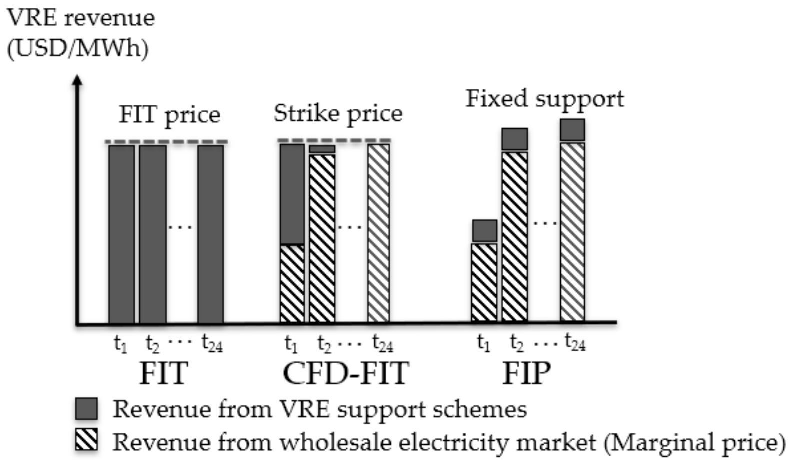


Figure 23 The differences among the support schemes.

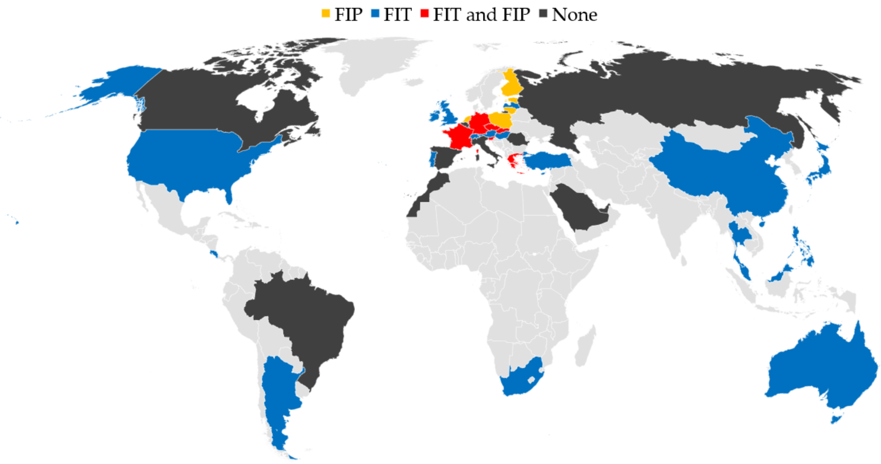


Figure 24 The use of support schemes by countries.

Chapter 3

Evaluating the impacts of VRE integration

The impacts of VRE integration have been confirmed in many studies, as reviewed in the previous chapters. Electrical system planners and policymakers should assess the systems' technical and economic aspects before setting system plans and policies. In monopolized markets, such assessments are done by utilities to guide investment into generation. In liberalized markets, the assessments are essential for making rules and regulations to incentivize investment that aligns with policy goals [4]. This chapter presents a comprehensive explanation of VRE integration costs in Section 3.1. Section 3.2 approaches for determining the impacts of VRE integration on total system costs. Section 3.3 provides approaches for evaluating VRE impacts on electricity generation revenue.

3.1 Variable renewable energy integration costs

Integration costs are caused by interactions between integrated generators and established electrical systems [13]. These interactions consist of both technical aspects, i.e., maintaining SPCs and SOCs, 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 its electricity 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]. High VRE penetration in electrical systems leads to sophisticated and uneconomic system operations. Using utility-scale energy storages to stabilize VRE generation is costly as present technologies. Moreover, energy storages gain interest mostly on the residential scale [82]. This dissertation categorized integration costs as direct integration costs and indirect integration costs.

3.1.1 Direct integration cost

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, 83].
- 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 ramp capability, frequent cycling, and part-load operation, to compensate for variations in VRE generation (profile costs count only scheduled operations; unscheduled operations from forecast errors are counted as balancing costs) [12].

3.1.2 Indirect integration cost

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 [84]. 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 [85]. Second, VRE can supply electricity uncorrelated with demand because of its non-dispatchable characteristics. Therefore, during particularly windy or sunny hours, MPs can be very low (possibly zero or negative), i.e., the “merit-order effect” [15, 19-21, 86]. It is important to consider these price variations [75] because any generators participating in energy markets gain their revenue based on Marginal prices. 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.

Undoubtedly, Integration costs increase electrical system costs and grow with RE generation penetration. In [25], the comparison of a cost-optimal system and a clean-energy system in terms of costs was provided. The research showed that there was 0.38 cent/kWh addition from a cost-optimal system price to reach the RE integration target of Mexico and let Mexico’s electrical system become a clean-energy system. The summation of possible integration costs from research [12] is 32.1 Euro/MWh (2015). According to [87], Germany's electricity prices for household consumers in 2015 were around 143 Euro/MWh. It means that integration costs are possibly over 20% of the electricity prices [12, 87]. Therefore, 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, 80, 88, 89]. 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, 90-92]. Figure 25 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. They indicate the possibility that providing residual load in a system with VRE generators is more expensive than in a system with only conventional generators. Table 3 shows the reviews of integration costs collected from the literature.

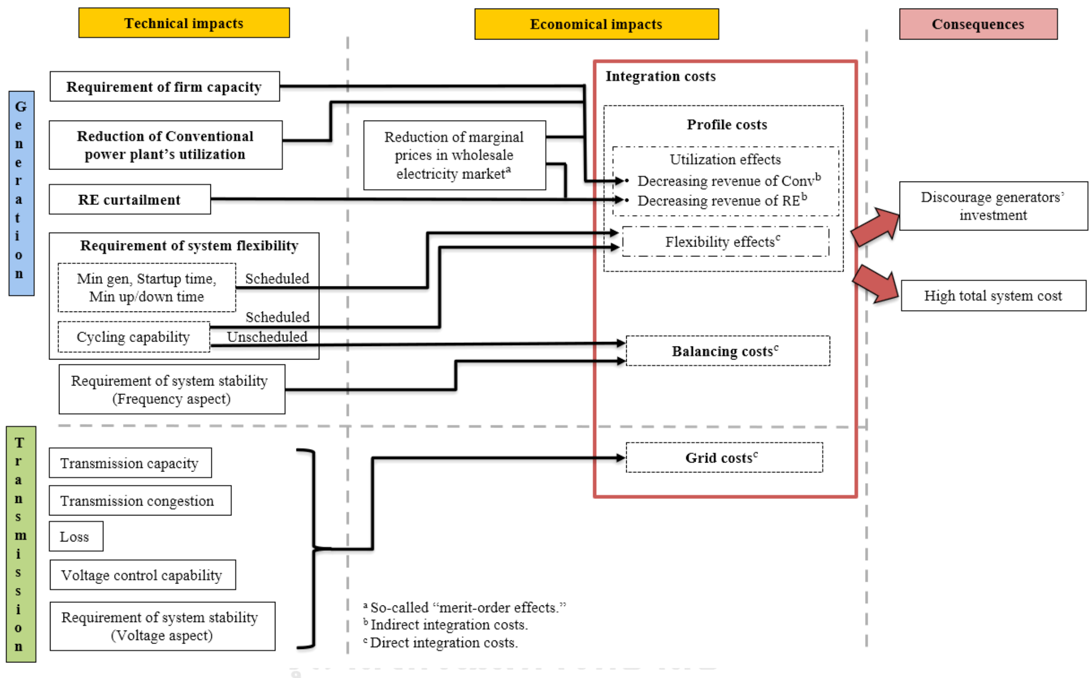


Figure 25 The impacts and consequences of integration costs.

Table 3 Reviews of integration costs.

Ref.	Technology (% market shares)	Balancing costs	Grid costs	Profile costs
[12]	Wind (30-40%)	< 7.2 \$/MWh	0.12-1.32 \$/MWh	18-30 \$/MWh
[17]	-	2.4-6 $\text{\$/MWh}_{IRES}$	2.9-3.7 €/MWh_{IRES}	3.6-9.6 $\text{\$/MWh}_{IRES}$
[18]	Wind, Solar (20-26%)	3.2-3.5 \$/MWh	4.5-5.8\$/MWh	5.8-9.6 \$/MWh
[8, 12]	Wind (20%)	0.69 \$/MWh	1.23 \$/MWh	-
[12, 67]	Wind (0-40%)	1.2-4.8 \$/MWh	-	3.6-25.2 \$/MWh
[9]	Wind (20%)	1.2-5.4 \$/MWh	-	-
[7]	-	-	6 $\text{\$/MWh}_{IRES}$	
	Wind, Solar (50%)	-	-	6-32.4 \$/MWh

GBP/USD is 1/1.37 and EUR/USD is 1/1.2 040221.
MWh_{IRES} is generation from intermittent RE sources (IRES).

3.2 Evaluating impacts of VRE on total system costs

There are many types of VRE integration analysis. According to [93], All grid integration studies are unique. Each study is tailored to address the concerns most relevant to a given power system. A grid integration study generally involves modeling the power system using approaches that fall into one or more of three general categories: capacity expansion, production cost, and power flow. A best-in-class grid integration study uses all three types of analyses; however, many grid integration studies focus only on one or two methods. In subsequent chapters, this guidebook emphasizes production cost modeling (sometimes called dispatch modeling) as a central component of a grid integration study. Production cost modeling enables an assessment of the costs and impacts of increased variability and uncertainty from weather-driven generation resources (such as wind and solar) in power system operations. Other analyses, including capacity expansion and power flow modeling, can address additional questions. Power system planners and operators may also use all three types of analysis outside the RE integration context. The choice of which analysis or combination of analyses to implement depends on the policy-relevant questions that best address a country's priorities. For example, if planners are in the process of evaluating the optimal energy supply mix to meet long-term policy goals, a capacity expansion analysis that focuses on generation and transmission build-out may be most valuable, especially if it is complemented by production cost analysis to test the operational impacts of various expansion scenarios. On the other hand, if power system planners and operators are seeking to prioritize the near- and medium-term actions they can take to improve the flexibility of the power system, production cost analysis may provide the best framework. Power flow modeling can be the most relevant approach to address concerns from the system operator about the reliability implications that high variable RE scenarios might pose to the electricity grid. Figure 26 illustrates the iterative relationship among capacity expansion, production cost, and power flow analyses, including how each type of analysis can inform the others. Regardless of the type of analysis, implementation of known effective solutions, data collection, and modeling expertise are prerequisites that enable an impactful integration study

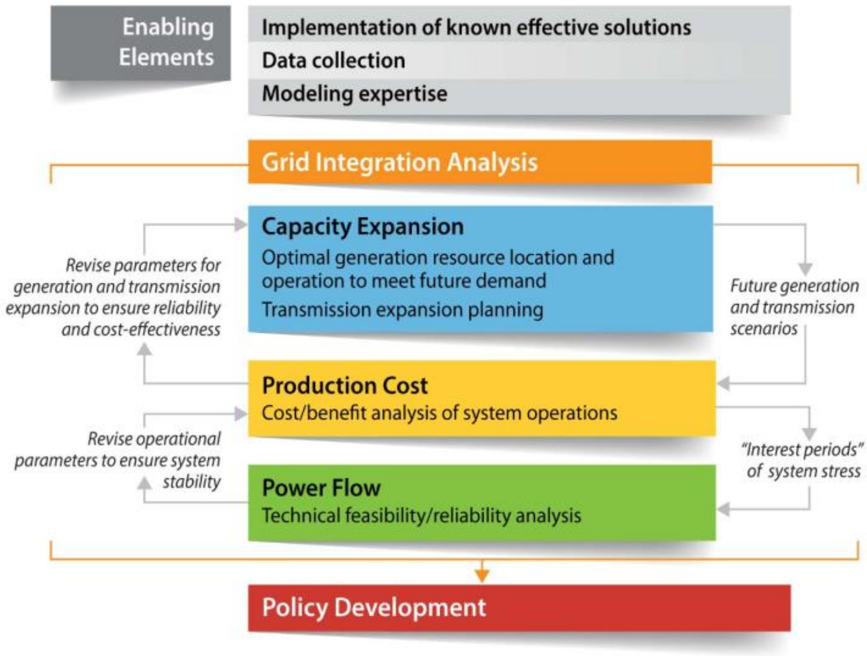


Figure 26 Types of and relationships among different analyses of a grid integration study.

1. Capacity Expansion Analysis

Capacity expansion analysis identifies where, when, how much, and what types of generation and/or transmission resources can provide reliable electricity supply at least cost, considering new policies, technological advancement, fuel prices, and demand projections. In many power systems, capacity expansion analysis forms the basis of developing a power sector master plan or integrated resource plan. Capacity expansion analysis is based on models that optimize the least-cost generation and transmission capacity mix. Grid integration studies use capacity expansion analyses to inform the type, amount, timing, and geographic placement of solar and wind generation capacity (as well as other generation and transmission resources) needed to achieve RE or other policy targets.

• Modeling horizon: medium- to long-term horizons (such as 20-50 years)

• Temporal resolution: Annual for each year within the modeling horizon, with the representation of seasonal constraints and reduced-form intraday constraints

• Key inputs: high spatial resolution data on RE resource availability; annual electricity demand and projections; capital costs of generation technologies; fuel price projections; generation and transmission investment constraints; and operational constraints

• Example applications:

o Identify cost-effective installed capacity and locations for variable RE and conventional generation

o Evaluate the impacts of energy and climate policies on future systemwide costs, emissions, fuel consumption, and economic development indicators o Identify cost-effective transmission system upgrades and expansion—including trade-offs between transmission and generation expansion

o Assess systemwide capital costs associated with one or more generation or transmission expansion plans

o Inform production cost studies by identifying and prioritizing generation and transmission buildout scenarios—including installed variable RE capacity and siting

o Examine the role of various technologies, such as energy storage in integrating variable RE

o Assess long-term, systemwide trends in the decarbonization of the power sector

2. Production Cost Analysis

A production cost analysis assesses the impacts of one or more variable RE penetration scenarios on bulk power scheduling and economic dispatch. Production cost analyses focus on minimizing the operational cost of different future scenarios; the analyses do not evaluate capital costs of new generation or transmission assets.

• Modeling horizon: One future year (usually 10-20 years in the future)

• Temporal resolution: Hourly to sub-hourly (such as 30- minutes or 15-minutes) unit-commitment and/or dispatch intervals

• Key inputs: Time-synchronous demand and RE generation data; detailed system characteristics such as generator ramping and minimum generation capabilities, fuel and other operational costs, transmission system attributes, and emissions restrictions

• Example applications:

- Evaluate the feasibility of high RE penetrations from an operational perspective by assessing RE curtailment levels, generator ramping, plant load factors, reserve requirements, reservoir, and pumped storage management requirements, emissions, fuel consumption, transmission constraints, and operational costs associated with different RE scenarios and flexibility options

- Test institutional and physical options for improving system flexibility to support high RE penetrations, and quantify the future operating costs associated with these options

- Test the operational impacts of capacity expansion scenarios and provide feedback to help adjust capacity expansion analyses

- Identify "periods of interest" (such as high RE/low load and/or low RE/high load) that may require further stability testing through power flow analyses.

3. Power Flow Analysis

Power flow analyses—including load flow simulations and dynamic stability analyses—test the stability of the transmission system under different RE penetration scenarios. For instance, these analyses can assess the ability of a power system to respond both under normal conditions and when a real-time disturbance such as an unplanned generator or transmission line outage occurs. Depending on their focus, power flow analyses model real and reactive power flow, fault tolerance, and frequency response over very short timeframes that correspond to periods of system stress. Evaluation of costs and economics is not usually a component of this type of reliability analysis.

• Modeling horizon: Several minutes, corresponding to periods of system stress

• Temporal resolution: Seconds to minutes

• Key inputs: RE generation profiles at discrete sites; details about generators' ability to respond to contingencies, transmission line impedances, transformer details, and tap settings

• Example applications:

- Verify the technical feasibility of high RE penetrations in terms of reliability parameters, such as magnitude and duration of frequency deviation following a disturbance (including system recovery time), fault tolerance, voltage stability, network branch loading (congestion), short circuit levels, and contingency response

- Inform system operators about mitigation measures to keep system voltage and frequency within reliability parameters during normal- and high-stress periods

- Serve as a reliability check for production cost scenarios

- Determine whether different RE deployment scenarios meet grid code requirements.

Table 4 provides examples of questions addressed by different types of grid integration analyses.

Table 4 Examples of Questions Addressed by Capacity Expansion, Production Cost, and Power Flow Analyses.

Type of study	Example questions addressed
Capacity Expansion	• Where, when, how much, and what types of infrastructure (generation and/or transmission) would achieve VRE targets at least cost? • How will factors such as new policies, technological advancement, fuel prices, and electricity demand growth affect future planning for generation and transmission infrastructure? • What are the systemwide capital costs associated with different VRE targets? • How will different VRE penetration scenarios impact economic development indicators? • What are the expected air emissions reductions associated with VRE scenarios? • What types of generation and transmission infrastructure can protect the power sector against unexpected disruptions to the

Type of study	Example questions addressed
	normal operations of a system?
Production Cost	• What impacts do VRE penetration scenarios have on bulk power scheduling and economic dispatch? • What are the expected VRE curtailment levels, GHG emissions, generator ramps, plant load factors, reserve requirements, transmission constraints, and other generator-level impacts under different VRE scenarios? • What are the relative systemwide operating impacts associated with different VRE expansion scenarios (such as different levels of VRE, siting of VRE in best resource sites versus close to transmission lines)? • What are the cost-effective mechanisms to access flexibility (e.g., from institutional measures such as forecasting or new infrastructure such as transmission) under high VRE penetration levels?
Power Flow	• How do high penetrations of wind and solar impact the transient stability and frequency response of the electric power system? • Do VRE scenarios meet the security or reliability criteria for the power system? • Can the power system sustain and recover from temporary and significant disturbances with high levels of nonsynchronous generation? • Will VRE deployment scenarios meet grid code requirements? If not, what interventions may be necessary? • How does the power system respond to a real-time disturbance such as an unplanned generator and/or transmission line outages under various VRE deployment scenarios? • What is the expected system recovery time (i.e., magnitude and duration of frequency deviation following a disturbance) under various VRE deployment scenarios?

According to [4], in addition to securing generation adequacy in a power system, by ensuring sufficient firm capacity exists to meet demand, long-term transition planning also must ensure that enough flexibility is present to address fluctuations in demand and in VRE. High penetration levels of VRE are likely to increase the variability that the rest of the system will need to accommodate and at a shorter time scale (i.e., less than an hour upwards). Long-term generation expansion models are not typically designed to capture balancing needs at a sub-hourly level. If long-term investment decisions ignore such needs for flexibility, they tend to underestimate the value of investments in flexible power plants and other system services. This results in a long-term energy mix that is potentially both economically and technically inefficient. This chapter discusses three kinds of solutions to overcome the common limitations of representing flexibility in long-term energy planning models.

Incorporating flexibility constraints: A system's flexibility can be represented in generation expansion models by first parameterizing the ranges of operating flexibility (e.g., minimum load levels and cycling speed) for "flexibility provision" options – including dispatchable plants, storage, demand response, and cross-border trade. Ramping requirements associated with the variabilities of demand and of VRE can be assessed separately and balanced collectively with available flexibility options at an aggregated system level. Using this "flexibility balance" approach, models can optimize investment in flexibility options to meet system requirements as an additional constraint to the standard balancing of total power demand and supply.

General complexity: Low to medium

Validating flexibility balance: As an alternative to, or in addition to, incorporating flexibility constraints, results from generation expansion planning models can be further scrutinized using more detailed tools with different degrees of complexity. Such validation tools scrutinize operational aspects of a power system and give high-level indications about whether the energy mixes resulting from generation expansion planning models would offer sufficient flexibility.

General complexity: Medium to high

Linking with production cost models: Production cost models can be used to validate results from long-term generation expansion models or to correct such results if necessary. Such a "coupling" approach can translate a system's needs for flexibility in operation (a focus of production cost models) into decisions around investment (a focus of generation expansion models).

General complexity: High

Article [94] proposed the method to minimize the total costs of power generating units' construction and operation in the long-term horizon. The costs are divided into fixed costs and variable costs. The fixed and variable costs represent the typical approach for energy mix optimization with distinguished optimization of power capacity and energy generation. They combined the long-term planning with the short-term operation of power units. Adding the costs of the commitment and dispatch for single hour to the objective function is an artificial modification. The objective function still represents the costs, and the modification applied can be considered as a transformation of the three-dimensional problem (cost of capacity, cost of annual generation, costs of hourly operation) to the dimension problem, which value can be calculated, compared and subjected to minimization. The authors precisely investigated that additional elements in an objective function before posing constraints on dispatch do not affect long-term planning.

To determine system planning relevant to VRE such as finding optimal VRE penetration, various criteria have been used such as cost minimization, CO_2 emissions minimization, land use minimization, employment maximization, and Energy Return on Energy Investment (EROI) maximization [62]. However, the system planning under all priorities is a very ambitious goal, plus, it is difficult to prioritize the importance of each priority in order to find the optimal point while satisfying all constraints from all criteria. That is why many pieces of research choose one or two criteria to form the optimization model. Technical-economic is the approach that is frequently used, for instance, in [63-65]. Using techno-economic criteria allows all the essential aspects of the power system, i.e., system operation, system reliability, and integration costs, are considered. In addition, if the model is developed under both criteria, it is possible to expand the model's scope to make it considered under other criteria. For example, CO_2 criteria can be included if the volume of CO_2 is changed into carbon price.

Moreover, the dynamic programming approach is applied to the electrical system planning process to determine the least cost generation plan based on the key factors including capacity costs, fixed operation and maintenance (O&M), and outage costs. For example, in Thailand, the Thai officials responded that the ABB STRATEGIST software was the tool being used for planning purposes. The software determines the new generation capacity requirements of the system. It applies probabilistic techniques for forced outages of generating units. The flowchart of the tool is shown in Figure 27 [18].

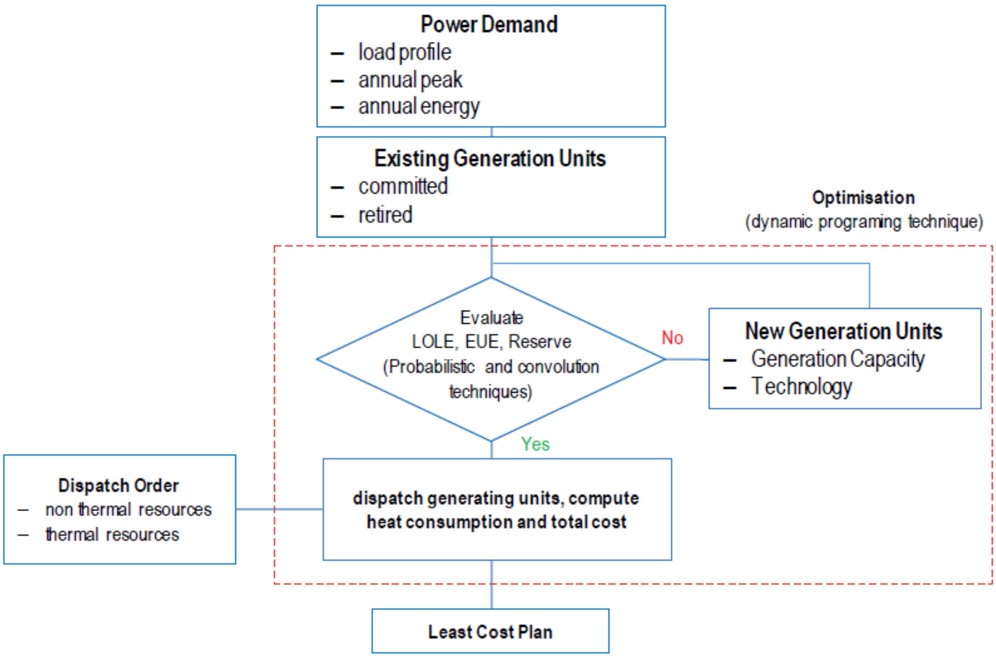


Figure 27 Flowchart of generation expansion model, as used by EGAT.

Note: EUE = expected unserved energy.
Source: Provided by EGAT [18].

However, the description of the tool from the vendor clarifies that it is not suited for performing short-term analyses, studies requiring high levels of operational detail (which is important as the share of VRE increases), and studies requiring the modeling of the primary power plant operational characteristics, such as ramp rates or start-up costs. Given that integrating large shares of VRE into the system requires planners to take into account a range of operational power plant characteristics (e.g., ramp rates) and associated costs (e.g., start-up costs), supplementing the planning process with a different or additional type of tool is required in order to make assessments more suited for VRE. In addition, the software should be consistent in short-, medium- and long-term planning. Approaching high penetration of VRE requires more sophisticated planning tools that can also integrate across various power system timescales [18]. Moreover, integration costs are essential for system planning and policymaking. Ignoring or underestimating them leads to biased conclusions about the welfare-optimal generation mix and system transformation costs [4, 12, 13]. Planning methods for VRE integration that integrate all costs and derived effects are needed [24, 31-34].

According to [18], an assessment of its system-level economic effects is necessary to understand the economic impacts of integrating VRE into an electrical system. Generation cost for various technology options is most expressed in the Levelized cost of electricity (LCOE), representing the average lifetime cost for providing a unit of output (MWh). However, the LCOE approach does not account for some crucial aspects of power generation, particularly the technology's timing, location, intertemporal aspects, and operational characteristics. Therefore, particularly to evaluate VRE, additional metrics that account for the interactions between these power plants and the rest of the power system can be employed.

Adding VRE will trigger two different groups of economic effects in the electrical system:

• **An increase in some costs:** This includes the cost of VRE deployment itself (i.e. the LCOE), costs for additional required grid infrastructure, and/or increased costs for providing balancing services. This group can be termed system costs or additional costs.

• **A reduction in other costs:** Depending on circumstances, cost reductions might occur due to reduced fuel costs for conventional generators, reduced carbon dioxide (CO2) and other pollutant emissions costs, a reduced need for other generation capacities, a reduced need for transmission infrastructure, and/or reduced transmission system losses. This group can be termed benefits or avoided costs.

Three different ways to express system effects

• **System cost analysis**: The addition of VRE capacity is often compared to alternative forms of new generation, such as CCGTs or coal plants. This approach calculates the system effects associated with VRE compared to other generation options; it can be helpful for comparing different technologies to each other. For the calculation of system costs, the impact of reducing full-load hours of existing generators is not taken into account. Instead, a comparison is made between adding the reference technology, for example, CCGTs at 80% capacity factor, and adding VRE plus the amount of backup capacity needed to provide the same firm capacity. This analysis can help inform the question: “Is it cheaper to build a CCGT or wind/solar?” but not the analysis question: “Should we build anything at all?”

• **Cost-benefit assessment**: Adding up all additional and avoided costs indicates the overall cost-benefit of adding VRE. This comparison is useful to understand whether adding VRE can help reduce customer bills. Note that this comparison only covers the economic impacts of VRE integration and does not include other factors, for example, the reduction of CO2 emissions. System value is defined as the overall benefit from adding a wind or solar power generation source to the power system; it is determined by quantifying positive and negative impacts on the system and summing them together. This system value can then be compared to the generation cost of VRE. This cost-benefit comparison answers the question of whether adding a certain technology to the system brings more benefits than costs. If the system value is larger than the generation costs of VRE, there will be a net benefit. Conversely, if the system value is lower, there will be a net cost. This approach can analyze the effect of adding VRE capacity (or any other technology) to the system compared with any alternative scenario, including the option of not building any new generation.

• **Total system costs**: The all-encompassing method to account for all relevant system effects is to calculate total system costs, including capital and operational costs for different scenarios with varying amounts of VRE. It provides insight into the total costs of low and high VRE cases. Using this approach, the analysis estimates the impact of VRE penetration and flexibility measures on the long-term cost of the electrical system.

Regarding setting VRE plans and policies, policymakers must focus on overall costs to determine an optimal system plan and policy options that compile all costs and effects incurred in the system. Electrical system planners and policymakers should assess the systems' technical and economic aspects 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]. For this purpose, the “total system cost approach” is more appropriate. The total system cost approach can establish the optimal generation mix to meet the electricity demand at the lowest costs. The approach allows for evaluating the costs incurred in electrical systems from all generators and avoids the controversy over cost allocation to a specific kind of generation technology [5, 7]. The approach detailed in Figure 28 may be applied to compare a scenario with a high share of renewable energy to one with a low share of renewable energy. A straightforward comparison of the total system costs is possible between the two scenarios. Optionally, one can also analyze the interaction effects and attribute different cost components to other technologies. For example, cost reductions (fewer fossil fuel imports, lower investment needs in thermal power plants) and cost increases (investment in renewable capacity, new grids) can be identified by comparing the scenarios. Yet these optional analyses and assumptions on cost causation are not necessary for the analysis of different pathways.

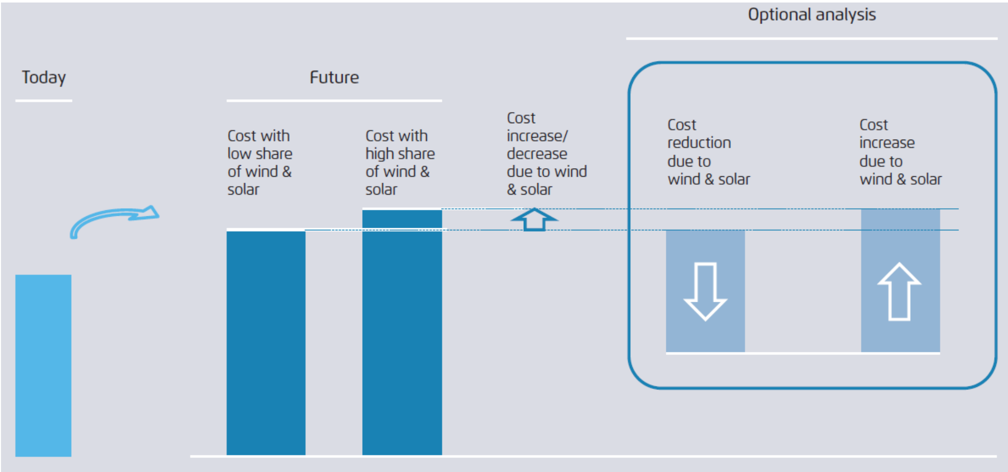


Figure 28 Total system cost approach for comparing different VRE penetration scenarios.

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; 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 SPCs and SOCs, and economic aspects, i.e., minimizing total system costs [5-7, 95]. Complex computer models (or combinations of models) are used to simulate dispatch and capacity expansion and assess the combination of resources that best minimize total system costs [6]. The UCP is frequently used to set the models [12, 17, 18].

According to [41], 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. The UCP can be applied to both centralized and liberalized market systems. Dynamic programming (DP), genetic algorithms (GAs), and mixed-integer programming (MIP) are generally used to solve the UCP. These methods can cope with the non-convexity of fuel curves, ramping constraints, and generation technologies' minimum uptime/downtime constraints. MILP can also be used if non-convexity constraints are simplified to a piecewise linear function [40, 41].

In consonance with research [42], one of the potential key issues in the quality of electricity planning 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 typical days (semi-dynamic approach), and the very high time resolution (fully dynamic approach).

- Integral method: The integral balance method, as it is called here, is often used to balance electricity demand and supply in mid/long-term planning tools. This method represents the electricity demand in a load duration curve (LDC) and matches the needs represented by the curve with the available supply options, following a dispatch rule. The LDC is generally divided into some time-slices (varying, in the majority of the cases, from 5 to 10 time-slices) in order to represent the different electricity needs over a period of time (e.g., a year). Since the curve is organized from the highest power values to the lowest ones, the time slices will represent an average of the power demanded in a fraction of the year (e.g., in this work, the LDC is divided in 9-time slices, with 8 time-slices of 1000 h and 1 with 784 h). With the time slices defined, the next step is to fulfill the power demand needed for each time slice with the available resources in the supply, which are generally defined by a capacity factor over the installed capacity. The advantages of this method are its simplicity and the fact that not so much data is needed for the LDC or to characterize the resources on the supply side. However, this method does not consider the real time-dynamics from the demand and the supply that are lost due to the time and power aggregation to build the LDCs power/time-slices. Another simplification is using an average capacity factor to represent the availability of the resources at the supply side, with an effect on the renewables that lose their intrinsic power variations to a constant power value.

- Semi-dynamic method: The semi-dynamic balance method used in this work was designed to try to capture some of the electricity supply and demand dynamics by using only selected typical days to represent the power variations along the year instead of using all days in a year (as used for the dynamic method). The idea behind this method is a compromise between having some dynamics and at the same time being less data and processing intensive for the mid/long-term planning tools. For example, the software 'TIMES' was used in [42] to perform the calculations using the semi-dynamic balance method. Here, each year is divided into four seasons, three days per season (Wednesday, Saturday, and Sunday), and 24 h each day, giving a total of 288 time periods per year. The time periods representing hours from weekdays account for five times a single hour from a Saturday or a Sunday. The model then has 12 load curves of average days, which can then be used to balance supply and demand while taking into account some seasonal, daily, and hourly dynamics.
- Dynamic: The dynamic balance method, as it is named here, is mostly adopted to balance the electricity needs with the available supply options in short-term planning tools. These tools usually consider one year or less to do the balance, such as HOMER or EnergyPLAN, instead of a sequence of years (an evolution from the base year to the final projected year). This method consists in representing the electricity demand in an hourly load curve for a period, which can range from a day to a few years, where all the hours, or a smaller time-step, must be represented in the same sequence as they happen (e.g., every full hour of a specific day). As the demand, the supply must also be characterized on at least an hourly basis, with the expected availability of each resource. Having both demand and supply resources evolutions on the same time basis, the next step is to match each hourly demand needs with the available supply, which is to be done respecting a predefined dispatch rule. This method requires much more detailed data than the integral method to characterize demand and supply, especially if the aim is to use it for the long-term, but in compensation, it copes with all the possible dynamics that may

occur. In [42], EnergyPLAN was used to perform the dynamic balance method calculations.

3.3 Evaluating impacts of VRE on electricity generation revenue

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 generator investments, which are indirect integration costs, as mentioned above. Although generators might make profits from other markets [90-92] or use market power to gain more revenue [77], the policies' support can encourage investment and 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

Electricity prices are the main factors determining VRE's impact on electricity markets. The market value of VRE will be measured as its relative price compared to the base price. Research [15] calls this relative price "value factor". The value factor is calculated as the ratio of the hourly wind-weighted average wholesale electricity price and its time-weighted average (base price). Article [15] provides the classification of the approach used to estimate electricity prices: historical market prices, shadow prices from short-term dispatch models, or shadow prices from long-term models that combine dispatch with endogenous investment.

- Historical market prices: collect hourly electricity prices and synchronous VRE in-feed. The drawback of this approach is that results are limited to the historical market conditions, especially historical penetration rates.
- Shadow prices from (short-term) dispatch models: To derive value factors under conditions other than those which have been historically observed, electricity prices can be derived from dispatch models. However, since the capacity mix remains constant by definition, pure dispatch modeling does not account for changes in the capital stock triggered by higher VRE penetration. Thus, historical market data and dispatch models can only deliver estimates of the short-term market value of VRE. The models applied in the literature vary starkly in terms of sophistication and temporal resolution.
- Shadow prices from (long-term) dispatch and investment models: Introducing significant amounts of wind and solar power to the market alters the structure of electricity prices and incentives investors to react by building or decommissioning power plants. To consider investor

response to VRE and to derive long-term value factors, one needs to model investment endogenously.

Research [66] uses a sophisticated European electricity market model to estimate the wind and solar value factors in Germany. The research reports them to drop from rough unity to 0.7 as installed capacities increase to 35% and 9% market share, respectively. Research [67] applied a similarly elaborated mid-term model to California, finding comparable results: the wind value factor drops to 0.7 at 40% penetration. Since electricity demand for cooling is better correlated with solar generation, the solar value factor is higher in California than in Germany. However, it drops similarly dramatically with increased solar shares, despite the flexible hydro capacity available in California dampening the value loss somewhat. Research [67] also models concentrated solar power and finds that thermal energy storage increases its value at high penetration rates. All results are summarized by [15] in Figure 29, Figure 30, and Table 5.

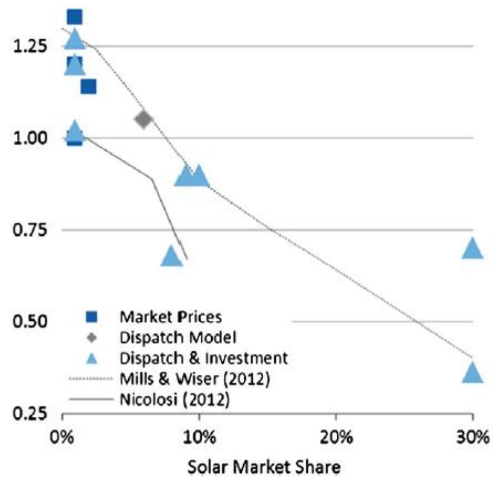


Figure 29 Solar value factors as reported in the literature.

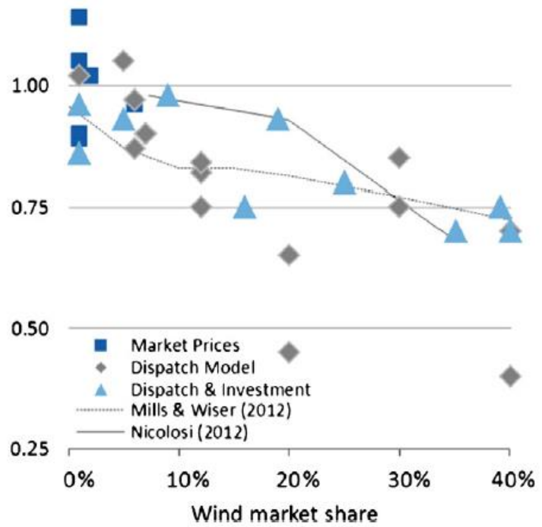


Figure 30 Wind value factors as reported in the literature.

Table 5 Empirical literature on the market value of VRE.

Price	Reference	Technology	Region	Value factor estimates (at different market shares)
Historical price	Borenstein (2008)	Solar	California	1.0–1.2 at different market designs (small)
	Sensfuß (2007), Sensfuß and Ragwitz (2011)	Wind	Germany	1.02 and 0.96 (2% and 6%)
		Solar	Germany	Solar 1.33 and 1.14 (0% and 2%)
	Fripp and Wiser (2008)	Wind	WECC	0.9–1.05 at different sites (small)
	Brown and Rowlands (2009)	Solar	Ontario	1.2 based on system price (small)
	Lewis (2008)	Wind	Michigan	0.89–1.14 at different nodes (small)
	Green and Vasilakos (2012)	Wind	Denmark	Only monthly value factors reported
Prices from dispatch model	Grubb (1991a)	Wind	England	Grubb (1991a) Wind England 0.75–0.85 (30%) and 0.4–0.7 (40%)
	Rahman and Bouzguenda (1994) Rahman (1990), Bouzguenda and Rahman (1993)	Solar	Utility	Only absolute value reported
	Hirst and Hild (2004)	Wind	Utility	0.9–0.3 (0% and 60% capacity/peak load)
	ISET et al. (2008), Braun et al. (2008)	Solar	Germany	Only absolute value reported
	Obersteiner and Saguan (2010) Obersteiner et al. (2008)	Wind	Europe	1.02 and 0.97 (0% and 6%)
	Boccard (2010)	Wind	Germany	0.87–0.90 (6–7%)
			Spain	0.82–0.90 (7–12%)
			Denmark	0.65–0.75 (12–20%)
	Green and Vasilakos (2011)	Wind	UK	0.45 (20%)
	Energy Brainpool (2011)	Onshore	Germany	0.84 (12%)
		Offshore		0.97 (2%)
		Hydro		1.00 (4%)
		Solar		1.05 (6%)
	Valenzuela and Wang (2011)	Wind	PJM	1.05 (5%)
Dispatch & Investment Model	Martin and Diesendorf (1983)	Wind	England	Only absolute value reported
	Swider and Weber (2006)	Wind	Germany	0.93 and 0.8 (5% and 25%)
	Lamont (2008)	Wind	California	0.86 and 0.75 (0% and 16%)
		Solar		1.2 and 0.9 (0% and 9%)

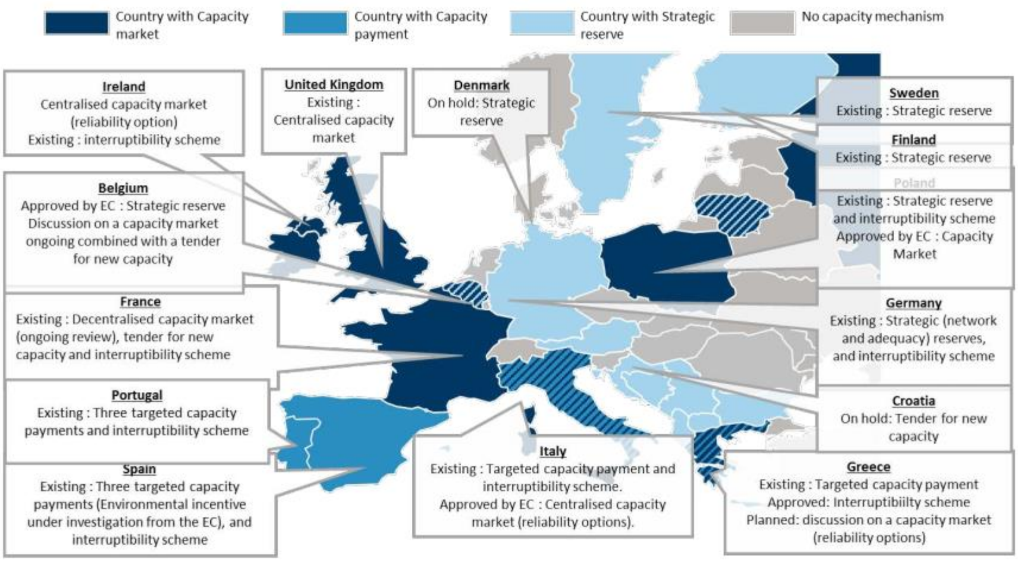
Price	Reference	Technology	Region	Value factor estimates (at different market shares)
	Bushnell (2010)	Wind	WECC	no prices reported
	Gowrisankaran et al. (2011)	Solar	Arizona	0.9 and 0.7 (10% and 30%)
	Mills and Wiser (2012)	Wind	California	1.0 and 0.7 (0% and 40%)
	Mills (2011)	Solar		1.3 and 0.4 (0% and 30%)
	Nicolosi (2012)	Wind	Germany	0.98 and 0.70 (9% and 35%)
		Solar	Germany	1.02 and 0.68 (0% and 9%)
		Wind	ERCOT	0.74 (25%)
	Kopp et al. (2012)	Wind	Germany	0.93 (19%) and 0.7–0.8 (39%)

Regarding capacity mechanisms, The three most important ones are strategic reserves, capacity payments, and capacity markets. What distinguishes the three schemes most clearly is the question of who sets the price of capacity and who sets the quantity being supplied. All schemes are used in some markets, but the current regulatory discussion mainly focuses on capacity markets. Table 6 compiles important information about capacity mechanisms [96]. Figure 31 shows the diversity of the capacity mechanisms introduced by the European Member States.

Table 6 Capacity mechanisms

	Strategic reserve	Capacity payment	Capacity market
Country	Finland, Germany, and Sweden	Ireland, Portugal, and Spain	The U.S.
Quantity (MW)	The regulator determines system critical power stations and pays these specific plants (Selection is mainly done by location).	The market will determine how much capacity is profitable to be supplied at the given price	The regulator sets the quantity necessary for generation adequacy and auctions that quantity in the market
Price of capacity	fixed costs set by the regulator (The regulator pays for the capacity of selected generators only)	A market-wide fixed price set by the regulator (all generators receive a fixed payment per MW installed).	The market sets the required price to provide the quantity needed to fulfill generation adequacy needs. (The regulator auctions the capacity required for generation adequacy annually)

	Strategic reserve	Capacity payment	Capacity market
Benefits	A very flexible measure that can be adjusted quickly by the regulator	Allows for the option of different payments per technology	Most focused towards fulfillment of the regulator’s goal to ensure the required capacity at the lowest possible price
Downsides	Strategic reserves distort price signals in periods of shortage, i.e., hindering investment in new capacity.	The risk that setting the price too low or too high leads to a lack of capacity or overcapacity	Significantly increases market complexity because it introduces an additional market that is interdependent with the electricity market.



Source: FTI-CL Energy

Figure 31 The diversity of the capacity mechanisms introduced by the European Member States.

Chapter 4

VRE impact mitigation

The VRE impacts on total system costs and electricity generation revenue are confirmed by many studies as presented in the previous sections. This chapter provides the VRE impact mitigation from both the electrical system's side, i.e., enhancing the flexibility of existing power plants in Section 4.1, and the market's side, i.e., bidding strategy in Section 4.2.

4.1 Enhancing the flexibility of existing power plants

System flexibility provided by dispatchable generation is one of the keys to integrating a high share of VRE into electrical systems. Following [35], the integration of renewable resources such as wind and solar increases variability and uncertainty in the electrical system. The flexibility of the electrical system may play a vital role in accommodating the variation in net demand that occurs at increased renewable penetration. The flexibility can come from several sources, including energy storage, demand-side management, or changes to market structures and operational practices, including increased cooperation across regional grid operators. Another crucial component of flexibility is the ability of traditional generation resources to change their output based on varying load, which is dictated by the parameters of minimum up/downtimes, ramp rates, and minimum generation level, along with start-up costs and part-load efficiency. Figure 32 shows the impacts of VRE at various time scales and relevant flexibility solutions [97].

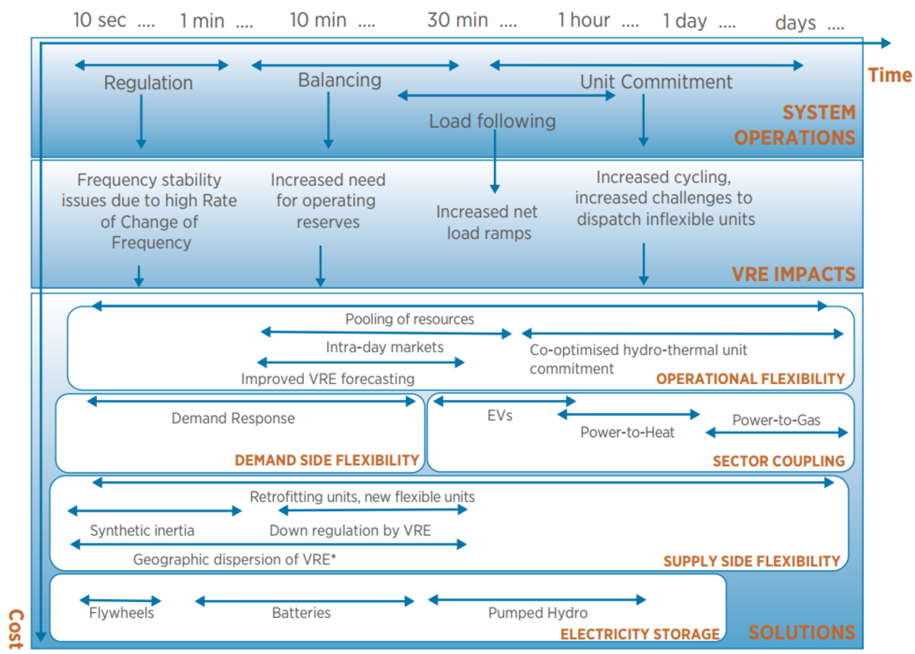


Figure 32 Impacts of VRE at various time scales and relevant flexibility solutions.

For example, research [36] states that although Germany's electrical system has a high penetration of RE generation, especially VRE, Germany's electricity system is one of the most reliable electrical systems in the world. The average duration of supply interruption has remained below 15 minutes per customer for several years. One of the main reasons that explain the ability of Germany’s electrical system is the system maintains sufficient dispatchable generation capacity to keep reliability while increasing the share of VRE. At the end of 2017, a total of 103 GW of conventional generation, i.e., nuclear, lignite, hard coal, gas, and pumped hydro, was available, plus 9.0 GW of bioenergy and 5.5 GW of run-off-river hydropower. All of the mentioned generation systems are dispatchable.

Some countries need to add more flexibility to their system to cope with VRE characteristics. For instance, research [18] concludes that the current electrical system in Thailand has a mixture of flexible and inflexible attributes. The generation fleet appears to be quite technically flexible, given a moderate share of hydropower and a high share of CCGTs, combined with an overall large reserve margin. The operating characteristics of CCGT and coal-fired power plants – particularly minimum generation levels, ramp rates, and start-up times – suggest that the current fleet’s flexibility could be significantly enhanced, as shown in Table 7. The inflexible operating characteristics result not only from the technical aspects but also the constraints under current PPAs. Because of the relatively high ramp rates and fast start-up times, hydropower generation is a highly flexible generation resource in Thailand. Hydropower is dispatched as peaking generation during high-demand periods. However, the minimum generation levels of these plants are very high, owing to irrigation requirements as well as to technical constraints such as turbine vibration. According to international standards, conventional technologies' minimum generation and start-up time appear to be high, while ramp rates are moderately low.

Table 7 Fleet-wide average operating parameters of conventional technologies in Thailand 2016.

Technology	Key operating parameters		
	Minimum generation (% of capacity)	Ramp rate (MW/minute)	Warm start time (hours)
CCGT	61%	20	6
Coal	55%	9	5.4
OCGT	55%	10	0.5
Thermal gas	47%	13	9.5
Hydro	75%	47	-
Hydro (imports)	85%	64	0.1
Diesel	34%	8	0.7
Fuel oil	27%	3	8

Sources by Electricity Generating Authority of Thailand (EGAT).

The critical operating characteristics of typical power plant technologies in Thailand’s system e.g., CCGT, coal, open cycle gas turbine (OCGT), and hydropower, are generally less flexible compared with the typical international average values of the same technology as shown in Table 8. This is particularly the case for minimum generation levels, which are relatively high for most technologies, particularly hydropower. PPA terms also contribute to such inflexible operational characteristics. Table 8 also shows how retrofitting power plants to enhance key operating parameters improves technical flexibility. For example, in a coal-fired power plant, this could be implemented via advanced monitoring and control techniques (the so-called advanced state-space unit control) and other technical interventions (e.g. condensate throttling; partial deactivation of heat pump preheaters and optimization of the feedwater; aid and fuel controls), as were implemented at RWE's Neurath power plant in Germany.

Notably, the existing Thai power system is still sufficiently flexible to effectively respond to ramping requirements for different periods, particularly during the evening peak. However, with the rising share of VRE and distributed energy resources, ramping system requirements are expected to increase due to more significant changes in net demand and increased net demand variability. For example, in the California system, the 3-hour upward ramps in the evening are generally greater than 50% of the daily peak demand, which indicates the need for faster ramping resources.

Table 8 Typical average operating parameters of different technologies.

Technology	Key operating parameters					
	Minimum generation (% of capacity)		Ramp rate (MW/minute)		Warm start time (hours)	
	Typical	Retrofit	Typical	Retrofit	Typical	Retrofit
CCGT	45%	30%	21	56	1.6	0.5
Coal	37%	20%	21	60	6	2.6
OCGT	35%	20%	29	60	0.7	0.3
Hydro	15%	-	60	-	-	-

Sources: IEA (2017d), Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations; NREL (2012), Power Plant Cycling Cost; Gonzalez-Salazar et al. (2018), Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables; Siemens (2017), Flexibility of Coal- and Gas-Fired Power Plants; Agora Energiewende (2017), Flexibility in Thermal Power Plants – With a Focus On Existing Coal-Fired Power Plants.

As claimed by [35], less flexible electrical systems can be more expensive to operate, as they force more expensive units to stay on when less expensive ones could be used to meet the demand. While flexibility has always been a necessary component of electrical systems, given the uncertainty of demand and conventional generation outages, the growth in VRE increases the need for flexible resources. The benefits of zero variable-cost VRE sources include their ability to displace the operating costs and emissions of the conventional electrical system. This primarily means avoiding the costs of operating fossil-fueled generators and associated emissions of criteria pollutants and CO_2. If the electrical system is not sufficiently flexible, the benefits of VRE may be reduced. In higher levels of VRE penetration, the limited flexibility in the system will lead to fossil-generators remaining online. At the same time, cost- and emissions-free wind and solar cannot be accommodated and curtailed. The flexibility of conventional generators plays an essential role in adjusting the increased variability and uncertainty of wind and solar on the electrical system. Increased flexibility can be achieved with changes to operational practices or upgrades to the existing generation. One challenge is understanding the value of increasing flexibility and how this value may change given higher levels of VRE integration.

Research [35] uses a commercial production cost model to measure the impact of generator flexibility on the integration of wind and solar generators. The authors use a system that is based on two balancing areas in the Western United States with a range of wind and solar penetrations between 15% and 60%, where instantaneous penetration of wind and solar is limited to 80%. They evaluate the impact of reducing the minimum generation level of the coal generation fleet from 60% to 40% of nameplate capacity and observe the corresponding decrease in production costs. At low VRE penetration, this increased flexibility provides minimal benefit. However, at higher levels of VRE penetration, increased flexibility results in decreased curtailments, which reduces fuel consumption and decreases the system production cost. They also examine the impact of relaxing the 80% penetration limit, assuming that active power controls and other new technologies allow wind and solar to provide system stability services. These further decrease production costs, particularly in very high penetration scenarios. In all scenarios, emissions of CO_2 decrease as flexibility increases and more VRE is accommodated.

According to [68], the three key features of operational flexibility are:

- **Minimal load:** The lower the minimum load, the larger the range of generation capacity. A low minimum load can also avoid expensive start-ups and shutdowns. However, at minimum load, the power plant operates at lower efficiency, and the lower the load, the more difficult it is to ensure stable combustion without supplemental firing.
- **Start-up time**: The shorter the start-up time, the quicker a power plant reaches its minimum load. Nonetheless, faster start-up times put greater thermal stress on components, reducing their lifetime. The limitation of start-up time is the allowable thermal gradient for components.
- **Ramp rate:** A higher ramp rate allows a power plant operator to adjust net output more rapidly. Nevertheless, rapid change in firing temperature results in thermal stress. The ramp rate limitations are allowable thermal stress and unsymmetrical deformations, storage behavior of the steam generator, quality of fuel used, and the time lag between coal milling and turbine response.

The qualitative representation of key flexibility parameters of a power plant is shown in Figure 33. The illustrative subdivision of a coal power plant is shown in Figure 34, where purple indicates key components to improve flexibility. Numerous technical possibilities to increase the flexibility of coal power plants are shown in Table 9.

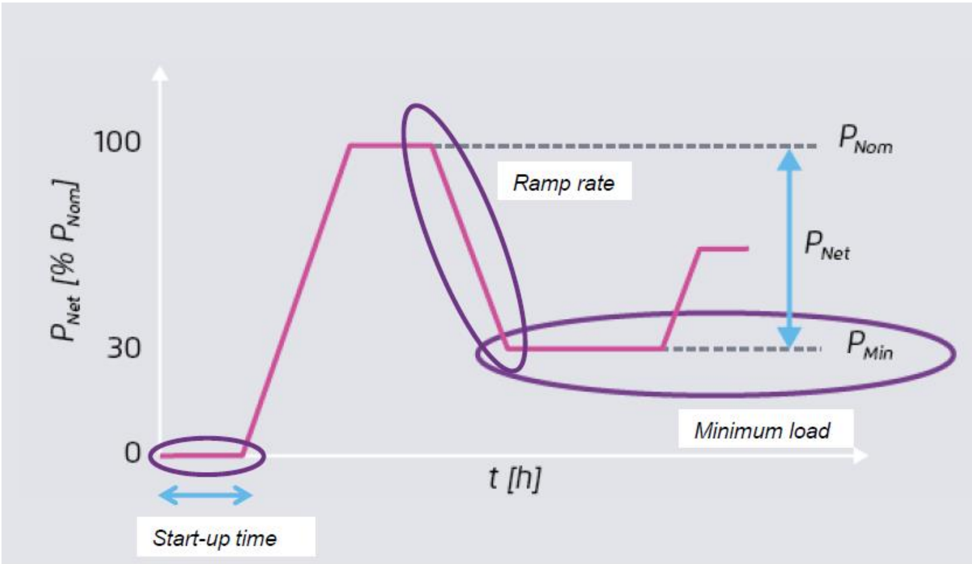


Figure 33 Qualitative representation of key flexibility parameters of a power plant.

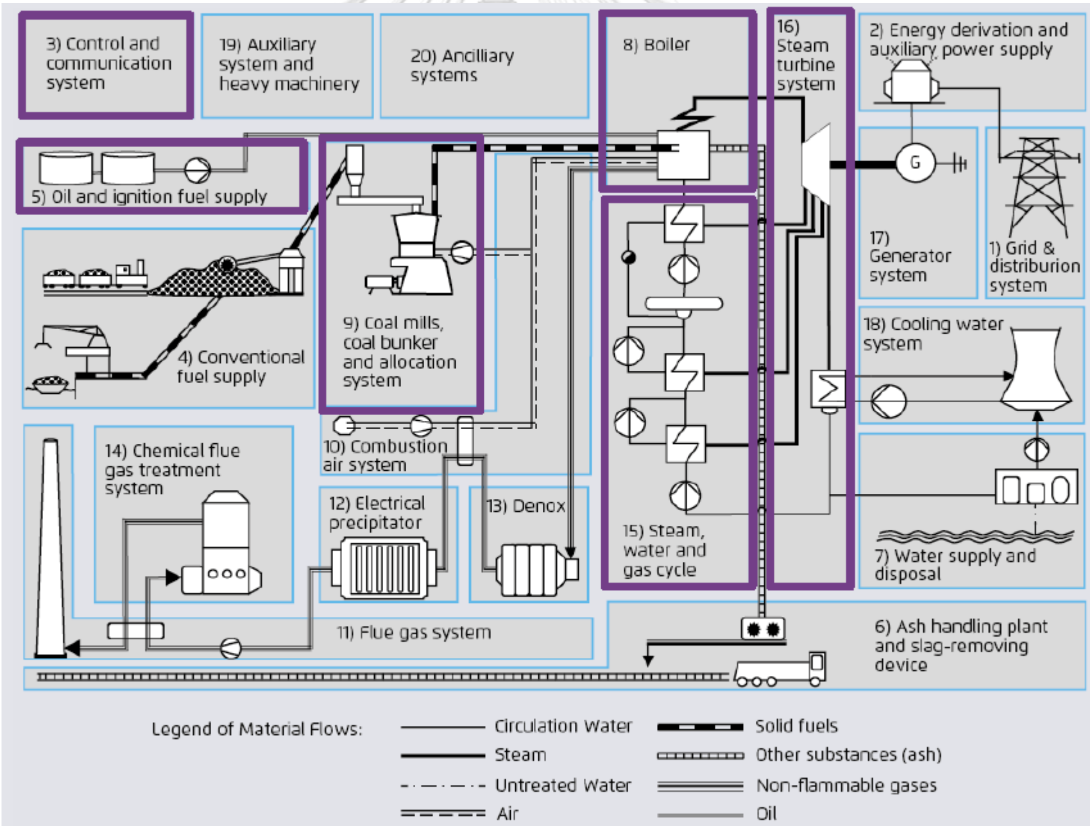


Figure 34 Illustrative subdivision of a coal power plant (purple indicates key components to improve flexibility).

Table 9 Numerous technical possibilities exist to increase the flexibility of coal power plants.

Retrofit measure for reducing:	Minimum load	Start-up time	Ramp rate	Limitations
Indirect Firing	✓		✓	Fire stability
Switching from two mills to single mill operation	✓			Water-steam circuit
Control system and plant engineering upgrade	✓		✓	Fire stability/ thermal stress
Auxiliary firing with dried lignite ignition burner	✓		✓	Fire stability and boiler design
Thermal energy storage for feedwater pre-heating	✓			N/A
Repowering		✓	✓	N/A
Usage of optimized control system		✓		Thermal stress
Thin-walled components /special turbine design		✓		Mechanical and thermal stresses
"New" turbine starts		✓		Turbine design
Reduction of the wall thickness of key components			✓	Mechanical and thermal stresses

Research [68] states that reducing minimum load levels has proven to bring the most benefits. Important enabling factors are the adoption of alternate operation practices, rigorous inspection, and training programs. Several retrofit measures were implemented on German power plants to enhance their flexibility. For example, coal power plant Bexbach (780 MW) reduced of minimum load from 170 MW (22% of P_{Nom}) to 90 MW (11% of P_{Nom}) by switching from two mills to single mill operation. Unit G and H of hard coal power plant Wesweiler upgrades in plant engineering and control reduced the minimum load of 170 MW, as shown in Figure 35, and increased the ramp rate by 10 MW/min. The total retrofit cost amounted to ~60 M€ for each unit. Investment costs for retrofit in flexibility can be roughly estimated in a range from 100 to 500 €/kW. It must be evaluated case by case. Retrofit usually increases the technical lifetime of a power plant by about 10-15 years.

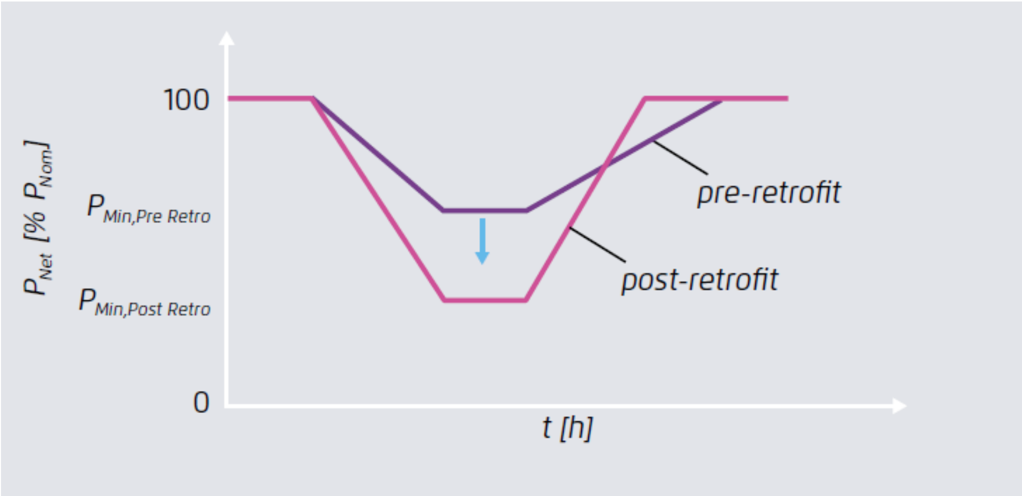


Figure 35 Load curves for pre-retrofit and post-retrofit of Unit G and H at Weisweiler.

Report [69] concludes about flexibility in thermal power plants as follows:

- The existing thermal power plants can provide much more flexibility than often assumed, as experience in Germany and Denmark shows. Coal-fired power plants are often less flexible than gas-fired generation units. But as Germany and Denmark demonstrate, aging hard coal-fired power plants (and even some lignite-fired power plants) already provide large operational flexibility. They adjust their output on a 15-minute basis (intraday market) and even on a 5-minute basis (balancing market) to variations in renewable generation and demand.
- Numerous technical possibilities exist to increase the flexibility of existing coal power plants. Improving the technical flexibility usually does not impair the efficiency of a plant, but it puts more strain on components, reducing their lifetime. Targeted retrofit measures have been implemented in practice on existing power plants, leading to higher ramp rates, lower minimum loads, and shorter start-up times. Operating a plant flexibly increases operation and maintenance costs. However, these increases are small compared to the fuel savings associated with higher shares of renewable generation in the system.
- Flexible coal is not clean, but making existing coal plants more flexible enables the integration of more wind and solar power in the system. However, when gas is competing with coal, carbon pricing remains necessary to achieve a net reduction in CO_2. In some power systems, especially when gas is competing against coal, the flexible operation of coal power plants can lead to increased CO_2 emissions. In those systems, an effective climate policy (e.g. carbon pricing) remains a key precondition for reducing CO_2 emissions.
- It is crucial to adapt to power markets to fully tap the flexibility potential of coal and gas power plants. Proper price signals give incentives for the flexible operation of thermal power plants. Thus, introducing short-term electricity markets and adjusting balancing power arrangements are important measures for remunerating flexibility.

4.2 Bidding strategy

As mentioned in the previous chapters, VRE can change the activities of electricity markets, contributing to MOE. VRE is generally prioritized for supplying electricity in energy markets because of its low marginal costs (MCs). A traditional method to leverage low-cost resources, i.e., VRE, is to maximize its generated electricity (output). The maximization considers SOCs consisting of electrical system constraints and generation characteristic constraints. However, when there is VRE proportion in the markets, the marginal price at that time is inevitably diminished. The greater the VRE output, the greater the drop in marginal prices. Additionally, many countries around the world provide support schemes for RE generation to reach their RE targets. The common support schemes are feed-in tariffs (FIT), contract for difference feed-in tariffs (CFD-FIT), and feed-in premiums (FIP) [51]. The RE support schemes involve prices RE offered to the market [36], which affects MPs and probably makes MOE more severe. As a result, maximizing VRE output into energy markets cannot allow maximum profits from the generators. Selling less energy to the markets to gain high MPs possibly makes more profit than selling maximum energy at low marginal prices.

To mitigate the impacts of VRE on electricity markets, generators might apply bidding strategies to maximize their revenue. In energy markets with theoretically perfect competition, generators offer two parameters to the markets at a specific time: first, their capability to produce energy; second, the price they would like to sell their energy at. Generators will offer the lowest price they can accept without loss to make sure that they can be committed to selling the energy [36]. Those offers determine the merit-order curve over time. The marginal price at that time is then set by the intersection of the merit-order curve and the electricity demand at the time. No market participant can affect the MPs [98]. However, in markets that sometimes experience less than perfect competition, there are potential gains from strategic bidding in the market.

Strategic behavior of generation participants. Generation companies can generally exercise market power through two different strategies [59]. The first one is known as economic withholding and lies in misreporting their operating costs, i.e. reporting in their offers to the market higher than their actual operating costs. The second one is known as physical withholding and lies in misreporting their generation capacity, i.e. offering less than their actual capacity to the market. Both strategies entail a trade-off that the strategic generation company should properly balance. Specifically, economic or physical withholding will tend to increase market prices, but at the same time, it will decrease the (energy) quantity sold by the generation company.

Economic withholding and its implications are demonstrated in Figure 36 [99]. The green line represents the actual supply curve (corresponding to its marginal cost curve) of a strategic generation company i, while the blue curve represents the supply curve reported in its bid (as-bid supply curve). In general, economic withholding can potentially involve increasing the interception of the marginal cost curve with the price axis (y-axis), increasing the slope of the marginal cost curve, or increasing both. In the context of Figure 36, the second alternative (increasing slope) applies, but the following insights are very similar in the case of any of the above alternatives. The interception of the supply curve of generation company i (green or blue line) with the residual demand curve, i.e., the demand curve expressing the demand side and the operation of the other generation companies in the market (red curve) determines the market-clearing outcome. Figure 36 demonstrates that economic withholding (reporting the blue line instead of the green line) increases the market-clearing price, which has a positive effect on the generation company's i profit, while it decreases the quantity sold by the generation company i, which has a negative effect on its profit. This trade-off should be properly balanced by the generation company [63].

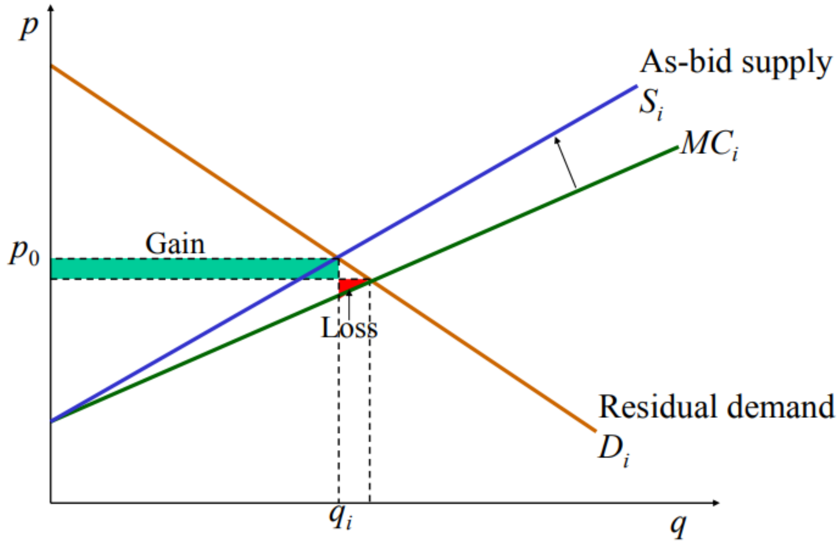


Figure 36 Illustration of market power exercise by generation participant through economic withholding.

Physical withholding and its implications are demonstrated in Figure 37 [70]. The right supply curve line represents the actual supply curve (corresponding to a truthful report of its generation capacity) of a strategic generation company i, while the left supply curve represents the supply curve reported in its bid; this is moved to the left as the company offers less than its actual capacity to the market. Figure 37 demonstrates that physical withholding (reporting the left line instead of the right line) again increases the market-clearing price, which has a positive effect on the generation company's i profit. At the same time, it decreases the quantity sold by generation company i, which has a negative effect on its profit. This trade-off should be properly balanced by the generation company [64].

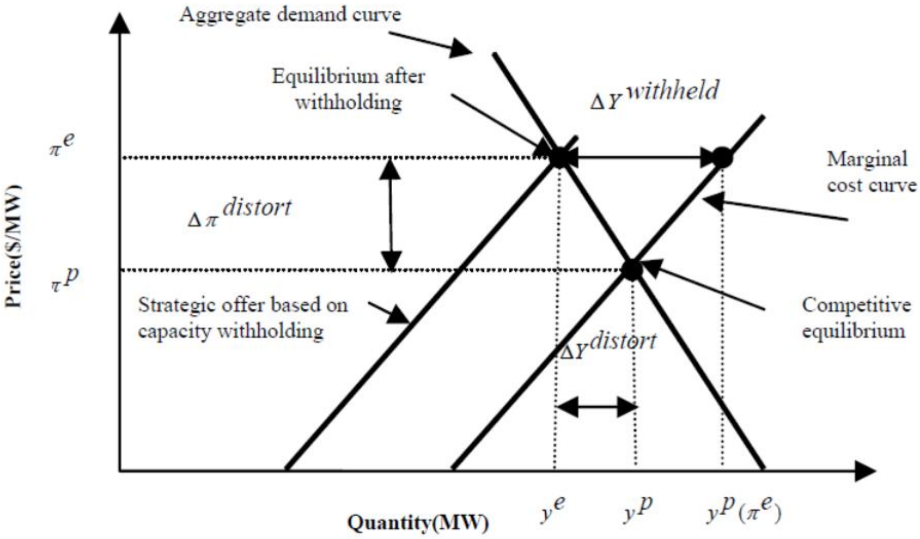


Figure 37 Illustration of market power exercise by generation participant through physical withholding.

Physical withholding is directly relevant to the generation schedule of generators. For VRE, it is relevant to curtailment. VRE curtailment is a reduction in the output of wind or solar generation from the output possible with the available wind or sunlight [36, 39, 71-73]. Regarding bidding strategy, VRE generators might curtail their output following their strategic bidding to maximize profits from the markets [36-38]. In markets, a small amount of capacity at the steepest part of the merit-order curve makes a significant difference in marginal prices. Research [20] has stated that, in the United States, the average reductions in MPs for an additional percentage of VRE penetration are 0.19–0.81 $/MWh before curtailment and 0.21–0.87 $/MWh after curtailment.

There is no standard method to measure curtailment. However, the common metric to measure it is a percent of the output the generation could have produced [39]. Many studies stated that VRE curtailment levels grow with VRE penetration [100]. There are both technical and economic reasons to curtail VRE. The most common technical reasons are to avoid insufficient transmission, local congestion, and excessive supply during low-load periods (oversupply). These different reasons may correlate in time. The curtailment called technical curtailment is done by system operators; the curtailed generators could gain compensation or remuneration for their curtailed energy based on the regulations of each system. For economic reasons, VRE curtailment contributes to significant savings in both grid and storage extension investments. Avoiding the curtailment would require investing in transmission lines and storage, which would be very costly if it were only used for a few hours per year. The curtailment called economic curtailment is done by both system operators to minimize system costs and generators to maximize their profits [36, 39, 72, 73, 100].

On the other hand, curtailment can be problematic since it decreases the capacity factor of the generators. When the design's electricity generation is lower than intended, it can be considered as a reduction in generators' revenue from selling less electricity than their capability [12, 14, 17-19]. Curtailment also decreases generators' ability to recover their capital costs because of the reductions in revenue [39]. Compensation to generators for revenue loss from curtailment varies greatly across the U.S. and Europe [73]. For technical curtailment, the costs in terms of lost generation are discussed based on MPs and support levels, including the rationale for compensating the curtailed energy. For economic curtailment, it is allowed without compensation [36].

According to [37], A firm frequently exercises its market power by withholding a part of its capacity that could be produced at the market price – physical withholding; or by asking for a higher price than marginal cost – economic withholding. These two approaches lead to the same result: higher market prices, higher profits, and withheld output. If there is a perfectly competitive market, prices will equal the marginal cost of the most expensive plant producing electricity.

Chapter 5

The proposed method for determining the impacts of VRE integration and assessing the mitigation of the impacts

This dissertation proposes a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue and assess the mitigation of the impacts. The algorithm is a combination of methods and consists of two main parts. First, determining the impacts of VRE integration on total system costs and electricity generation revenue (Section 5.1). Second, the VRE impacts mitigation by enhancing system flexibility and using a bidding strategy (Section 5.2). In this dissertation, VRE resources consist of solar and wind. Conventional generators maintained the VRE generators' technical impacts on the electrical system, i.e., hydro generators, which have considerable mechanical inertia, and thermal generators consisting of the natural gas combined cycle (CCGTs) and coal combustion generators. Figure 38 shows an algorithm to determine the impacts of VRE integration and assess the mitigation of the impact presented in this chapter.

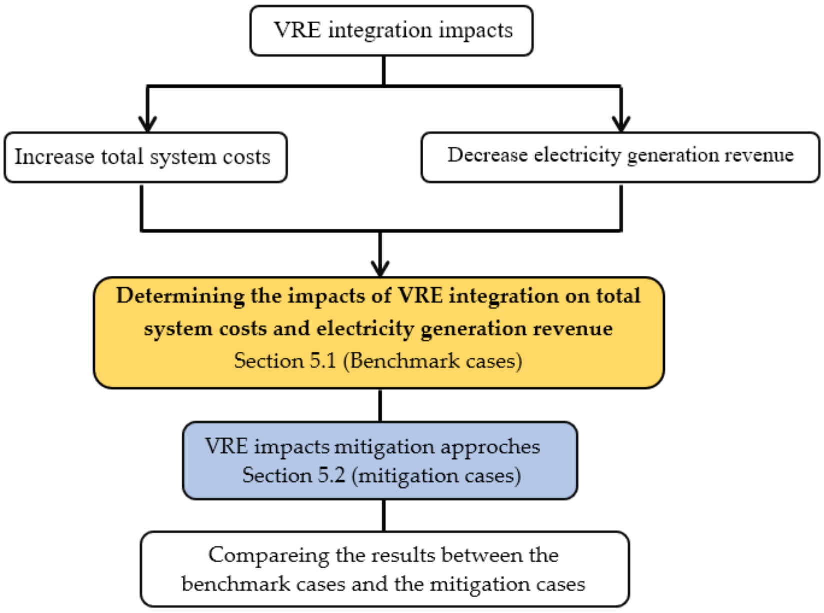


Figure 38 Algorithm to determine the impacts of VRE integration and assess the mitigation of the impact.

5.1 Determining the impacts of VRE integration on total system costs and electricity generation revenue

The method to determine the impacts of VRE integration on total system costs and electricity generation revenue consists of two subsections. The first subsection minimizes total system costs, and direct integration costs at a specified VRE penetration level, considering SPCs and SOCs using the power balance- and the unit commitment-based model (Section 5.1.1). The minimized total system costs at the specified penetration level were derived together with the optimal generation mix and the optimal generation schedule. After that, direct integration costs can be pointed out. The second subsection is calculating electricity generation revenue. Indirect integration costs were calculated by analyzing the optimal generation mix and the optimal generation schedules. The energy market simulation was used to calculate indirect integration costs and evaluate generation revenue from the energy market. The capacity market simulation was used to calculate the electricity generation revenue from the capacity market (Section 5.1.2). The semi-dynamic approach was used to capture the electricity supply and demand dynamics. The approach selected typical days to represent the power variations along the year instead of using all days in a year. As mentioned by [42], the idea behind this approach is a compromise between having some dynamics and, at the same time requiring fewer data and lower processing intensity for the mid/long-term planning tools. The representative days were selected to capture critical 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 60% of electricity demand to determine the relations between VRE penetration, total system costs, and electricity generation revenue. VRE resources consisted of solar and wind. Conventional generators maintained the VRE generators' technical impacts on the electrical system, i.e., hydro generators, which have considerable mechanical inertia, and thermal generators consisting of CCGT and coal combustion generators [4, 101].

5.1.1 Minimization of total system costs

The minimization of total system costs incurred from generating electricity was performed to deliver the least cost to customers considering SPCs and SOCs. The method is two-stage optimization; the first stage is electrical system planning. This stage determines the yearly generation mix of the system throughout the planning horizon, considering the projected costs, electricity demand, and SPCs. The state also roughly determines the hourly power of each type of generator. The second stage is electrical system operation. In this stage, generation mix, flexibility constraints, and results from the first stage can be further scrutinized using more detailed constraints with different degrees of complexity, i.e., SOCs. Such validation tools scrutinize operational aspects of a power system and give high-level indications about whether the generation mix resulting from the first stage would offer sufficient flexibility. According to the semi-dynamic approach, the representative days in a considered year were a peak day, a workday in summer, a holiday in summer, a workday in rainy season, a holiday in rainy season, a workday in winter, and a holiday in winter. The details of the two-stage optimization are as follow:

5.1.1.1 The first stage: generation expansion planning

The objective function of generation expansion planning was to minimize total system costs at a specified VRE penetration level throughout the planning horizon (Y). Total system costs consist of levelized capital costs ($CC_y^{Planning}$), and variable costs ($VC_y^{Planning}$). The calculation also considers the discount rate (r). The objective function is shown in equation (1).

$$\text{Min}\left\{\sum_{y}^{Y}\left(\frac{VC_y^{Planning}}{(1+r)^y}+\frac{CC_y^{Planning}}{(1+r)^y}\right)\right\} \tag{1}$$

$VC_y^{Planning}$ (\$/year) is the variable costs (VCs) of the system in the considered year (*y*). The VCs of the systems consist of VCs of all generators throughout *y*. VCs of each type of generator at time *t* was calculated from the generator's projected variable cost (VC_{nType}), which are constants multiplied by its energy output at time *t* ($E_{nType,d}(t)$), which depends on the considered day (*d*). The summation of the VCs throughout the daily operation horizon (*T*) was the VCs of a considered *d*; then, the VCs were multiplied by the number of the day *d* in a year (N_d). The summation of VCs of all generators throughout *T* in all representative days (*RD*) is the VC of the system in the considered year *y* as shown in equation (2).

$$VC_y^{Planning}=\sum_{d\in RD}\left(\left(\sum_{t=1}^{T}\sum_{nType}^{N_{Type}}VC_{nType}\times E_{nType,d}(t)\right)\times N_d\right) \tag{2}$$

For capital costs (CCs), the costs depend on the installed capacity of generators, as shown in (3). $CC_y^{Planning}$ (\$/year) is the summation of CCs of VRE, hydro, and thermal generators in *y*. *C* is the capital cost of the generator (\$/year/MW). *ICAP* is the installed capacity (MW) needed to provide the electrical system's firm capacity (MW). 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 (3) only account for the electricity generation component, i.e., generators, not for the total costs of the reservoirs.

$$\begin{aligned}CC_y^{Planning}&=(C^{CCGT}\times ICAP_y^{CCGT})+(C^{Coal}\times ICAP_y^{Coal})\\&+(C^{Hydro}\times ICAP_y^{Hydro})\\&+(C^{Solar}\times ICAP_y^{Solar})+(C^{Wind}\times ICAP_y^{Wind})\end{aligned} \tag{3}$$

The objective function is optimized considering SPCs consisting of the limitation of capacity expansion, the reserve margin, capability of VRE generation from the given sunlight or wind, serving electricity demand, and hydro energy limitation. For the constraints relevant to the limitation of capacity expansion and the installed capacity of VRE, $ICAP_1^{Solar}$ and $ICAP_1^{Wind}$ at the start of the planning horizon must equal to the existing penetration as shown in equations (4) and (5). The total *ICAP* of solar and wind generators at the end of the planning horizon needs to be equal to or less than the considered VRE penetration level (L_{VRE}) as shown in (6). The annual increase in VRE installation must be less or equal to the annual integration limitations which are constants, as shown in equations (7) and (8). The installation of VRE must be increased throughout the planning horizon, as shown in equations (9) and (10). The maximum installation of hydro and coal generation must be less than or equal to the limitation depending on each country's electrical planning context, as shown in equations (11) and (12).

$$ICAP_1^{Solar} = Existing\ solar\ penetration \tag{4}$$

$$ICAP_1^{Wind} = Existing\ wind\ penetration \tag{5}$$

$$ICAP_Y^{Solar} + ICAP_Y^{Wind} = L^{VRE} \times D_{Y,peak}(t_{peak}) \tag{6}$$

$$ICAP_y^{Solar} - ICAP_{y-1}^{Solar} = Solar\ Integration\ limit \tag{7}$$

$$ICAP_y^{Wind} - ICAP_{y-1}^{Wind} = Wind\ Integration\ limit \tag{8}$$

$$ICAP_y^{Solar} \geq ICAP_{y-1}^{Solar} \tag{9}$$

$$ICAP_y^{Wind} \geq ICAP_{y-1}^{Wind} \tag{10}$$

$$ICAP_y^{Hydro} \leq limit\ ICAP_y^{Hydro} \tag{11}$$

$$ICAP_y^{Coal} \leq limit\ ICAP_y^{Coal} \tag{12}$$

The electricity demand serving constraint is that the total power output from each type of generation on the considered day *d* at time *t* ($P_{d,y}(t)$) must be equal to the electricity demand on the considered day at time *t* ($D_{d,y}(t)$), as shown in (13).

$$\begin{aligned} D_{d,y}(t) = {} & P_{d,y}^{CCGT}(t) + P_{d,y}^{Coal}(t) + P_{d,y}^{Hydro}(t) \\ & + P_{d,y}^{Solar}(t) + P_{d,y}^{Wind}(t) \qquad ; \forall t \in T, d \in RD, y \in Y \end{aligned} \tag{13}$$

The electrical system constraints include procuring adequate planning reserve margin (PRM), serving electricity demand, 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 ($D_{y,peak}$), as shown in (14). The total *FCAP* can be calculated as shown in (15). The *FCAP* of VRE generators depends on their capacity credit (*Cr*), as shown in (16). The *FCAP* of thermal generators is their unforced capacity calculated from their forced outage rate (FOR)[4, 102]. This method used the average FOR of all generator units to calculate the generators' unforced capacity, as shown in (17). If the average FOR is high, the unforced capacity ($1-\overline{FOR}$) would be low, contributing to the 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 *ICAP* of CCGT, coal, and hydro generators were the maximum of the total power output from all generators at time *t* throughout *T* among all *RD*, as shown in (18)-(20).

$$Total\ FCAP_y \geq (1 + PRM_{req}/100) \times D_{y,peak}(t_{peak}) \quad ; \forall y \in Y \tag{14}$$

$$\begin{aligned} Total\ FCAP_y = {} & FCAP_y^{VRE} + FCAP_y^{Thermal} \\ & + FCAP_y^{Hydro} + FCAP_y^{Bilateral} \quad ; \forall y \in Y \end{aligned} \tag{15}$$

$$FCAP_y^{VRE} = (Cr^{Solar} \times ICAP_y^{Solar}) + (Cr^{Wind} \times ICAP_y^{Wind}) \quad ; \forall y \in Y \tag{16}$$

$$\begin{aligned} FCAP_y^{Thermal} = {} & ((1 - \overline{FOR}^{CCGT}) \times ICAP_y^{CCGT}) \\ & + ((1 - \overline{FOR}^{Coal}) \times ICAP_y^{Coal}) \quad ; \forall y \in Y \end{aligned} \tag{17}$$

$$ICAP_y^{CCGT} \geq P_{d,y}^{CCGT}(t) \;\; ; \forall t \in T, d \in RD, y \in Y \tag{18}$$

$$ICAP_y^{Coal} \geq P_{d,y}^{Coal}(t) \;\; ; \forall t \in T, d \in RD, y \in Y \tag{19}$$

$$ICAP_y^{Hydro} \geq P_{d,y}^{Hydro}(t) \;\; ; \forall t \in T, d \in RD, y \in Y \tag{20}$$

$P^{Solar}(t)$ and $P^{Wind}(t)$ 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). *DD* is the set of representative days in a season, i.e., peak day (only occur in summer), a workday, and a holiday. *S* is the set of the season, i.e., summer, rainy season, winter.

$$P_{y,s,d}^{Solar}(t) \leq Pr_s^{Solar}(t) \times ICAP_y^{Solar} \quad ; \forall t \in T,\ d \in DD,\ s \in S, y \in Y \tag{21}$$

$$P_{y,s,d}^{Wimd}(t) \leq Pr_s^{Wind}(t) \times ICAP_y^{Wind} \quad ; \forall t \in T,\ d \in DD,\ s \in S, y \in Y \tag{22}$$

Equation (23) shows the constraint for the limitations of hydro generators, which depend on the plant factor of hydro generation ($PF_{y,s}$), which is a constant calculated from the amount of water reserved in the considered season of the considered year *y*.

$$\sum_{d \in RD} \left(\sum_{t}^{T} P_{d,s,y}^{Hydro}(t) \times N_{s,d} \right) \leq ICAP_y^{Hydro} \times PF_{y,s} \;\; ; \forall s \in S, y \in Y \tag{23}$$

The objective function, which is a linear function, was solved by the LP optimization tool “linprog” in MATLAB.

5.1.1.2 The second stage: system operation

The second stage is electrical system operation. Operation costs must be minimized to deliver the least cost to customers. Operation costs consist of daily variable costs ($VC_d^{Operation}$), and direct integration costs. This dissertation focused on profile costs for direct integration costs because they comprise the highest proportion of integration costs. Thus, only flexibility costs ($FC_d^{Operation}$) were included. The optimization did not include utilization costs (UC), which are indirect integration costs. If the costs were included, all of the generators' revenue reductions would burden the system. The objective function was to minimize operation costs in a day at a specified VRE penetration level, as shown in equation (24).

$$\text{Min}\left\{VC_d^{Operation} + FC_d^{Operation}\right\} \tag{24}$$

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 $VC_d^{Operation}$ of each generator unit (n) within a considered period (t) were different depending on its committed power at the time. All generators' units (N_{Sys}) have VCs. $VC_d^{Operation}$ (\$/day) was determined by unit-commitment results of the representative day as shown in equations (25).

$$VC_d^{Operation} = \sum_{t=1}^{T}\left(VC_d^{Solar}(t) + VC_d^{Wind}(t) + \sum_{n}^{N_{Thermal}} VC_{n,d}^{Thermal}(t) + \sum_{n}^{N_{Hydro}} VC_{n,d}^{Hydro}(t) \right) \quad ;\ \forall\ d \in RD \tag{25}$$

VCs of n at time t ($VC_n(t)$) were calculated from the generators' marginal costs (MCs) multiplied by their energy output ($E_n(t)$). Equations (26) to (28) show the $VC_n(t)$ calculation of VRE and hydro generators, where their MCs are constant values. Equation (29) shows the calculation of the $VC_n(t)$ of thermal generators, the MCs of which are constant values that depend on their incremental cost curves, which indicate the cost of producing one more MW of power from the thermal generators. This dissertation treats the curves as piecewise linear functions. $MC_{n,1}^{Thermal}, MC_{n,2}^{Thermal}, MC_{n,3}^{Thermal}$ are the piecewise costs from the incremental cost curve of n. $P_{n,Thermal}(t)$ is the power output of n at time t; $Pmin_n^{Thermal}$ is the minimum power output of n, and $P_{n,R1}^{Thermal}, P_{n,R2}^{Thermal}, P_{n,R3}^{Thermal}$ are ranges of piecewise power derived from the incremental cost curve of n. Note that MCs, $Pmin_n^{Thermal}$, and $P_{n,R}^{Thermal}$ are constants.

$$VC_n^{Hydro}(t) = MC^{Hydro} \times E_n^{Hydro}(t)\ ;\ \forall t \in T \tag{26}$$

$$VC_n^{Solar}(t) = MC^{Solar} \times E_n^{Solar}(t)\ ;\ \forall t \in T \tag{27}$$

$$VC_n^{Wind}(t) = MC^{Wind} \times E_n^{Wind}(t)\ ;\ \forall t \in T \tag{28}$$

$$VC_n^{Thermal}(t) = \begin{cases} MC_{n,1}^{Thermal} \times E_n^{Thermal}(t) & ;\quad Pmin_n^{Thermal} \le P_n^{Thermal}(t) \le P_{n,R1}^{Thermal} \\ MC_{n,2}^{Thermal} \times E_n^{Thermal}(t) & ;\quad P_{n,R1}^{Thermal} < P_n^{Thermal}(t) \le P_{n,R2}^{Thermal} \\ MC_{n,3}^{Thermal} \times E_n^{Thermal}(t) & ;\quad P_{n,R2}^{Thermal} < P_n^{Thermal}(t) \le P_{n,R3}^{Thermal} \end{cases} \tag{29}$$

For flexibility costs (FCs), $FC^{Operation}_{Daily}$ of each generator unit (*n*) within a considered period (*t*) differed depending on its committed start status at the time. Only thermal units ($N_{Thermal}$), i.e., CCGTs and coal, have FCs. This is because FCs occur from turning boilers, steam lines, turbines, and auxiliary components on and off, actions that undergo unavoidably large thermal and pressure stress. Thus FCs only occur in thermal generators [103]. FCs of *n* at time *t* are the startup costs of unit *n* at time *t* calculated by the multiplication of the unit *n* start status at time *t* ($S_n(t)$) and its startup costs (SC_n) which is a constant. $FC^{Operation}_{Daily}$ (\$/day) were determined by summation FCs of *n* throughout *T* in the representative day as shown in equations (30).

$$FC^{Operation}_{Daily} = \sum_{t=1}^{T} \sum_{n}^{N_{Thermal}} SC_n \times S_{n,d}(t) \quad ; \forall d \in RD \tag{30}$$

The objective function was optimized, subject to SOCs. This dissertation divided the constraints into two groups: first, electrical system constraints, such as serving electricity demand, committing must-run units, and providing the operating reserves requirement that covers demand and VRE forecast errors, along with the spinning reserves requirement for contingency events fixed by the N-1 approach;

Equation (31) shows the serving electricity demand constraint where the total power output from all generators at time *t* must be equal to the electricity demand at time *t* ($D_d(t)$)

$$\begin{aligned} D_d(t) = & \sum_{n,CCGT}^{N_{CCGT}} (P^{CCGT}_{n,d}(t)) + \sum_{n,Coal}^{N_{Coal}} (P^{Coal}_{n,d}(t)) \\ & + \sum_{n,Hydro}^{N_{Hydro}} (P^{Hydro}_{n,d}(t)) + P_d^{Solar}(t) + P_d^{Wind}(t) \ ; \forall t \in T, d \in RD \end{aligned} \tag{31}$$

Equation (32) shows the committing must-run units constraint where the summation of the online status of the must-run unit ($ON^{Must-run}_{n}(t)$) has to be equal to *T*, which means the unit is operated all the time within the considered day

$$T = \sum_{t=1}^{T} ON^{Must-run}_{n,d}(t) \quad ; \forall n \in N_{Must-run}, t \in T \ , \ d \in RD \tag{32}$$

Equation (33) to (36) shows the providing operating reserve requirement constraint. The operating reserves provided by thermal generators at time *t* ($OR^{Thermal}_{n,d}(t)$) need to cover balancing requirements for the demand forecast errors (BR^{D}_{d}) and VRE forecast error (BR^{VRE}_{d}), along with the spinning reserves requirement for contingency events fixed by the N-1 approach ($SR_{N\text{-}1}$). Note that $Pmax^{Thermal}_{n}$, $Error$, and $R^{Up}_{n,15\min}$ are constants.

$$OR_{n,d}(t) = SR_{N\text{-}1} + BR^{D}_{d} + BR^{VRE}_{d}(t) \quad ; \forall n \in N_{Thermal}, t \in T \tag{33}$$

$$OR_{n,d}(t) = \begin{cases} Pmax_n - P_{n,d}(t) & ; \ Pmax_n - P_{n,d}(t) \le R^{Up}_{n,15\min} \ ; \forall n \in N_{Thermal}, t \in T \\ R^{Up}_{15\min} \times ON_{n,d}(t) & ; \ Pmax_n - P_{n,d}(t) \ge R^{Up}_{n,15\min} \ ; \forall n \in N_{Thermal}, t \in T \end{cases} \quad (34)$$

$$BR^D = D_d(t) \times Error^D \ ; \forall t \in T \quad (35)$$

$$BR^{VRE} = (ICAP^{Solar} \times Error^{Solar}(t)) + (ICAP^{Wind} \times Error^{Wind}(t)) \ ; \forall t \in T \quad (36)$$

The operating reserve constraints were linearized by using the big-M method, as shown in equations (37) to (40). Equations (37) and (38) are the formula for determining if remain power of the generator is less than or more than its 15 min ramping capability. Equations (39) to (42) are the formula for indicating the provided operating reserve of the generator using *u* as the indicator.

$$M(u_{n,d}(t)) \ge (Pmax_n ON_{n,d}(t) - P_{n,d}(t)) - R^{Up}_{n,15\min} \ ; \forall n \in N_{Thermal}, t \in T \quad (37)$$

$$M(1 - u_{n,d}(t)) \ge R^{Up}_{n,15\min} - (Pmax_n ON_{n,d}(t) - P_{n,d}(t)) \ ; \forall n \in N_{Thermal}, t \in T \quad (38)$$

$$OR_{n,d}(t) \le (Pmax_n ON_{n,d}(t)) - P_{n,d}(t) \ ; \forall n \in N_{Thermal}, t \in T \quad (39)$$

$$OR_{n,d}(t) \le R^{Up}_{n,15\min} ON_{n,d}(t) \ ; \forall n \in N_{Thermal}, t \in T \quad (40)$$

$$OR_{n,d}(t) \ge R^{Up}_{n,15\min} u_{n,d}(t) - R^{Up}_{n,15\min}(1 - ON_{n,d}(t)) \ ; \forall n \in N_{Thermal}, t \in T \quad (41)$$

$$OR_{n,d}(t) \ge Pmax_n(ON_{n,d}(t) - u_{n,d}(t)) - P_{n,d}(t) - Pmax_n u_{n,d}(t) \ ; \forall n \in N_{Thermal}, t \in T \quad (42)$$

Second, the generation characteristic constraints consist of the relationship between the operating status of a generator, minimum/maximum generation, ramping capability, and the limitations of hydro generators, which depend on the amount of water reserved in the considered day. Equation (43) shows the relationship between the online status of *n* ($ON_{n,d}(t)$) and the start status of *n* ($S_{n,d}(t)$).

$$ON_{n,d}(t) - ON_{n,d}(t-1) \le S_{n,d}(t) \ ; \forall n \in N_{Dispatch}, t \in T \quad (43)$$

Equations (44) and (45) show the minimum and maximum generation constraints. The constraints are involved by the relation of the power output of *n* at time *t* ($P_n(t)$) and $ON_n(t)$.

$$P_{n,d}(t) \ge Pmin_{n,d} \times ON_{n,d}(t) \ ; \forall n \in N_{Dispatch}, t \in T \quad (44)$$

$$P_{n,d}(t) \ge Pmax_{n,d} \times ON_{n,d}(t) \ ; \forall n \in N_{Dispatch}, t \in T \quad (45)$$

Equation (46) and (47) 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 ($R_{n,1hr}^{Up}$). The decreased power output of n must be less than its ramp-down capability in 1 hour ($R_{n,1hr}^{Down}$). Note that $R_{n,1hr}^{Up}$ and $R_{n,1hr}^{Down}$ are constants

$$P_{n,d}(t) - P_{n,d}(t-1) \le R_{n,1hr}^{Up} \quad ; \forall n \in N_{Dispatch}, t \in T \tag{46}$$

$$P_{n,d}(t-1) - P_{n,d}(t) \le R_{n,1hr}^{Down} \quad ; \forall n \in N_{Dispatch}, t \in T \tag{47}$$

Equation (48) and (49) shows minimum up and downtime constraints, respectively. Where M is a huge number. The constraints will be activated only when *n* changes its online status, from online to shutdown or from shutdown to online. Note that $Min.time_n^{Up}$ and $Min.time_n^{Down}$ are constants.

$$\sum_{t-Min.time_n^{Up}}^{t-1} ON_{n,d}(t) \ge Min.time_n^{Up}(ON_{n,d}(t-1) - ON_{n,d}(t)) \;\; ; \forall n \in N_{Dispatch}, t \in T \tag{48}$$

$$\sum_{t-Min.time_n^{Down}}^{t-1} ON_{n,d}(t) \le [1 + (ON_{n,d}(t-1) - ON_{n,d}(t))]\mathrm{M} \;\; ; \forall n \in N_{Dispatch}, t \in T \tag{49}$$

Equation (50) shows the constraint for the limitations of hydro generators, which depend on the plant factor of n ($Plant\ factor_n$), which is a constant calculated from the amount of water reserved in the considered year.

$$\sum_{t}^{T} P_{n,d}^{Hydro}(t) \le Pmax_n^{Hydro} \times PF_{n,s} \quad ; \forall n \in N_{Hydro} \tag{50}$$

$P_d^{Solar}(t)$ and $P_d^{Wind}(t)$ 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 (51) and (52).

$$P_d^{Solar}(t) \le Pr_S^{Solar}(t) \times ICAP^{Solar} \quad ; \forall t \in T \tag{51}$$

$$P_d^{Wind}(t) \le Pr_S^{Wind}(t) \times ICAP^{Wind} \quad ; \forall t \in T \tag{52}$$

The UCP was defined as MIP because it can address issues with non-convexity related to the SOCs [40]. The UCP, which is a mixed-integer linear function, was solved by the MILP optimization tool "Intlinprog" in MATLAB.

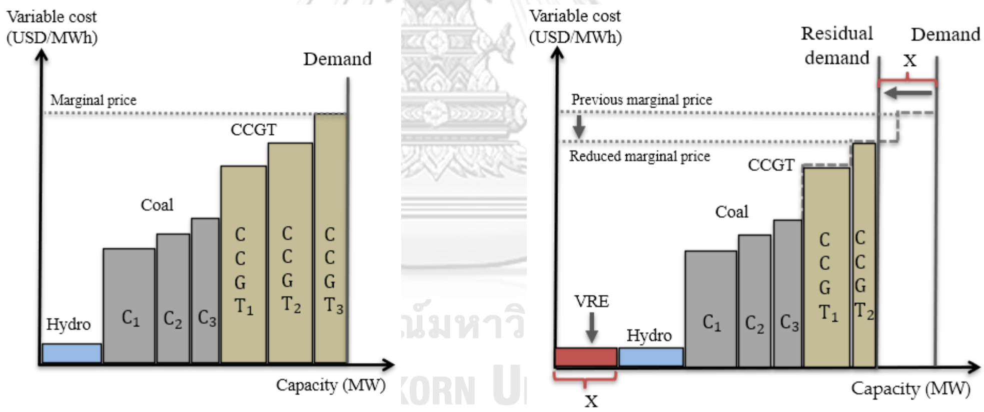
The total system costs at a specific VRE penetration level throughout the planning horizon were calculated by the $CC_y^{Planning}$ from the 1st stage and the $VC_{Daily}^{Operation}$ and $FC_{Daily}^{Operation}$ from the 2nd stage, as shown in equation (53)

$$Total\ system\ costs = \sum_{y}^{Y}\left(\frac{CC_y^{Planning}}{(1+r)^y} + \frac{\sum_{d\in RD}\left((VC_d^{Operation} + FC_d^{Operation}) \times N_{d,s}\right)}{(1+r)^y}\right) \tag{53}$$

5.1.2 Calculating electricity generation revenue

In electrical systems with a liberalized structure, the reduced supply of energy and MPs causes indirect integration costs that indicate the generators' profitability. In this section, the generation mix and generation schedule resulting from the optimization in Section 5.1.1 were further analyzed in Section 5.1.2.1. The energy market simulation was done in Section 5.1.2.2. Both sections present the determination of electricity generation revenue from the energy market and the indirect integration costs, i.e., the cost incurred by utilization effects (utilization costs). Section 5.1.2.3 presents the capacity market simulation to determine the electricity generation revenue from the capacity market.

To clarify, this paper divides the integration 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. Figure 39 shows the occurrence of utilization effects via the merit-order curve at a considered time.



(a) (b)

Figure 39 Occurrence of utilization effects: (a) Merit-order curve without VRE at a considered time; (b) Merit-order curve with VRE at a considered time.

As shown in Figure 39 (b), $CCGT_3$ is taken out of the market. $CCGT_2$ must reduce its generation level to prioritize the cheap energy from VRE. Hydro, $CCGT_1$, and C_1-C_3 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, UC_E only occurs to $CCGT_2$, $CCGT_3$, and VRE (if it is curtailed). However, each MWh from any generator receives less revenue because the MPs are reduced. Therefore, UC_{MP} occurs to every generator.

5.1.2.1 Calculation of utilization costs from the reduction in supplied energy

UC_E can occur to both VRE and conventional generators. For the VRE generators, UC_E are caused by the curtailment of VRE generation. The costs are the difference between the Capital costs/energy of generators with and without curtailment. The calculations of UC_E incurred on VRE generators are shown in equations (54) and (55), where $E^{Utilized}$ is the energy output of VRE generators after curtailment derived from the optimal generation schedule.

$$UC_E^{Solar} = \frac{C^{Solar} \times ICAP^{Solar}}{E_{Solar}^{Utilized}} - \frac{C^{Solar} \times ICAP^{Solar}}{ICAP^{Solar} \times \sum_{t=1}^{T} Pr^{Solar}(t)} \tag{54}$$

$$UC_E^{Wind} = \frac{C^{Wind} \times ICAP^{Wind}}{E_{Wind}^{Utilized}} - \frac{C^{Wind} \times ICAP^{Wind}}{ICAP^{Wind} \times \sum_{t=1}^{T} Pr^{Wind}(t)} \tag{55}$$

For conventional generators, UC_E are caused by the reduction in the generators' utilization. The costs are the difference between the Capital costs/energy of the generators with and without VRE integration. The calculations of UC_E incurred on conventional and hydro generators are shown in equations (56)–(58). $ICAP^{withVRE}$, $ICAP^{withoutVRE}$, $E^{withVRE}$, and $E^{withoutVRE}$ 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.

$$UC_E^{Coal} = \frac{C^{Coal} \times ICAP_{withVRE}^{Coal}}{E_{withVRE}^{Coal}} - \frac{C^{Coal} \times ICAP_{withoutVRE}^{Coal}}{E_{withoutVRE}^{Coal}} \tag{56}$$

$$UC_E^{CCGT} = \frac{C^{CCGT} \times ICAP_{withVRE}^{CCGT}}{E_{withVRE}^{CCGT}} - \frac{C^{CCGT} \times ICAP_{withoutVRE}^{CCGT}}{E_{withoutVRE}^{CCGT}} \tag{57}$$

$$UC_E^{Hydro} = \frac{C^{Hydro} \times ICAP_{withVRE}^{Hydro}}{E_{withVRE}^{Hydro}} - \frac{C^{Hydro} \times ICAP_{withoutVRE}^{Hydro}}{E_{withoutVRE}^{Hydro}} \tag{58}$$

5.1.2.2 Calculation of utilization costs from the reduction in MPs

UC_{MP} are the difference between the MPs with and without VRE integration at a specific time ($\Delta\lambda(t)$) multiplied by the energy supplied by all generators at a specific time ($E_{total}(t)$), as shown in equations (59) – (61). The MP of each considered period at a VRE penetration level ($\lambda(t)$) was derived by the merit-order simulation. The $\lambda(t)$ is the function of the merit-order curve and electricity demand (D(t)) at a specific time, as shown in equation (62). This dissertation assumes that the wholesale electricity 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 [36]. Thus, the merit-order curve is set from the MC of each generator.

$$UC_{MP}(t) = \Delta\lambda(t) \times E_{Total}(t) \;\; ; \forall t \in T \tag{59}$$

$$\Delta\lambda(t) = (\lambda_{without\,RE}(t) - \lambda_{with\,RE}(t)) \;\; ; \forall t \in T \tag{60}$$

$$E_{Total}(t) = E_{CCGT}^{withVRE}(t) + E_{Coal}^{withVRE}(t) + E_{Hydro}^{withVRE}(t) + E_{Solar}^{Utilized}(t) + E_{Wind}^{Utilized}(t) \;\; ; \forall t \in T \tag{61}$$

$$\lambda(t) = Merit\text{-}order\,curve(D_d(t)) \;\; ; \forall t \in T \tag{62}$$

The inputs of the method are electricity demand profiles of the representative day, VRE generation profiles, VRE capacity credit, forecast error statistics of electricity demand and VRE, and capital and operating costs of conventional and VRE. Lastly, a sensitivity analysis was conducted to determine the relationship between total system costs, electricity generation revenue, and VRE penetration. Figure 40 shows the calculation diagram of the proposed methodology.

5.1.2.3 Calculation of generating revenue from the capacity market

The revenue of electricity generation in the capacity market depends on the capacity market clearing prices and the *FCAP* of the generator. The capacity market clearing price is calculated by capacity market simulation. The capacity market is assumed to be clear annually, where the demand is the summation of the year's peak demand and the PRM, as shown in equation (63). The supply curve of each year is formed by the bidding price of the generator calculated as equation (64). This method assumes that all investors bid annually. The capacity market thus ensures a payment at the level of the auction clearing price over a year. Therefore, This method calculates the profit of the generator from the energy market and, in case the profit is negative, each project bids the annual payment $Bid_{n,y}^{CM}$ necessary to increase the negative profit to 0. If the project is already positive without a capacity market, the investor bids 0, as shown in equation (65). This method assumes no strategic bidding in the capacity market.

$$D_y^{cap} = Peak_y + PRM \tag{63}$$

$$(-C_{n,y} \times ICAP_n) + (profit_{n,y}^{EM}) + (Bid_{n,y}^{CM} \times FCAP_n) = 0 \tag{64}$$

$$Bid_{n,y}^{CM} = \max\left(0, \frac{(C_{n,y} \times ICAP_n) - (profit_{n,y}^{EM})}{FCAP_n}\right) \tag{65}$$

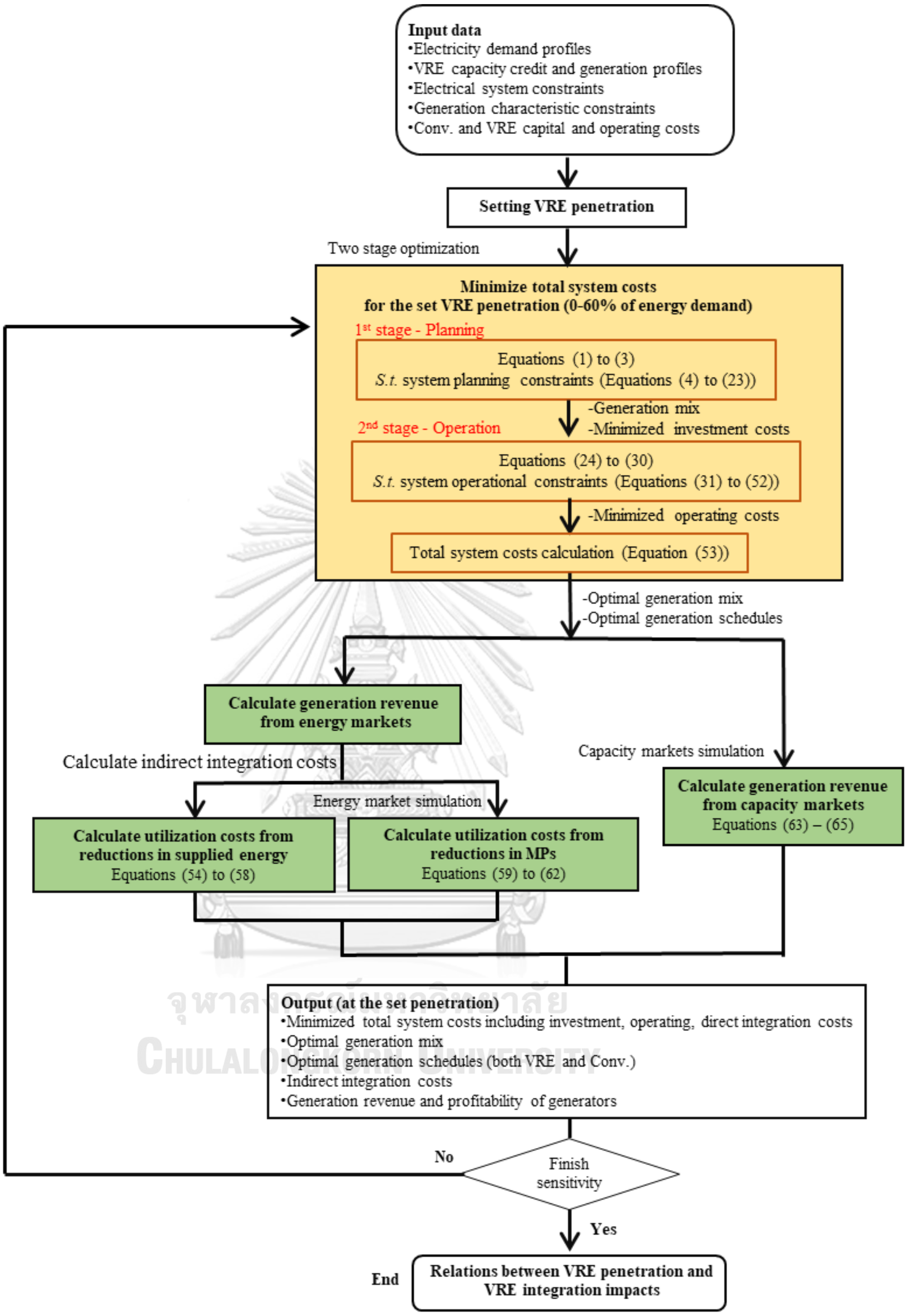


Figure 40 The calculation diagram of the proposed methodology.

5.2 VRE impacts mitigation

This dissertation proposes two approaches to mitigate the VRE integration impacts on total system costs and electricity generation revenue, considering system and market aspects.

5.2.1 VRE impacts mitigation by enhancing system flexibility

The VRE impact mitigation is determined by enhancing electrical system flexibility. According to [68], the three key features of operational flexibility are:

- **Minimal load:** The lower the minimum load, the larger the range of generation capacity. A low minimum load can also avoid expensive start-ups and shutdowns. However, at minimum load, the power plant operates at lower efficiency. The lower the load, the more difficult it is to ensure stable combustion without supplemental firing.
- **Start-up time**: The shorter the start-up time, the quicker a power plant reaches its minimum load. Nonetheless, faster start-up times put greater thermal stress on components, reducing their lifetime. The limitation of start-up time is the allowable thermal gradient for components.
- **Ramp rate:** A higher ramp rate allows a power plant operator to adjust net output more rapidly. Nevertheless, rapid change in firing temperature results in thermal stress. The ramp rate limitations are allowable thermal stress and unsymmetrical deformations, storage behavior of the steam generator, quality of fuel used, and the time lag between coal milling and turbine response.

The generator characteristics were changed in Table 10.

Table 10 Operating parameters of different technologies to improve system flexibility.

Technology	Key operating parameters		
	Minimum generation (% of capacity)	Ramp rate (MW/minute)	Warm start time (hours)
CCGT	30%	56	0.5
Coal	20%	60	2.6
Hydro	-	-	-

Sources: IEA (2017d), Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations; NREL (2012), Power Plant Cycling Cost; Gonzalez-Salazar et al. (2018), Review of the Operational Flexibility and Emissions of Gas- and Coal-Fired Power Plants in a Future with Growing Renewables; Siemens (2017), Flexibility of Coal- and Gas-Fired Power Plants; Agora Energiewende (2017), Flexibility in Thermal Power Plants – With a Focus On Existing Coal-Fired Power Plants.

5.2.2 VRE impacts mitigation by using a bidding strategy

The VRE impacts mitigation is determined by using a method to find the VRE generation schedules that maximize the profits of VRE generators. Physical withholding strategy is applied to the method to the VRE generation schedules that maximize the profits of VRE generators while considering the trade-off among the amount of VRE output, the MPs, and the SOCs. The VRE support schemes involving the prices of VRE offered to the market were considered. The method is the combination of the merit-order model and the unit-commitment model. The first model is for optimizing VRE output, and the second one is for satisfying the SOCs. The traditional method to maximize VRE generators' profits, which is the maximization of VRE output, was also demonstrated to compare the VRE profit with the one from the proposed method. Note that this dissertation focus on the day-ahead market.

5.2.1.1 The Merit-Order Model

The merit-order model simulates the operation of energy markets for various cases. In energy markets with theoretically perfect competition, generators offer two parameters to the markets at a specific time: first, their capability to produce energy; second, the price they would like to sell their energy at. Generators will offer the lowest price they can accept without loss to make sure that they can be committed to selling the energy [36]. Those offers determine the merit-order curve over time. The MPs at that time are then set by the intersection of the merit-order curve and the electricity demand. No market participant can affect the MPs [98]. However, in real-life situations, generators could use strategies to drive up MPs to gain more market profit. First, they could curtail their output (offered less energy). Second, they could offer to sell their energy at high prices. These two different approaches lead to the same results: higher MPs, higher profits, and withheld output [37, 38]. This dissertation applied the first approach into the merit-order model to illustrate the relationship between VRE output and MPs. Additionally, the VRE support schemes involving the prices VRE offered to the market were included in the model. Figure 41 demonstrates the concept of the merit-order model.

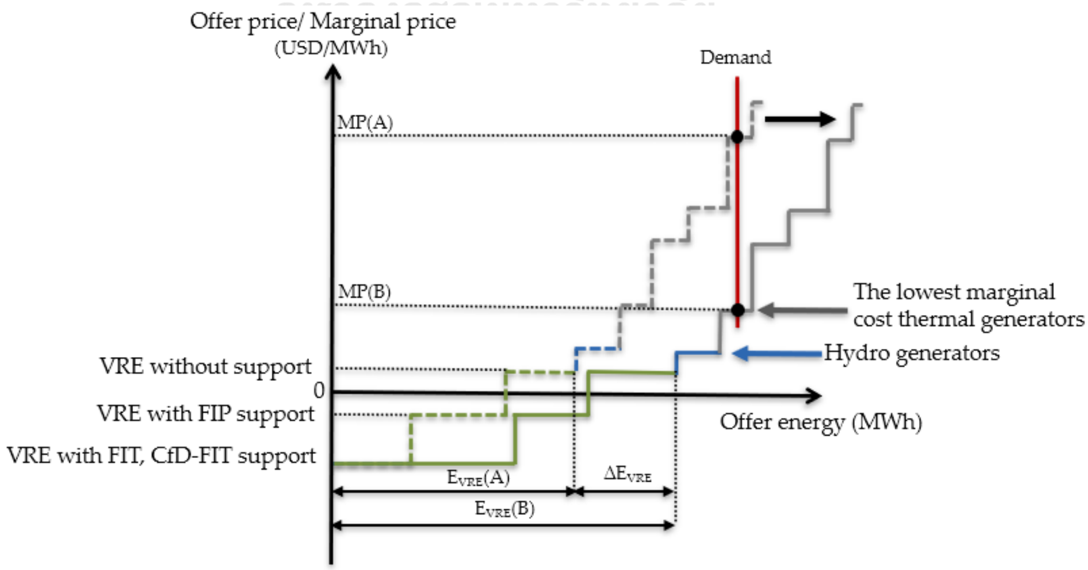


Figure 41 The concept of the merit-order model.

In Figure 41, the support schemes are classified into two types: FIP schemes, where VRE generators receive the fixed support price on top of the MPs and FIT and CFD-FIT schemes, where VRE generators receive only the fixed price. Both types of supported VRE generators will offer negative prices equal to their support prices. VRE generators without support will offer their MCs. This strategy guarantees that they can be committed to selling the energy. Moreover, even if they are the last power plant committed to supplying energy (marginal unit), the MPs will be at least equal to their support prices (if they are supported) or MCs (if they are not supported). Therefore, their revenue from MPs and support schemes is at least zero. That means no negative revenue from selling energy is possible.

At a specific time, the MPs depend on the electricity demands at that time, the energy offered by the VRE (E_{VRE}), the energy offered by other generators, and the prices offered by all other generators. Note that this dissertation focuses on the relationship of VRE output and MPs. Thus, other parameters involved in MPs, such as all thermal and hydro generators' energy offers and price, were assumed to be fixed. Their collective offered energy was assumed to be the maximum energy they could provide, and their offered prices were assumed to be their MCs at their maximum capability. Lastly, consumers were assumed not to react to the MPs. In Figure 41, if VRE-offered energy is increased from $E_{VRE}(A)$ to $E_{VRE}(B)$, the merit-order curve will be shifted to the right. The MPs will decline from MP(A) to MP(B). E_{VRE} always affects the MP regardless of the support schemes the VRE generators receive because they shift the merit-order curve. Thus, a greater E_{VRE}, contributes to a greater drop in MPs (MOE), whereas a low E_{VRE} means generators sell less electricity. As a result, if generators offer the optimal E_{VRE} into the markets, they will gain the maximum profits.

In the merit-order model, the objective function is the maximization of daily VRE profit. The optimal VRE generation schedules of a considered day are determined at a resolution of one hour. The total profits of all VRE generators are maximized, rather than the profits of each individual generator to avoid sub-optimal results. All VRE generators in the system are classified into two groups based on their resources, i.e., solar and wind. Thus, any parameters relevant to VRE in this dissertation refer to the total values of all solar or wind generators in the system.

The VRE generators' daily profits are calculated by summing the generators' hourly revenues (*Revenue*(t)), and subtracting the generators' hourly variable costs (*VC*(t)) as shown in Equation (66); t is a specific time.

$$
\begin{aligned}
Max\,(&(\sum_{t=1}^{T} Revenue_d^{Solar}(t) - \sum_{t=1}^{T} VC_d^{Solar}(t)) \\
&+ (\sum_{t=1}^{T} Revenue_d^{Wind}(t) - \sum_{t=1}^{T} VC_d^{Wind}(t)))
\end{aligned}
\tag{66}
$$

As shown in Figure 23, VRE generators that receive no support scheme will gain their revenue only from the MPs. FIP-supported VRE generators will earn their revenue from the MPs and the FIP support price (SP_{FIP}). FIT and CFD-FIT supported VRE generators will gain their revenue only from the FIT support price (SP_{FIT}). Both SP_{FIP} and SP_{FIT} are constants. The *Revenue*(t) is determined by summation of the MPs and the support schemes (if any) multiplied by the VRE output ($E(t)$). The $Revenue(t)$ calculations differentiated by VRE support schemes and resources are shown in Equations (67) and (68). The $\lambda(t)$ is the function of the merit-order curve and electricity demand ($D(t)$) at a specific time, as shown in Equation (69).

$$Revenue_d^{Solar}(t) = \begin{cases} \lambda_d(t) \times E_d^{Solar}(t) & ; \ \textit{Solar generators without support} \ ; \forall t \in T \\ (\lambda_d(t) + SP_{FIP}^{Solar}) \times E_d^{Solar}(t) & ; \ \textit{Solar generators with FIP support} \ ; \forall t \in T \\ SP_{FIT}^{Solar} \times E_d^{Solar}(t) & ; \ \textit{Solar generators with FIT support} \ ; \forall t \in T \end{cases} \tag{67}$$

$$Revenue_d^{Wind}(t) = \begin{cases} \lambda_d(t) \times E_d^{Wind}(t) & ; \ \textit{Wind generators without support} \ ; \forall t \in T \\ (\lambda_d(t) + SP_{FIP}^{Wind}) \times E_d^{Wind}(t) & ; \ \textit{Wind generators with FIP support} \ ; \forall t \in T \\ SP_{FIT}^{Wind} \times E_d^{Wind}(t) & ; \ \textit{Wind generators with FIT support} \ ; \forall t \in T \end{cases} \tag{68}$$

$$\lambda_d(t) = \textit{Merit-order curve}(D_d(t)) \ ; \forall t \in T \tag{69}$$

The $VC(t)$ is the generators' hourly variable costs calculated by multiplying their marginal costs (MC) and their $E(t)$, as shown in Equations (70) and (71).

$$VC_d^{Solar}(t) = MC_{Solar} \times E_d^{Solar}(t) \ ; \forall t \in T \tag{70}$$

$$VC_d^{Wind}(t) = MC_{Wind} \times E_d^{Wind}(t) \ ; \forall t \in T \tag{71}$$

The objective function is optimized, subject to the VRE resource constraints. The $E(t)$ has to be less than or equal to the VRE generation capability at the time ($Pr(t)$), which is determined by the available solar irradiance and wind speed, multiplied by the installed capacity ($ICAP$), which are the results of section 5.1.1, as shown in Equations (72) and (73).

$$E_d^{Solar}(t) \le ICAP^{Solar} \times Pr_s^{Solar}(t) \ ; \forall t \in T \tag{72}$$

$$E_d^{Wind}(t) \le ICAP^{Wind} \times Pr_s^{Wind}(t) \ ; \forall t \in T \tag{73}$$

The outputs from the merit-order model are $E^{Solar}(t)$ and $E^{Wind}(t)$, which are the VRE outputs offered to the markets that provide the maximum profit to VRE generators. The time series of the VRE output during the day is herein referred to as the VRE strategic schedule. The merit-order model consisting of nonlinear multivariable functions was solved by the optimization tool "Fmincon" in MATLAB. Fmincon has an interior-point algorithm that can handle various types of nonlinear problems. Moreover, the algorithm uses little memory and can solve large problems quickly [104].

5.2.2.2 The Unit-Commitment Model

After getting the VRE strategic schedules from the merit-order model, the unit-commitment model was then used to find whether SOCs can be satisfied when VRE supplies energy following the VRE strategic schedules. If the VRE strategic schedules contribute to the unsatisfiable SOCs in some period during the day, VRE strategic schedules will be modified by curtailing the output at the time.

The objective function of the unit-commitment model is based on the unit commitment problem (UCP) with a resolution of one hour. The UPC minimizes the daily *VC* of all thermal hydropower plants incurred from supply energy to demand, as shown in Equation (74). After getting the VRE strategic schedules from the merit-order model, the unit-commitment model was then used to find whether SOCs can be satisfied when VRE supplies energy following the VRE strategic schedules, as shown in Equations (75) and (76). n is a given power plant, $N_{thermal}$ is the total number of thermal power plants in the system, and N_{Hydro} is the total number of hydropower plants in the system.

$$\mathrm{Min}\left(\sum_{t=1}^{T}\left(\sum_{n}^{N_{Thermal}} VC_{n,d}^{Thermal}(t)+\sum_{n}^{N_{Hydro}} VC_{n,d}^{Hydro}(t)+VC_{n,d}^{Solar}(t)+VC_{n,d}^{Wind}(t)\right)\right) \tag{74}$$

$$E_{d}^{Solar,sell}(t)\leq E_{d}^{Solar,strategy}(t)\ ;\ \forall t\in T \tag{75}$$

$$E_{d}^{Wind,sell}(t)\leq E_{d}^{Wind,strategy}(t)\ ;\ \forall t\in T \tag{76}$$

The $VC(t)$ is calculated from the generators' MCs multiplied by their $E(t)$. The calculation of the $VC(t)$ of hydropower plants, and the $VC(t)$ of thermal power plants are the same as shown in equations (26) and (29), respectively.

The objective function is optimized, subject to the SOCs: firstly, electrical system constraints such as serving electricity demand, committing must-run units, and providing operating reserve requirements that cover demand and VRE forecast errors, along with spinning reserves requirement for contingency events fixed by the N-1 approach; second, generation characteristic constraints, i.e., minimum/maximum generation, ramp capability, minimum up/downtime, and the limitations of hydro units which depend on the amount of water reserved on the considered day. All the constraints are the same as shown in equations (31) – (52). The UCP is defined to be mixed-integer programming (MIP) because it can address issues with non-convexity related to the SOCs [40]. The UCP, which is a mixed-integer linear function was solved by the mixed-integer linear programming optimization tool "Intlinprog" in MATLAB.

The outputs from the combination of the merit-order model and the unit-commitment model are optimal VRE generation schedules that provide the maximum VRE profits while considering the trade-off among the amount of VRE output, the MPs, and the SOCs. The MPs and VRE generators' profits are then determined according to the schedules. The proposed method outputs are the optimal VRE generation schedules, the MPs, and the VRE generators' consistent profits. However, it is essential to note that this dissertation focuses on the bidding strategy in the day-ahead energy market. There are other markets, such as the intraday market, that the generators should consider to assess their total revenue and design their strategies.

Later, the outputs from the bidding strategy method and the benchmark cases were compared. Figure 42 shows the flow chart of the optimization and sensitivity analysis.

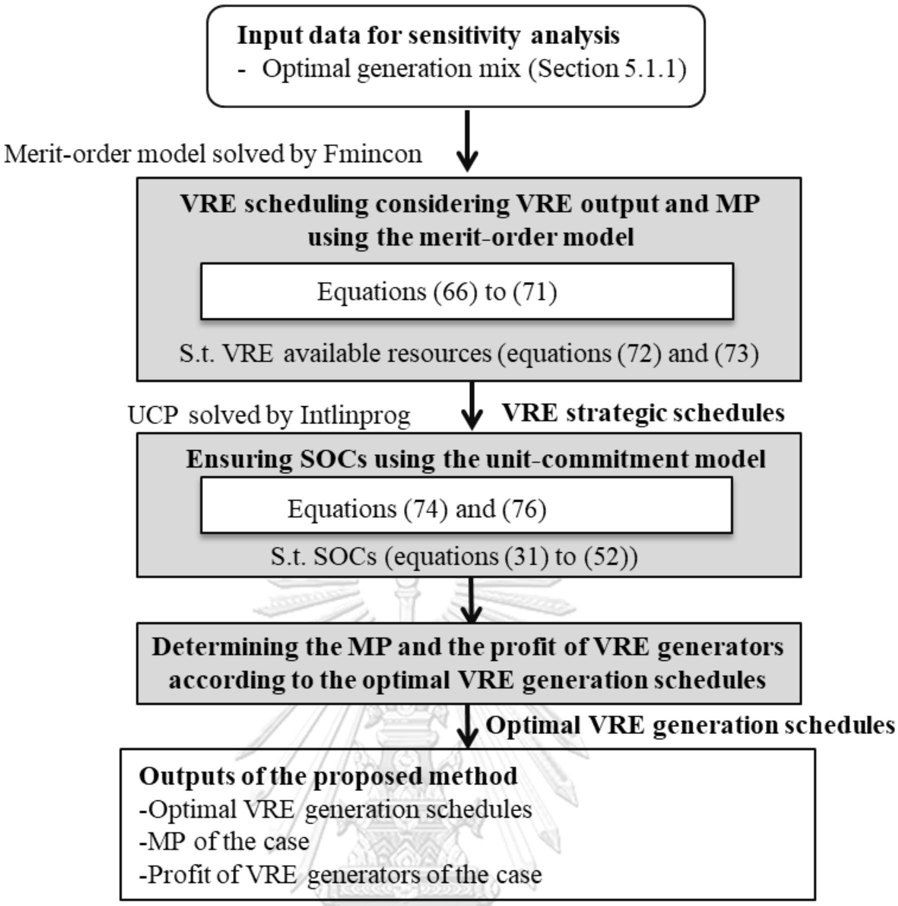


Figure 42 Flow chart of the optimization and sensitivity analysis.

Chapter 6
Data and assumptions

This dissertation used Thailand's electrical system as the test system. Although the system is a system with a vertical structure, this dissertation assumed it as a liberalized structure. The planning horizon is 2022 to 2042. The electricity demand profiles on the representative days at the start planning year (2022) are shown in Figure 43 and Figure 44[105]. Table 11 shows the projection of electricity demand from 2022 to 2042. Figure 45 and Figure 46 show the VRE generation profiles where the forecast error of solar is around 12-16.6% in the daytime, while the wind is 6.7-12.4% (Mean Absolute Percentage Error, MAPE) [105]. The installed capacity of small power producers (SPP) and other electricity sources throughout the planning horizon are shown in Table 12 and Table 13[2, 106]. Both are non-dispatchable, and their generation profiles do not depend on unit commitment. The electricity demand profiles in Figure 43 and Figure 44 are the electricity demand of EGAT, which is Thailand's TSO. Thus, it has accounted for the electricity supplied by VRE connected in the distribution system. Before starting the algorithm in chapter 5, this dissertation needs to set zero the existing VRE, the existing 3,086 MW of solar and 1,504 MW of wind were re-added to the electricity demand. Moreover, the electricity demand profiles were then diminished by self-consumption and the electricity provided by SPP, and other electricity sources. The results are the electricity demand profiles that have to be served by VRE and conventional generation used in the algorithm.

For the system planning constraints, this dissertation assumed the PRM requirement to be 15% of the peak demand of the considered year [18]. Moreover, this dissertation assumed there was no limitation of CCGT generation installation, while there were limitations for annual hydro generation and coal generation installation, as shown in Table 14. This dissertation assumed that the conventional generation configuration was reconsidered every five years to reduce calculation burdens. Thus, the number of generators in the system depends on the considering period. The increase in VRE installation has a limitation of 4.48 GW of solar and 1.94 GW of wind per year. The data was estimated from the data in [1]. For the system operational constraints, each conventional power plant's characteristics differ depending on the individual configuration. Table 15 shows the characteristics of thermal generation in 2022, while Table 16 shows the characteristics of hydro generation in 2022[105]. Assume that any generators installed throughout the planning horizon have average characteristics of the existing generators in 2022.

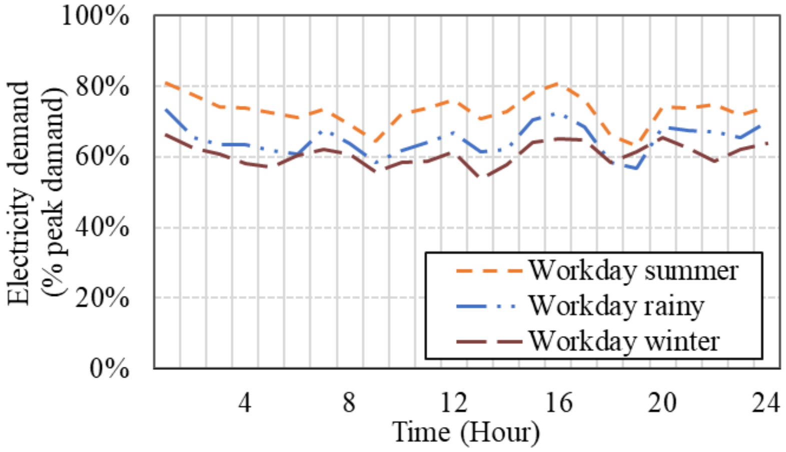


Figure 43 Load profiles of workdays.

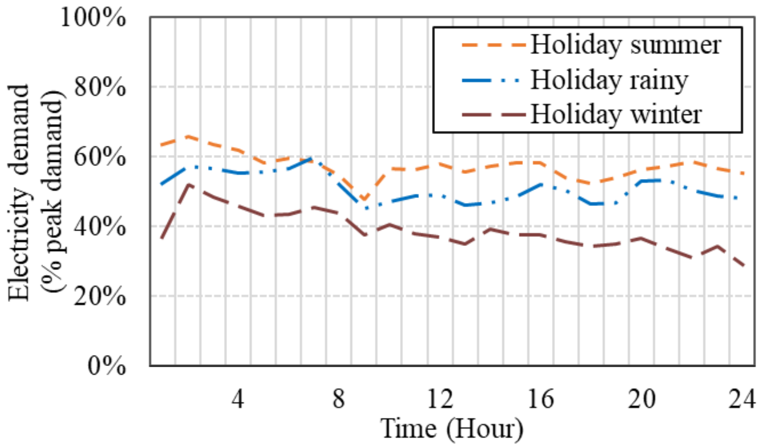


Figure 44 Load profiles of holidays.

Table 11 The projection of electricity demand from 2022 to 2042.

Year of the planning horizon	Year	Peak demand (MW)
Present	2022	35,213
1st	2023	36,390
2nd	2024	37,610
3rd	2025	38,780
4th	2026	39,933
5th	2027	41,079
6th	2028	42,267
7th	2029	43,541
8th	2030	44,781
9th	2031	46,054
10th	2032	47,303
11th	2033	48,627
12th	2034	49,921

Year of the planning horizon	Year	Peak demand (MW)
13th	2035	51,265
14th	2036	52,609
15th	2037	53,997
16th	2038	55,697*
17th	2039	57,451*
18th	2040	59,260*
19th	2041	61,126*
20th	2042	63,051*

*Predicted from the trend

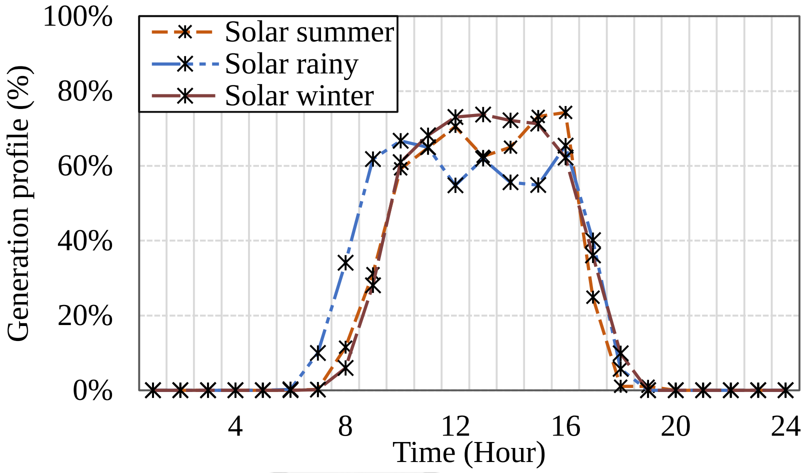


Figure 45 Solar generation profiles.

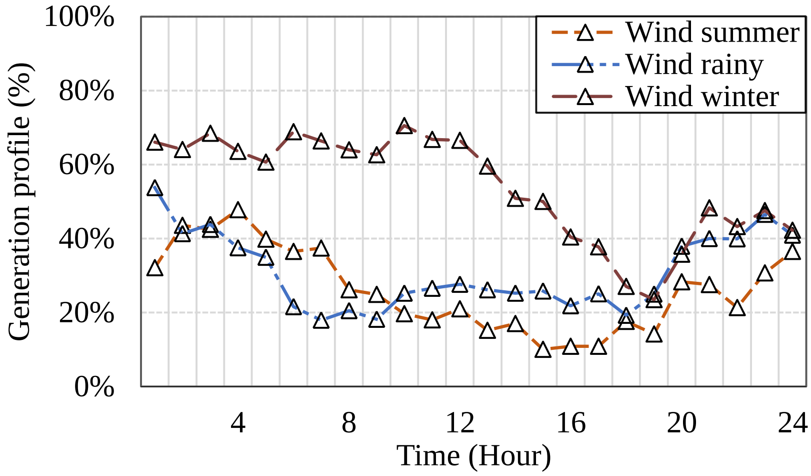


Figure 46 Wind generation profiles.

Table 12 The projection of small power producers' installed capacity in the test system (MW).

Year	Firm – Gas (Cogen)	Firm – Coal (Cogen)	RE Hybrid firm	Non firm – Coal	Non firm – Gas	Firm and non firm – Biomass	Firm and non firm – Waste
2022	5,160	370	764	8	270	1,227	180
2023	5,954	370	764	8	270	1,227	180
2024	5,744	190	715	8	270	1,227	180
2025	5,684	130	659	8	270	1,227	180
2026	5,684	130	654	8	270	1,227	180
2027	5,684	130	654	8	270	1,227	180
2028	5,684	130	551	8	270	1,227	180
2029	5,684	130	551	8	270	1,227	180
2030	5,684	130	551	8	270	1,227	180
2031	5,684	130	510	8	270	1,227	180
2032	5,684	130	502	8	270	1,227	180
2033	5,684	130	502	8	270	1,227	180
2034	5,684	130	481	8	270	1,227	180
2035	5,594	130	481	8	270	1,227	180
2036	5,594	130	481	8	270	1,227	180
2037	5,340	130	467	8	270	1,227	180
2038	5,340	130	467	8	270	1,227	180
2039	5,340	130	467	8	270	1,227	180
2040	5,340	130	467	8	270	1,227	180
2041	5,340	130	467	8	270	1,227	180
2042	5,340	130	467	8	270	1,227	180

Table 13 The projection of other electricity sources' installed capacity in the test system (MW).

Year	Thermal generation (fuel oil))	Diesel generation	Interconnection	Energy conservation measure
2022	315	60	300	0
2023	315	60	300	0
2024	315	60	300	0
2025	315	60	300	0
2026	315	60	300	0
2027	315	60	300	0
2028	315	60	300	0
2029	315	60	300	0
2030	315	60	300	0
2031	315	60	300	0
2032	315	60	300	354
2033	315	60	300	556

Year	Thermal generation (fuel oil))	Diesel generation	Interconnection	Energy conservation measure
2034	0	60	300	1,415
2035	0	60	300	2,440
2036	0	60	300	3,300
2037	0	60	300	4,000
2038	0	60	300	4,000
2039	0	60	300	4,000
2040	0	60	300	4,000
2041	0	60	300	4,000
2042	0	60	300	4,000

Table 14 The projection of coal and hydro generators' installed capacity limitation (MW).

Year	Hydro	Coal
2022	8,380	5,160
2023	8,380	5,160
2024	8,380	5,160
2025	8,380	4,080
2026	9,080	4,950
2027	9,080	5,220
2028	9,780	5,220
2029	9,654	5,220
2030	9,654	5,220
2031	9,654	5,220
2032	10,354	3,873
2033	11,054	3,873
2034	11,054	3,873
2035	10,806	3,873
2036	10,806	3,873
2037	10,806	3,213
2038	10,806	3,213
2039	10,806	3,213
2040	10,806	3,213
2041	10,806	3,213
2042	10,806	3,213

Table 15 Thermal power plant characteristics (in 2022).

Type of generation	Installed capacity (MW)	Min. Power (%FL[1])	Ramp up (%FL/Hr.)	Ramp down (%FL/Hr.)	Min. Uptime (Hr.)	Min. Downtime (Hr.)	Start time (Hot) (Hr.)
CCGT1	710.00	57.75	100.00	100.00	1	1	3
CCGT2	710.00	57.75	100.00	100.00	1	1	3
CCGT3	1,600.00	58.00	100.00	100.00	1	1	2
CCGT4	1,468.00	56.40	100.00	100.00	1	2	2

Type of generation	Installed capacity (MW)	Min. Power (%FL[1])	Ramp up (%FL/Hr.)	Ramp down (%FL/Hr.)	Min. Uptime (Hr.)	Min. Downtime (Hr.)	Start time (Hot) (Hr.)
CCGT5	700.00	50.00	100.00	25.71	2	1	3
CCGT6	1,600.00	58.00	100.00	100.00	1	1	2
CCGT7	670.00	64.18	100.00	100.00	1	1	8
CCGT8	650.00	55.38	100.00	100.00	4	5	6
CCGT9	2,041.00	72.02	79.37	79.37	5	2	6
CCGT10	1,400.00	70.00	100.00	100.00	2	1	3
CCGT11	1,290.00	68.60	100.00	100.00	2	1	3
CCGT12	1,436.00	55.01	100.00	100.00	1	1	5
CCGT13[2]	766.00	60.57	100.00	100.00	1	1	3
CCGT14	930.00	58.06	100.00	64.52	1	1	2
CCGT15	350.00	57.14	100.00	100.00	2	4	2
CCGT16	713.00	58.91	100.00	100.00	2	4	2
CCGT17	828.00	61.35	100.00	100.00	1	2	3
CCGT18	1,220.00	60.66	100.00	100.00	1	1	3
Coal1	315.00	26.98	64.76	64.76	4	24	4
Coal2	1,346.50	23.91	80.21	100.00	4	2	3
Coal3	1,051.00	53.28	57.09	57.09	23	23	7
Coal4	1,152.00	48.61	52.08	52.08	23	23	18
Coal5	660.00	31.82	100.00	100.00	4	2	2
Coal6	1,473.00	50.07	100.00	100.00	2	5	2
Coal7	600.00	30.00	100.00	100.00	2	2	4
Coal8	1,620.00	30.00	55.56	55.56	23	23	3

[1] %FL means the percentage of full-load generation.
[2] The must-run unit.

Table 16 Hydro power plant characteristics (in 2022).

Type of generation	Installed capacity (MW)	Min. Power (%FL[1])	Ramp up (%FL/Hr.)	Ramp down (%FL/Hr.)	Min. Uptime (Hr.)	Min. Downtime (Hr.)	Plant Factor
Hydro1	432.00	55.56	100.00	100.00	0	0	0.23
Hydro2	230.00	56.67	100.00	100.00	0	0	0.23
Hydro3	72.00	70.83	100.00	100.00	0	0	0.36
Hydro4	500.00	72.00	100.00	100.00	0	0	0.08
Hydro5	240.00	75.00	100.00	100.00	0	0	0.24
Hydro6	448.00	80.36	100.00	100.00	0	0	0.26
Hydro7	360.00	66.67	100.00	100.00	0	0	0.18
Hydro8	360.00	83.33	100.00	100.00	1	1	0.18
Hydro9	37.60	42.55	100.00	100.00	0	0	0.54
Hydro10	276.00	65.22	100.00	100.00	0	0	0.33
Hydro11	126.00	100.00	100.00	100.00	0	0	0.38
Hydro12	597.00	75.38	100.00	100.00	0	0	0.42
Hydro13	272.80	51.25	100.00	100.00	0	0	0.61
Hydro14	960.00	62.50	100.00	100.00	0	0	0.68
Hydro15	368.40	42.59	100.00	100.00	0	0	0.51
Hydro16	1,233.40	50.00	100.00	100.00	0	0	0.53
Hydro17	214.00	86.91	100.00	100.00	0	0	0.74
Hydro18	220.00	84.45	100.00	100.00	0	0	0.74

[1] %FL means the percentage of full-load generation.

The capital costs and lifetime of the power plants are shown in Table 17. The data were provided by [107]. The operating costs of the power plants, i.e., variable costs and startup costs are shown in Table 18 and Table 19. Table 20 shows the projection of generators' installation and operation costs, the data is from [108]. This dissertation assumes the discount rate to be 10%. Note that Thailand is Non-OECD country, if the method is used for OECD country the discount rate would be 7% [109].

Table 17 The capital costs of power plants in 2022 and their lifetime.

Type of generation	Capital costs ($/kW)	Lifetime
CCGT	1,168	30
Coal	2,032	40
Hydro	4,250	80
Solar	992	25
Wind	2045	25

Table 18 The operating costs of the thermal power plants.

Type of generation	Variable costs[1]						Startup costs[1] ($/MWinstalled)
	MC^1 ($/MWh)	MC^2 ($/MWh)	MC^3 ($/MWh)	P^{R1} (%FL)	P^{R2} (%FL)	P^{R3} (%FL)	
CCGT1	56.34	54.03	52.87	74.93	83.94	100.00	34.34
CCGT2	54.21	54.14	54.10	57.75	57.76	100.00	68.66
CCGT3	54.39	52.54	51.31	70.00	80.00	100.00	22.87
CCGT4	56.90	54.39	53.22	74.93	83.92	100.00	105.53
CCGT5	55.83	52.96	52.69	72.86	92.86	100.00	60.62
CCGT6	54.39	52.54	51.31	70.00	80.00	100.00	45.74
CCGT7	60.29	58.56	57.30	74.93	83.88	100.00	41.55
CCGT8	40.72	38.51	37.52	69.54	82.77	100.00	39.77
CCGT9	60.15	59.43	58.71	83.59	83.60	100.00	55.02
CCGT10	60.84	59.96	59.07	82.43	82.44	100.00	30.84
CCGT11	55.94	54.28	53.12	79.46	88.06	100.00	39.04
CCGT12	52.96	52.96	50.74	71.66	91.91	114.60	40.90
CCGT13	53.11	51.82	50.52	79.63	79.66	100.00	83.62
CCGT14	52.95	50.16	49.44	70.00	90.00	100.00	46.32
CCGT15	53.81	52.71	51.61	91.79	91.81	100.00	46.49
CCGT16	56.40	56.33	56.29	58.92	58.93	100.00	21.61
CCGT17	57.42	56.08	54.73	79.71	79.73	100.00	76.09
CCGT18	52.40	52.32	52.26	60.66	60.67	100.00	8.39
Coal1	151.63	145.13	142.18	53.97	79.37	100.00	20.17
Coal2	33.25	33.22	33.20	23.92	23.93	100.00	42.47
Coal3	111.58	110.37	109.17	74.73	74.75	100.00	10.30
Coal4	73.99	72.94	71.89	75.00	75.02	100.00	7.08
Coal5	36.83	35.18	33.52	79.77	79.79	100.00	45.51
Coal6	24.53	23.58	22.62	95.72	95.74	100.00	63.31
Coal7	21.54	19.51	19.07	60.00	80.00	100.00	0.00
Coal8	22.54	22.22	21.91	85.93	85.96	100.00	0.00

[1] Variable costs, startup costs (assumed to be all hot start) of CCGT, and coal were provided by [105]. The exchange rate THB/USD is 33/1 (on 4th February 2021).

Table 19 The operating costs of the hydro and VRE power plants.

Type of generation	Variable cost[1] ($/MWh)
Hydro	14.48
Solar	7.46
Wind	10.105

[1] The data were from [107]. The exchange rate THB/USD is 33/1 (on 4th February 2021).

Table 20 The projection of generators' installation and operation costs (% of the costs in 2022).

Year	Solar		Wind		Hydro		CCGT		Coal	
	Inv.	O&M	Inv.	O&M	Inv.	O&M	Inv.	Fuel, O&M	Inv.	Fuel, O&M
2030	-41.49%	-12.50%	-7.00%	0.00%	0.00%	0.00%	0.00%	24.55%	0.00%	48.47%
2050	-60.56%	-12.50%	-11.88%	-8.33%	0.00%	0.00%	0.00%	39.06%	0.00%	98.50%

For the reserve margin calculation mentioned in chapter 5, Figure 47 and Figure 48 show the possible range of capacity credits of VRE collected from the literature [110-113]. The VRE capacity credits are different depending on the region. This dissertation used the average of the data. Table 21 shows the simplified firm capacity of generation.

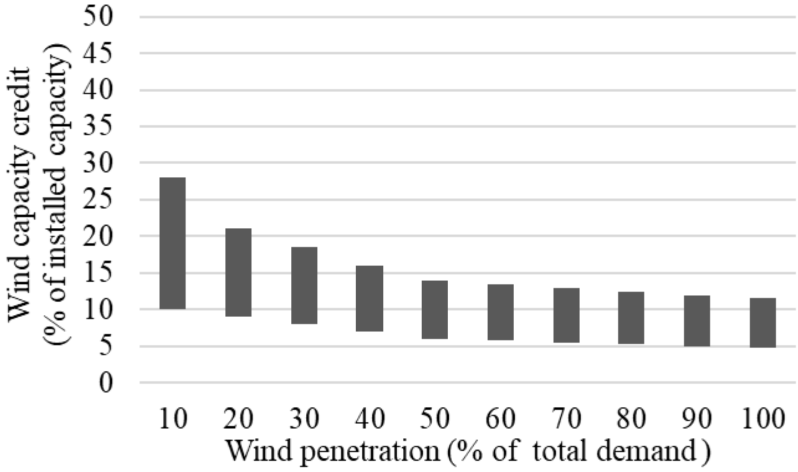


Figure 47 Wind capacity credit.

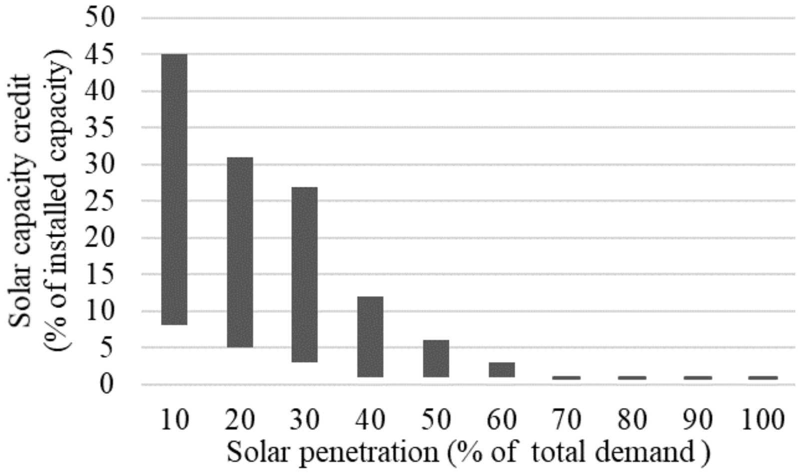


Figure 48 Solar capacity credit.

Table 21 The simplified firm capacity of generation.

Type of generation	Firm capacity (%)
CCGT	98.77%[1]
Coal	95.46%[1]
Hydro	100%[2]
SPP Firm and non firm – Biomass	52%[2]
SPP Firm and non firm – Waste	52%[2]
Other SPP and electricity sources	Equal to installed capacity

[1] Calculated from averaged forced outage rate (FOR) provided by [105].
[2] Equal to the generation dependable capacity. The data were from [2].

The VRE support schemes prices of many countries are collected in Figure 49 to Figure 52 [51, 54-57]. Some countries provide different prices depending on the installed capacity of individual generators, and some proportions are substantially higher or lower than the others; thus, this dissertation calculated the medians of the data and used them as the VRE support schemes' prices for the calculation. The medians of the data: $SP_{FIT,Wind}$, 91.24 \$/MWh. $SP_{FIT,Solar}$, 127.73 \$/MWh. $SP_{FIP,Wind}$, 64.47 \$/MWh. $SP_{FIP,Solar}$, 114.41 \$/MWh.

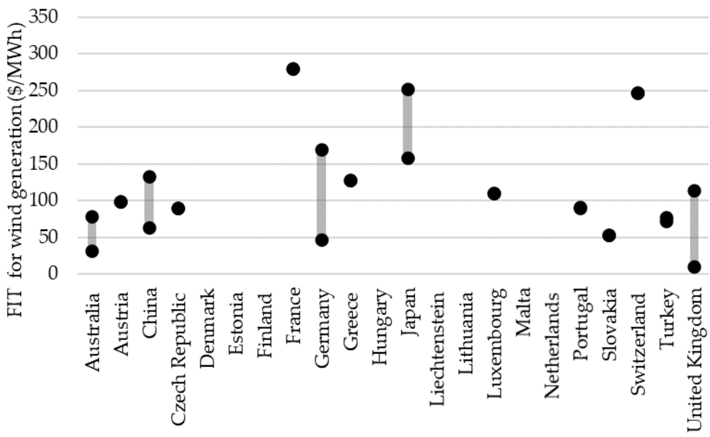


Figure 49 FIT for wind generation data.

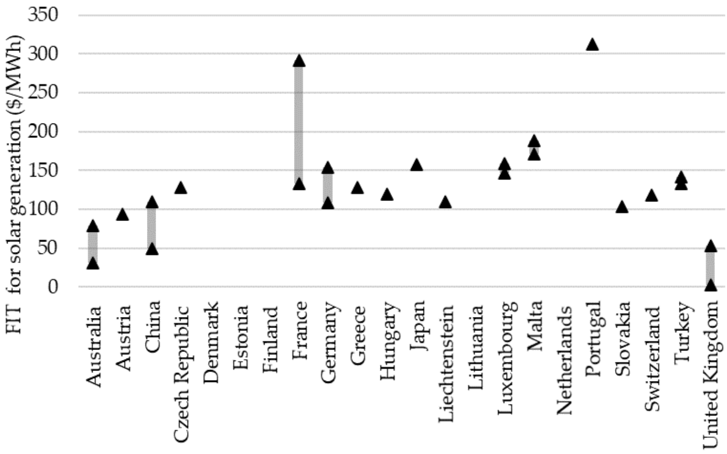


Figure 50 FIT for solar generation data.

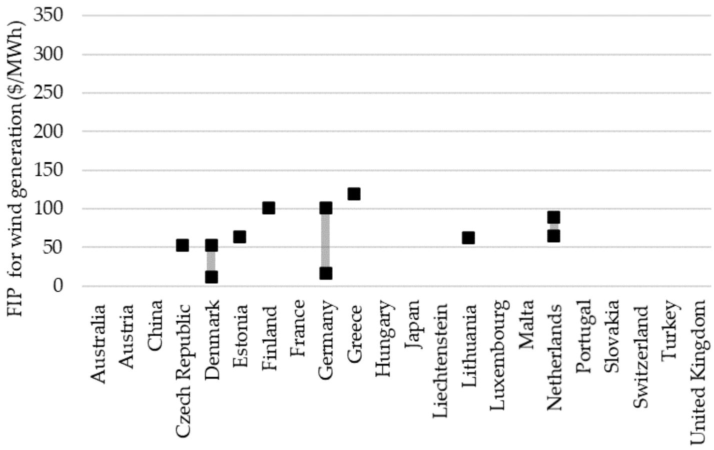


Figure 51 FIP for wind generation data.

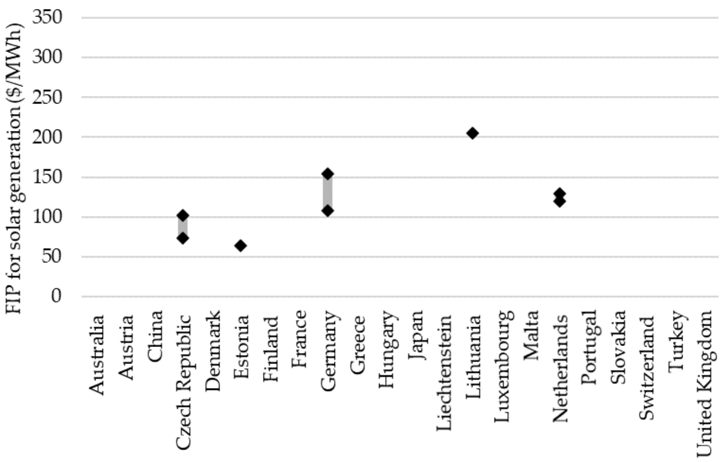


Figure 52 FIP for solar generation data.

Chapter 7

Results and discussion

This chapter presents results and discussions. Section 7.1 shows the impacts of VRE integration by performing the methods in Section 5.1. Section 7.2 shows the results of VRE impacts mitigation by performing the methods in Section 5.2.

7.1 The impacts of VRE integration on total system costs and electricity generation revenue

The proposed methodology in Section 5.1 was simulated to determine the impacts of VRE integration on total system costs and electricity generation revenue before mitigation. The optimal generation mix and the impacts of VRE integration on total system costs are shown in Sections 7.1.1. The impacts of VRE integration on electricity generation revenue are shown in Section 7.1.2

7.1.1 The impacts of VRE integration on total system costs

The optimal generation mix of the system every year was determined using the proposed method. Table 22 shows the optimal generation mix at a specific VRE penetration throughout the planning horizon. The VRE penetration were varied from 0-60% of total energy consumption. Note that VRE integration of more than 60% within the end of considering period is not possible because annual increasing VRE installation is limited. Figure 53 shows the optimal generation mix at the end of the planning horizon at a specific VRE penetration. VRE share increased by VRE penetration, whereas those of the conventional generation were hardly changed by VRE penetration level. This is because no matter how many VRE generators will be 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 guarantee the adequacy of PRM.

Table 22 The optimal generation mix throughout the planning horizon at a specific VRE penetration (GW)

L_{VRE}	Type	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
20%	Solar	3	8	12	17	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
	Wind	2	3	5	7	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
	Hydro	8	8	8	8	9	9	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
	CCGT	20	21	22	24	23	24	25	27	28	29	31	32	33	34	34	36	38	40	42	44	46
	Coal	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3
30%	Solar	3	8	12	17	21	26	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
	Wind	2	3	5	7	9	11	13	15	15	15	15	15	15	15	15	15	15	15	15	15	15
	Hydro	8	8	8	8	9	9	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
	CCGT	20	21	22	24	24	25	25	26	28	29	31	32	33	33	34	36	38	40	42	44	46
	Coal	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3
40%	Solar	3	8	12	17	21	26	30	35	37	37	37	37	37	37	37	37	37	37	37	37	37
	Wind	2	3	5	7	9	11	13	15	17	19	21	21	21	21	21	21	21	21	21	21	21
	Hydro	8	8	8	8	9	9	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
	CCGT	20	21	22	24	24	25	25	27	28	29	31	31	32	33	34	35	37	39	41	43	46
	Coal	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3
50%	Solar	3	8	12	17	21	26	30	35	39	44	44	44	44	44	44	44	44	44	44	44	44
	Wind	2	3	5	7	9	11	13	15	17	19	21	23	25	27	28	28	28	28	28	28	28
	Hydro	8	8	8	8	9	9	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
	CCGT	20	21	22	24	24	25	25	27	28	29	31	31	32	33	33	35	37	39	41	43	45

L_{VRE}	Type	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	Coal	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3
60%	Solar	3	8	12	17	21	26	30	35	39	44	48	52	53	54	55	55	55	55	55	55	55
	Wind	2	3	5	7	9	11	13	15	17	19	21	23	25	27	29	31	33	34	36	36	36
	Hydro	8	8	8	8	9	9	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
	CCGT	20	21	22	24	24	25	25	27	28	29	31	31	32	33	33	35	37	39	41	43	45
	Coal	5	5	5	5	5	5	5	5	5	5	4	4	4	4	4	3	3	3	3	3	3

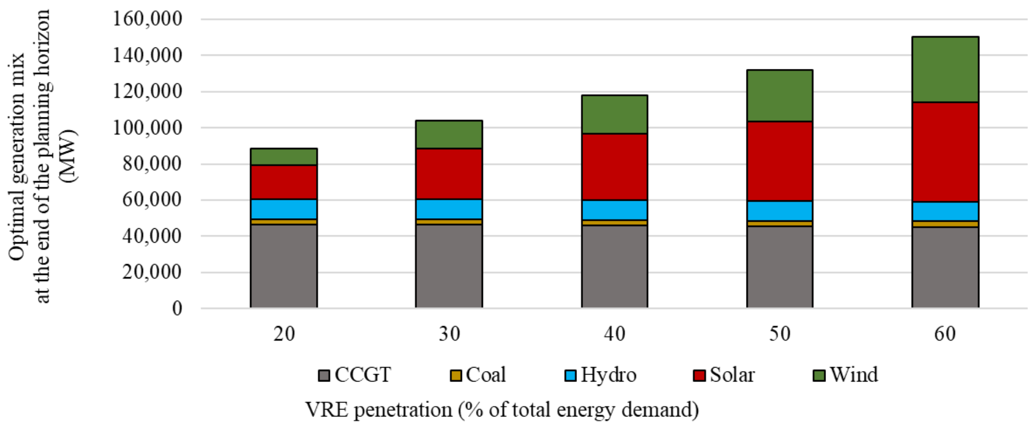


Figure 53 The optimal generation mix at a specific level of VRE penetration (at the end of the planning horizon).

Total system costs at a specific VRE penetration level were minimized by the method shown in Section 5.1.1. Figure 54 shows the electricity generation proportion at the end of the planning horizon. Note that the energy from VRE shown in the graph is the total amount of energy after the curtailment. The results show that the energy generated by conventional generators was decreased by VRE penetration, and the energy from CCGTs was reduced the most.

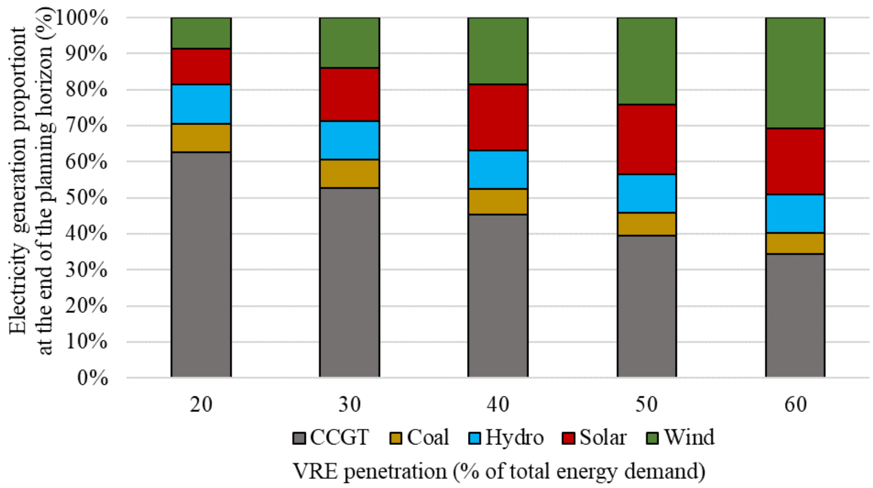


Figure 54 Electricity generation proportion at the end of the planning horizon.

The relations between total system costs and VRE penetration throughout the plan are shown in Figure 55. Overall, total system costs are decreased because VRE reduces the system's variable costs (VCs) by saving fossil fuel costs. However, at 40-60% VRE penetration, the total system costs are almost the same. That is because the avoided VCs are lower than the CCs of conventional and VRE generators combined, and VRE is curtailed to maintain SOCs. The direct integration cost, i.e., flexibility costs (FCs), does not affect the total system costs and is hardly changed by VRE penetration.

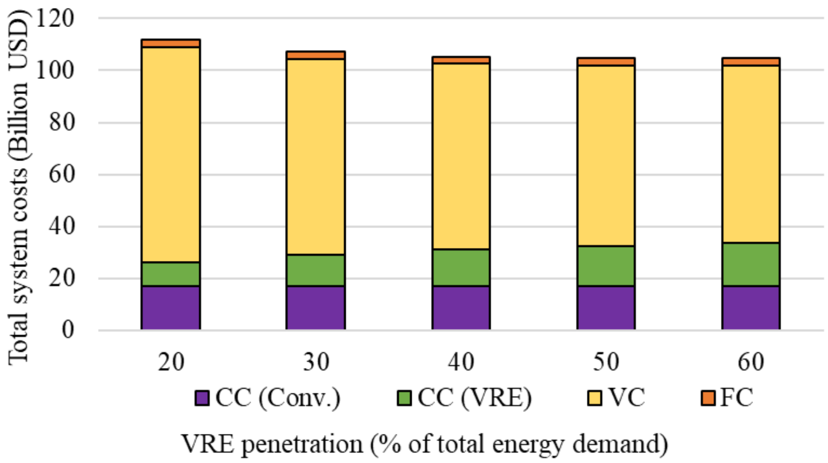


Figure 55 Relations between total system costs and VRE penetration throughout the plan.

7.1.2 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 5.1.1. These results were further analyzed together with performing the energy market simulation to determine the electricity generation revenue from energy markets and the indirect integration costs,i.e., the utilization costs from the reduction in supplied energy (UC_E) and the utilization costs from the reduction in MPs (UC_{MP}). The capacity market simulation was performed to evaluate the electricity generation revenue from the market, as mentioned in Section 5.1.2.

7.1.2.1 Utilization costs from the reduction in supplied energy *(UC_E).*

UC_E of conventional generator is relevant to the capacity factor (CF), whereas UC_E 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. Figure 56 and Figure 57 show 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 utilization of the generators, are the causes of UC_E as shown in Figure 58.

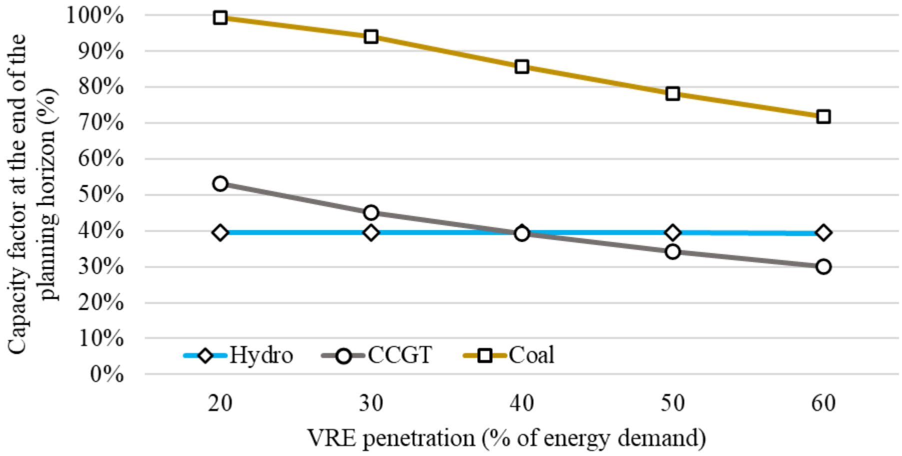


Figure 56 The capacity factor of conventional generators.

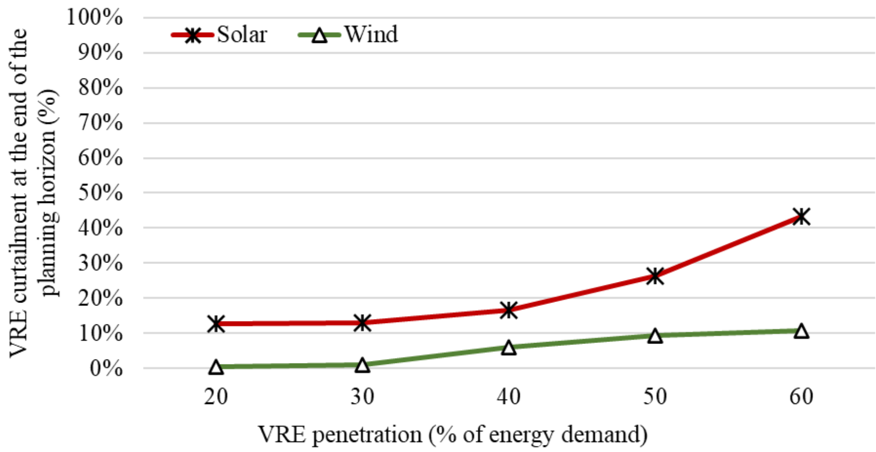


Figure 57 The curtailment of VRE generators.

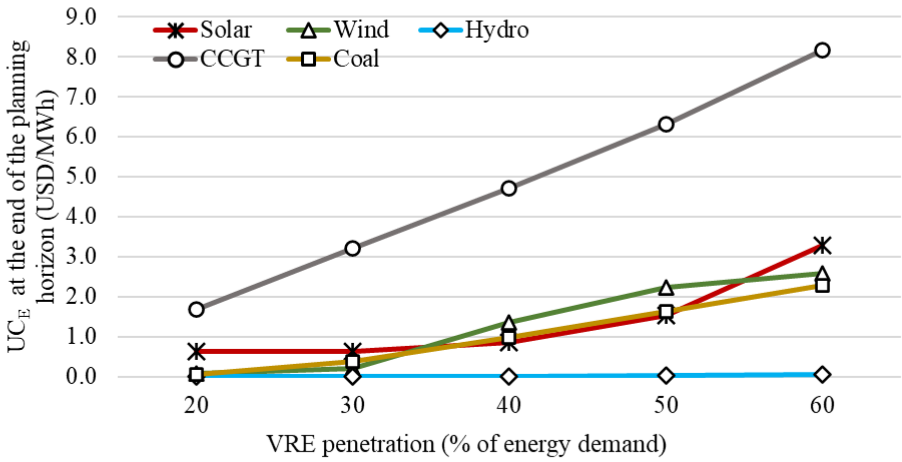


Figure 58 The UC_E incurred on generators.

The results show that the CF of the flexibility generators, i.e., CCGTs, is decreased by VRE penetration because the CCGT generators' installed capacity is necessary to satisfy SOCs. Still, 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, UC_E^{CCGT} and UC_E^{Coal} are increased in the same manner. For hydro generators, the CF of hydro generators is not dependent on VRE penetration because the generation is low price and flexible, so they are always committed to fully supplying energy. For VRE generators, the curtailment increase by VRE penetration. Otherwise, electricity generation and demand would be unbalanced. Solar curtailment occurs in all VRE penetration levels because the output from the generators exceeds electricity demand during the daytime. Wind generation curtailment starts at 30–60% VRE penetration. Installation of solar generators is much higher than wind. Solar generators' output is intense during the daytime, which could reach the limitation of the conventional generators to maintain SOCs. Thus, solar generation is more likely to be curtailed than wind generation. UC_E^{Solar} and UC_E^{Wind} are increased in relation to increased curtailment. Moreover, UC_E^{Solar} is lower than UC_E^{Wind} , even though wind generation is less curtailed than solar. This is because the wind installation cost is higher than that of solar, contributing to the higher UC_E. This reason can be applied to UC_E^{CCGT} and UC_E^{Coal} as well.

The impacts of VRE integration depend on not only VRE penetration, but also the load profile and the generation mix each year. Thus, it is essential to look into the impact of VRE each year where the electricity demand and the optimal generation mix are different. Figure 59 shows the annual capacity factor of conventional generators at 60% VRE penetration. Figure 60 shows the annual curtailment of VRE generators at 60% VRE penetration. Figure 61 shows the annual UC_E incurred on generators at 60% VRE penetration.

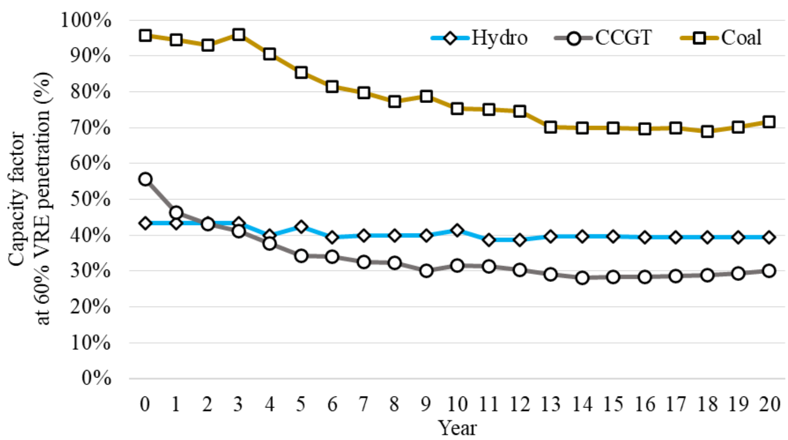


Figure 59 The annual capacity factor of conventional generators at 60% VRE penetration.

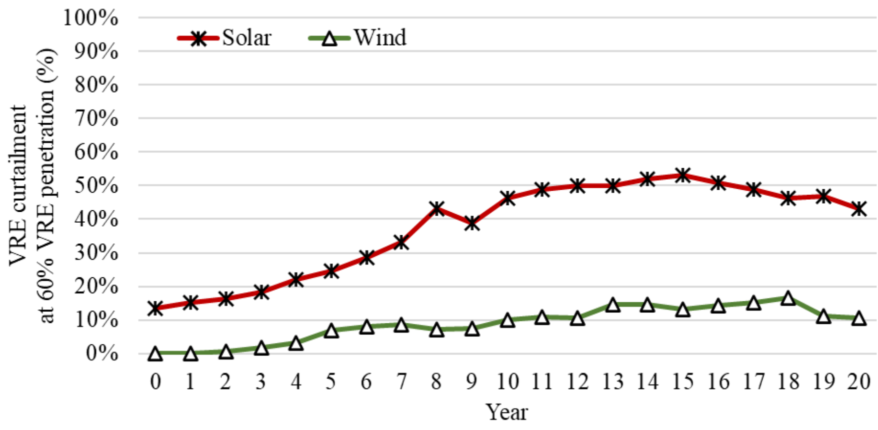


Figure 60 The annual curtailment of VRE generators at 60% VRE penetration.

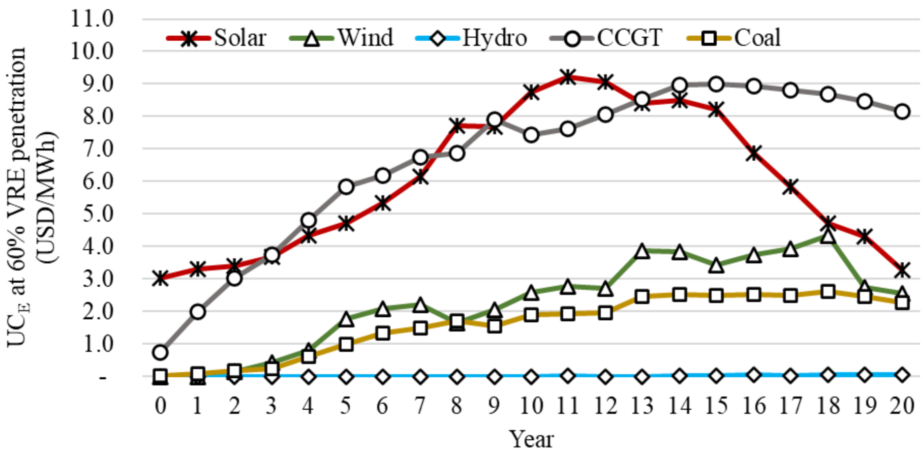


Figure 61 The annual UC_E incurred on generators at 60% VRE penetration.

7.1.2.2 Utilization costs from the reduction in MPs (UC_{MP}).

The MP of every considered period was evaluated to determine the utilization costs from the reduction in MP (UC_{MP}). Figure 69 to Figure 68 shows the UC_{MP} related to representative days and show relations between UC_{MP} and VRE penetration. The costs were calculated from the difference between the MPs with and without VRE integration at a specific time. The UC_{MP} is high on the day with low electricity demand, i.e., holidays or in winter, and when high VRE is integrated into the system, which is mid of the planning horizon.

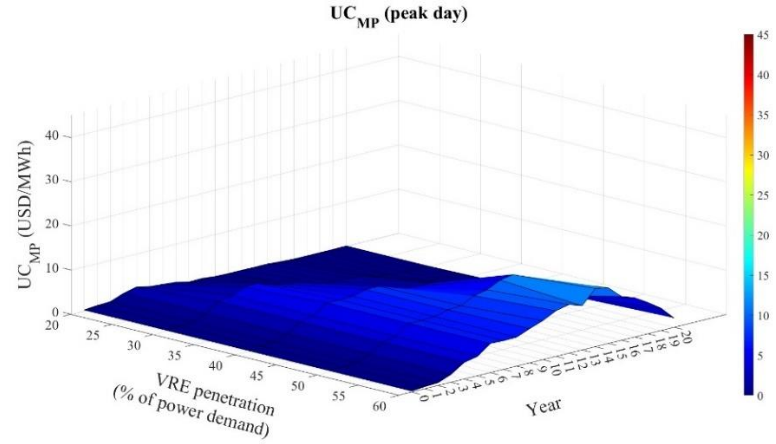


Figure 62 UC_{MP} considering the reduction of MPs on a peak day at a specific VRE penetration level.

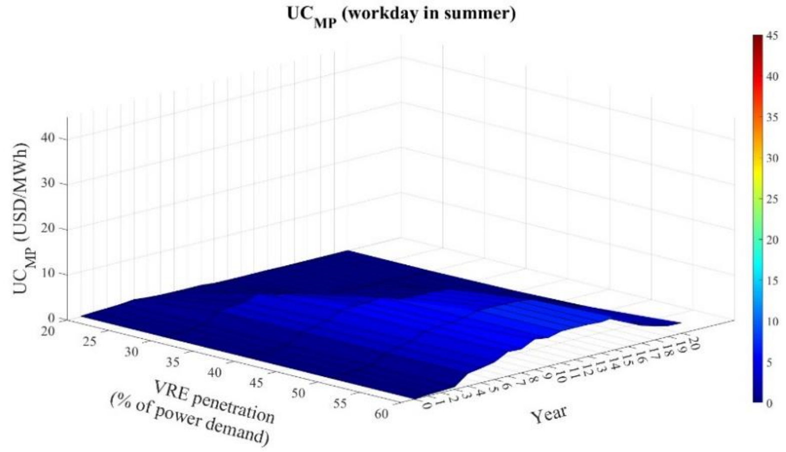


Figure 63 UC_{MP} considering the reduction of MPs on a workday in summer at a specific VRE penetration level.

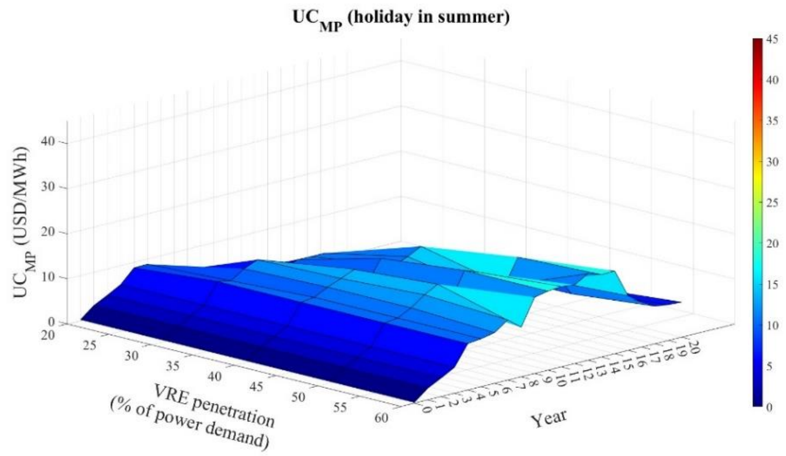


Figure 64 UC_{MP} considering the reduction of MPs on a holiday in summer at a specific VRE penetration level.

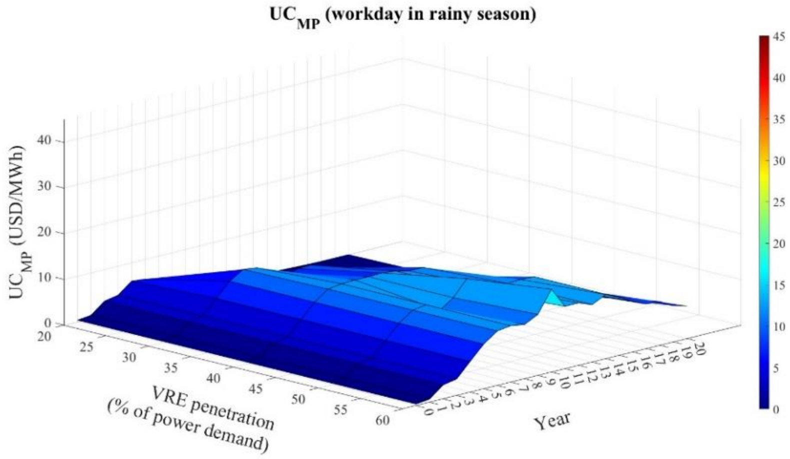


Figure 65 *UC_{MP}* considering the reduction of MPs on a workday in rainy at a specific VRE penetration level.

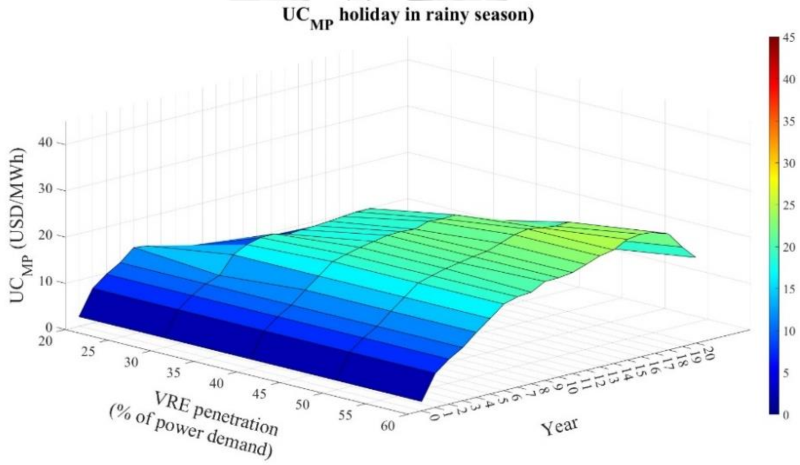


Figure 66 *UC_{MP}* considering the reduction of MPs on a holiday in rainy season at a specific VRE penetration level.

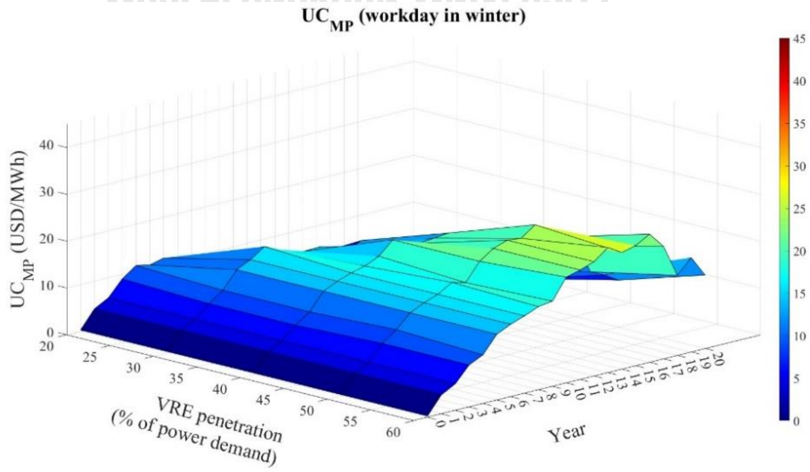


Figure 67 *UC_{MP}* considering the reduction of MPs on a workday in winter at a specific VRE penetration level.

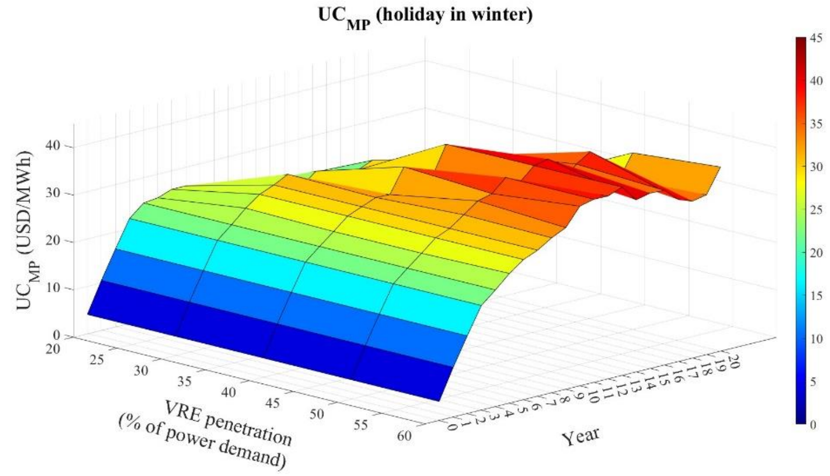


Figure 68 *UC$_{MP}$* considering the reduction of MPs on a holiday in winter at a specific VRE penetration level.

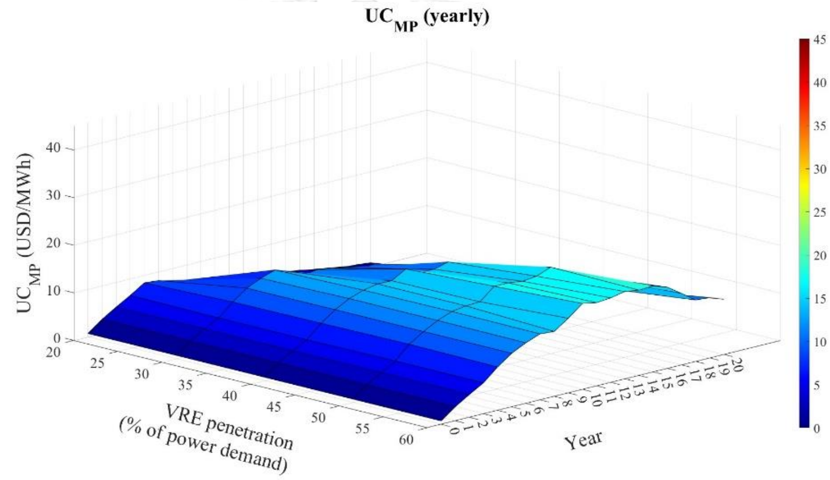


Figure 69 *UC$_{MP}$* considering the reduction of MPs throughout the year at a specific VRE penetration level.

From Figure 69 the *UC$_{MP}$* is the highest in the 13th year and at 60% VRE penetration. Figure 70 shows the MPs throughout the representative days, i.e., a peak day (Peak), a workday in summer (WS), a holiday in summer (HS), a workday in the rainy season (WR), a holiday in the rainy season (HR), a workday in winter (WW), and a holiday in winter (HW). The results show that MPs significantly decrease during daytime when the electricity generation from VRE is intense. That is because solar generators flood their low-price energy into the market at the time. The falls in MPs during the daytime, for example, at the 8 to 10th hour, are occurred because of the change in the marginal unit from CCGT generators to hydro generators. The huge difference between the marginal costs of the hydro and CCGT generators creates falls and spikes in the system's marginal prices.

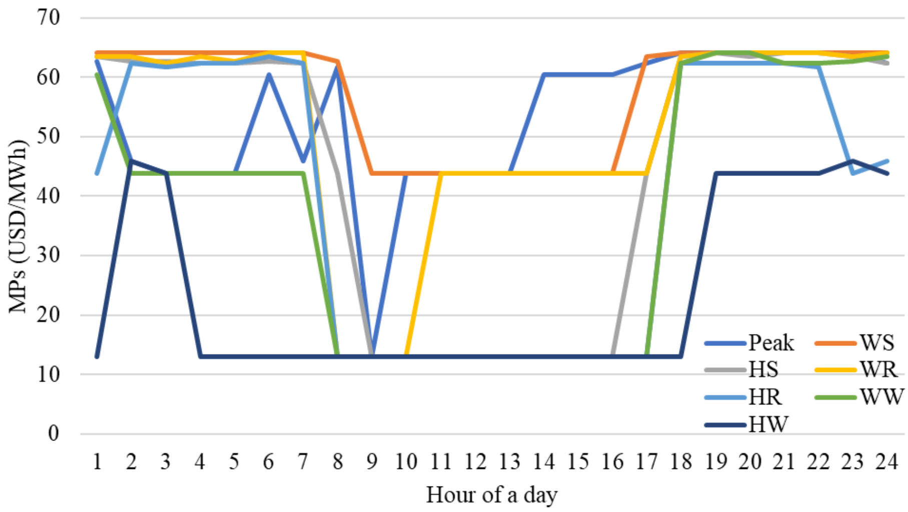


Figure 70 MPs throughout representative days at 60% VRE penetration level in the year 13th.

The costs from utilization effects, which are indirect integration costs, affect electricity generation revenue. Figure 71 shows the costs of generators compared with the revenue they gain from the energy electricity market. The figure considers the 13th year of the planning horizon, in which the impacts of VRE are most significant. If the average revenue (USD/MWh) is higher than the costs of generating electricity (USD/MWh), electricity generation is profitable. For all generators, their costs consisting of CCs, VCs, and FCs. UC_E are considered as increasing in specific capital costs. UC_{MP} show their effects through the reduction in prices. From Figure 71, CCGT generators cannot recover their costs by the revenue they gain even when there is no VRE penetration. If VRE is integrated, indirect integration costs would cause them worse unprofitable. CCGT 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 30% of total energy demand. There is profitable for hydro generators no matter VRE penetration because hydro is a low-cost and flexible resource, so they are always fully committed. Solar and wind generators are profitable at every VRE penetration level. However, the profit of all generators decreases by VRE penetration. UC_E^{CCGT} and UC_E^{Solar} are high compared to UC_E occur on other generators.

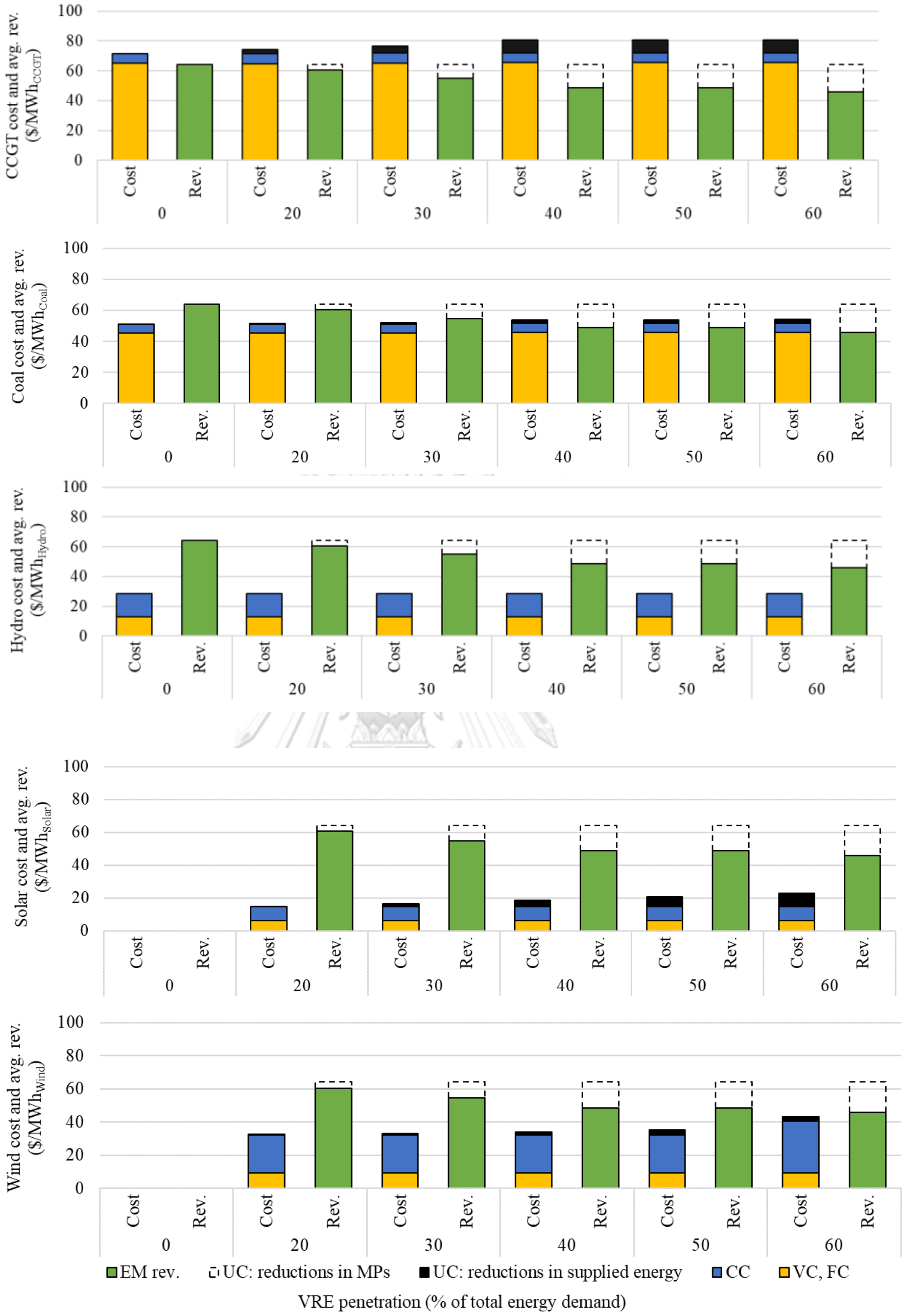


Figure 71 The costs of generation technology compared with the average revenue it gains from the energy market in the 13th year of the planning horizon.

The electricity generation revenue from the capacity market is evaluated by the method presented in Section 5.1.2.3. The capacity market revenue generators gain from the capacity market each year at a specific VRE penetration are shown in Table 30 to Table 28. All costs and revenue of one MW installation are shown in Figure 72.

Table 23 The capacity market revenue that generators gain from the capacity market each year at 0% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	-	-	468	1,264	243
1	-	-	468	1,264	243
2	-	-	468	1,264	243
3	-	-	468	1,264	243
4	-	-	468	1,264	243
5	-	-	497	1,579	256
6	-	-	497	1,579	256
7	-	-	497	1,579	256
8	-	-	497	1,579	256
9	-	-	497	1,579	256
10	-	-	556	1,823	190
11	-	-	556	1,823	190
12	-	-	556	1,823	190
13	-	-	556	1,823	190
14	-	-	556	1,823	190
15	-	-	556	2,437	158
16	-	-	556	2,437	158
17	-	-	556	2,437	158
18	-	-	556	2,437	158
19	-	-	556	2,437	158
20	-	-	556	2,437	158

Table 24 The capacity market revenue that generators gain from the capacity market each year at 20% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	43	15	468	1,178	243
1	59	23	468	1,178	243
2	22	28	468	1,178	243
3	17	36	468	1,178	243
4	10	44	468	1,178	243
5	10	44	497	1,498	256
6	10	44	497	1,498	256
7	10	44	497	1,498	256
8	20	46	497	1,498	256
9	20	46	497	1,498	256
10	20	46	556	1,742	190
11	20	46	556	1,742	190
12	20	46	556	1,742	190
13	20	46	556	1,742	190
14	34	48	556	1,742	190
15	34	48	556	2,354	158
16	34	48	556	2,354	158

Year	PV	Wind	Hydro	CCGT	Coal
17	34	48	556	2,354	158
18	34	48	556	2,354	158
19	34	48	556	2,354	158
20	34	48	556	2,354	158

Table 25 The capacity market revenue that generators gain from the capacity market each year at 30% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	43	15	468	1,208	243
1	59	23	468	1,208	243
2	22	28	468	1,208	243
3	17	36	468	1,208	243
4	11	42	468	1,208	243
5	13	49	497	1,493	256
6	15	55	497	1,493	256
7	15	63	497	1,493	256
8	15	63	497	1,493	256
9	15	63	497	1,493	256
10	15	66	556	1,736	190
11	15	66	556	1,736	190
12	15	66	556	1,736	190
13	15	69	556	1,736	190
14	15	69	556	1,736	190
15	15	69	556	2,351	158
16	15	69	556	2,351	158
17	15	69	556	2,351	158
18	15	72	556	2,351	158
19	15	72	556	2,351	158
20	15	72	556	2,351	158

Table 26 The capacity market revenue that generators gain from the capacity market each year at 40% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	43	15	468	1,209	243
1	59	23	468	1,209	243
2	22	28	468	1,209	243
3	17	36	468	1,209	243
4	11	42	468	1,209	243
5	13	49	497	1,477	256
6	15	55	497	1,477	256
7	18	60	497	1,477	256
8	19	65	497	1,477	256
9	19	72	497	1,477	256

Year	PV	Wind	Hydro	CCGT	Coal
10	19	79	556	1,712	190
11	19	79	556	1,712	190
12	19	79	556	1,712	190
13	19	83	556	1,712	190
14	19	83	556	1,712	190
15	19	83	556	2,326	158
16	19	83	556	2,326	158
17	19	87	556	2,326	158
18	19	87	556	2,326	158
19	19	87	556	2,326	158
20	19	91	556	2,326	158

Table 27 The capacity market revenue that generators gain from the capacity market each year at 50% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	43	15	468	1,216	243
1	59	23	468	1,216	243
2	22	28	468	1,216	243
3	17	36	468	1,216	243
4	11	42	468	1,216	243
5	13	49	497	1,485	256
6	15	55	497	1,485	256
7	18	60	497	1,485	256
8	20	61	497	1,485	256
9	22	65	497	1,485	256
10	23	71	556	1,691	190
11	23	78	556	1,691	190
12	23	84	556	1,691	190
13	23	91	556	1,691	190
14	23	97	556	1,691	190
15	23	97	556	2,305	158
16	23	102	556	2,305	158
17	23	102	556	2,305	158
18	23	108	556	2,305	158
19	23	108	556	2,305	158
20	23	108	556	2,305	158

Table 28 The capacity market revenue that generators gain from the capacity market each year at 50% VRE penetration (Million USD).

Year	PV	Wind	Hydro	CCGT	Coal
0	43	15	468	1,221	243
1	59	23	468	1,221	243
2	22	28	468	1,221	243

Year	PV	Wind	Hydro	CCGT	Coal
3	17	36	468	1,221	243
4	11	42	468	1,221	243
5	13	49	497	1,498	256
6	15	55	497	1,498	256
7	18	60	497	1,498	256
8	20	61	497	1,498	256
9	22	65	497	1,498	256
10	25	67	556	1,701	190
11	27	73	556	1,701	190
12	27	75	556	1,701	190
13	28	81	556	1,701	190
14	28	87	556	1,701	190
15	28	92	556	2,291	158
16	28	98	556	2,291	158
17	28	104	556	2,291	158
18	28	117	556	2,291	158
19	28	117	556	2,291	158
20	28	117	556	2,291	158

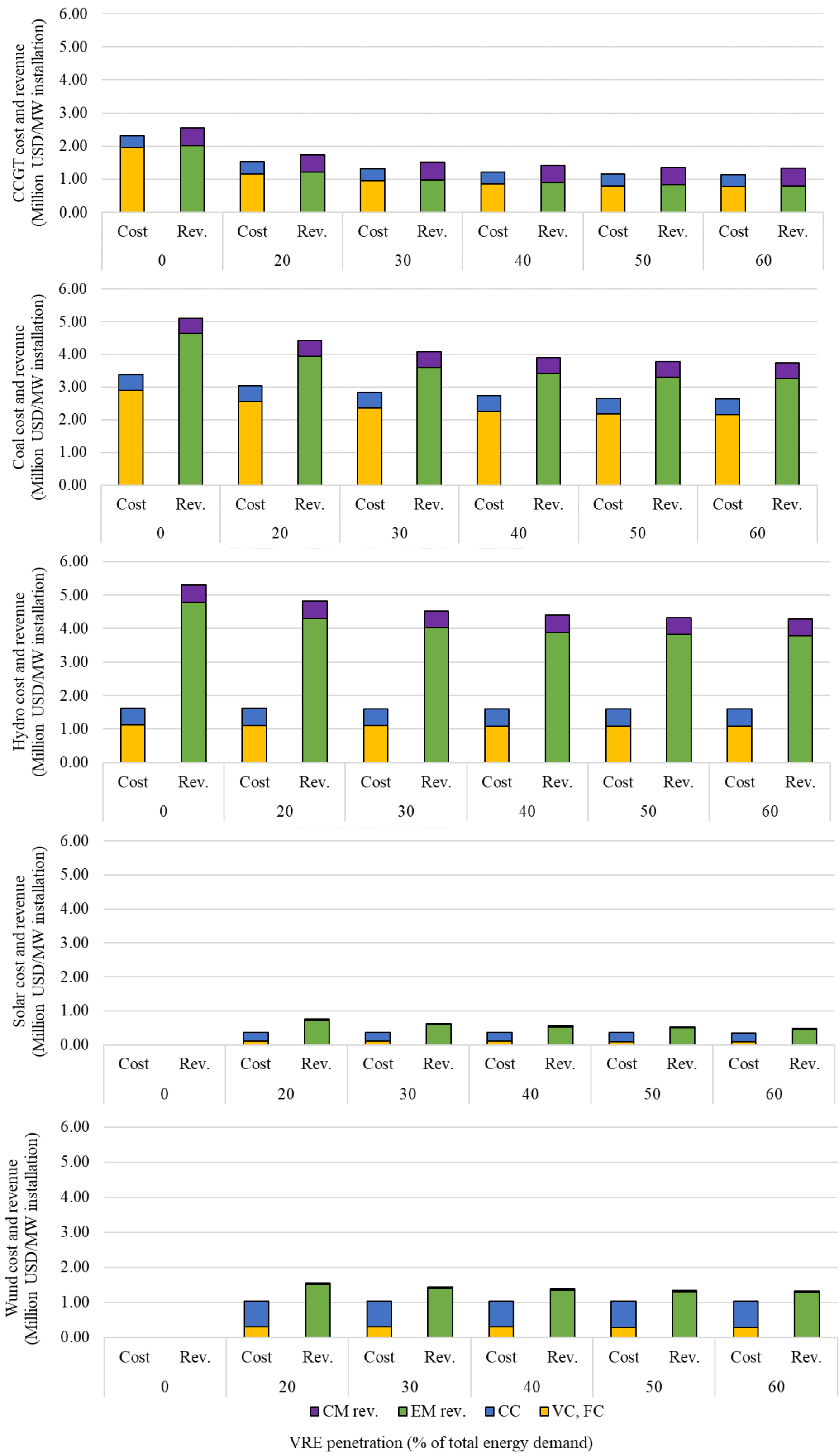


Figure 72 All costs and revenue of one MW installation.

VRE generators can not gain as much revenue from the capacity market as conventional generators because the capacity credits are too low. However, revenue from the energy market alone can make VRE generators profitable. To be profitable, conventional generators must gain revenue from both the energy and capacity markets. Hydro generators make high profits from both markets because of their low VCs and high FCAP. However, hydro has limitations in construction. Profit of all generators decreases by VRE penetration because of MOE in the energy market. The capacity market revenue is stable regardless of VRE penetration because CCGTs always set the clearing prices.

All the results show that integrating a high share of VRE into the system causes high total system costs and inefficient utilization of generators, especially thermal generators. Moreover, VRE penetration decreases the average revenue generators gain from the energy market. These contribute to indirect integration costs. The indirect integration costs' consequences can in turn increase electricity prices and discourage generators' investment. Electrical system planners and policymakers must consider these consequences to determine VRE-relevant plans and policies. If the generators cannot recover their costs through energy markets and capacity mechanisms, additional subsidies are needed to boost investment attractiveness. Figure 71 shows the cost-value of generated. Figure 72 shows the profitability of investing one MW of generation technology. Plans and policies should prioritize the severity of indirect integration costs on each technology grown with VRE penetration taking the information provided by both figures. For example, suppose system planners and policymakers need to increase VRE penetration to 60% of total energy demand. Figure 71 shows that, in the 13th year, VRE and hydro generators are not expected to encounter significant impacts from indirect integration costs. Support schemes for VRE and hydro generators might not be essentially required at the time. The policymakers must consider schemes that will remediate the severe indirect integration costs incurred to CCGTs and coal generators at the time. However, too much attractiveness boosting may sustain unnecessary generation technologies and slow the procurement of new technologies that are fully compatible with VRE, ultimately delaying the energy transition and raising costs. Customers eventually pay the cost of support schemes; thus, it should be minimized. The schemes might not need to compensate all indirect integration costs to the generators. The value of 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 the generators' worth [114]. In addition, it is essential to note that conventional generators would find their added value from capacity mechanisms for providing system PRM, as shown in Figure 72. However, the planner should realize that the PRM could be provided from various technologies other than conventional generators. Redundant in conventional generator investment may severely affect the generator by VRE penetration. In contrast, 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.

7.2 The impacts of VRE integration on total system costs and electricity generation revenue after mitigation

The VRE impacts mitigation methodology in Section 5.2 was performed to determine the impacts of VRE integration on total system costs and electricity generation revenue after mitigation. The effect of VRE impacts mitigation by enhancing system flexibility and the effect of VRE impacts mitigation by using a bidding strategy are shown in Sections 7.2.1 and 7.2.1, respectively.

7.2.1 Effect of VRE impacts mitigation by enhancing system flexibility

From all the results shown in Section 7.1, this section shows how enhancing system flexibility mitigates the impacts of VRE integration on electricity generation revenue by reducing the total system costs and UC_E. For total system costs, enhancing system flexibility reduces VCs and FCs by 3.38 Billion USD and 0.10 Billion USD, respectively. The total system costs were decreased by 3.48 Billion USD. Figure 73 compares the total system costs before and after enhancing system flexibility. Figure 74 shows the comparison between the capacity factor of conventional generators before and after enhancing system flexibility. Figure 75 compares the VRE curtailment before and after enhancing system flexibility. Figure 76 compares the UC_E incurred on conventional generators before and after enhancing system flexibility. Figure 77 shows the comparison between the UC_E incurred on VRE generators before and after enhancing system flexibility.

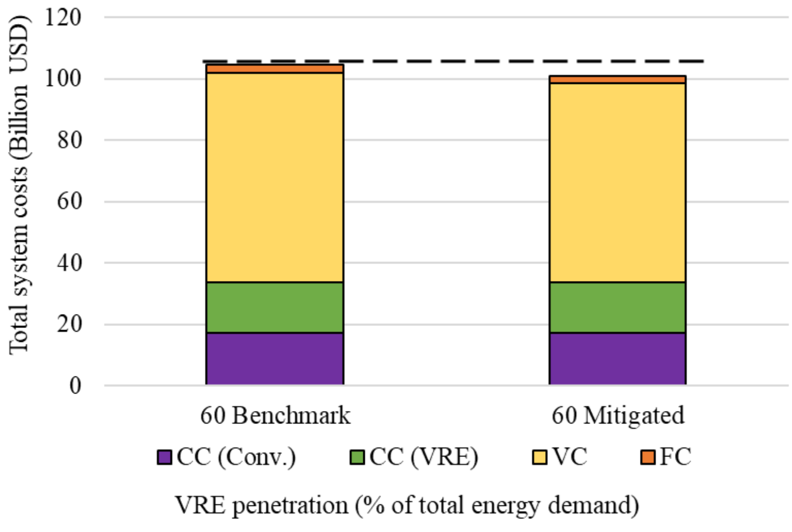


Figure 73 The comparison between the total system costs before and after enhancing system flexibility.

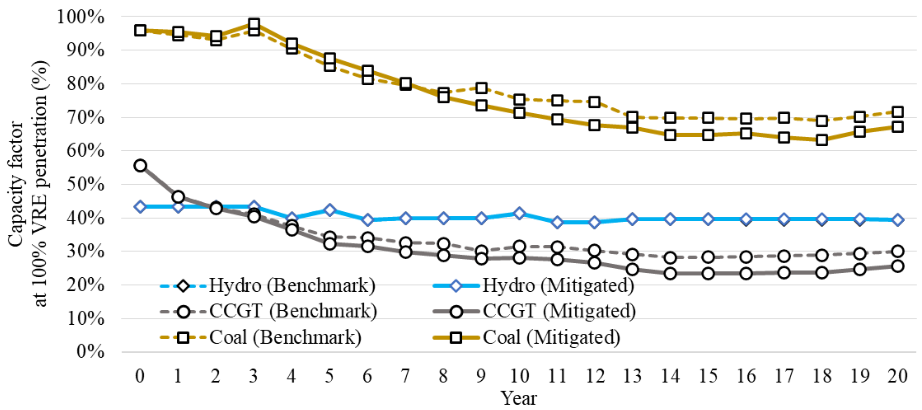


Figure 74 The comparison between the capacity factor of conventional generators before and after enhancing system flexibility.

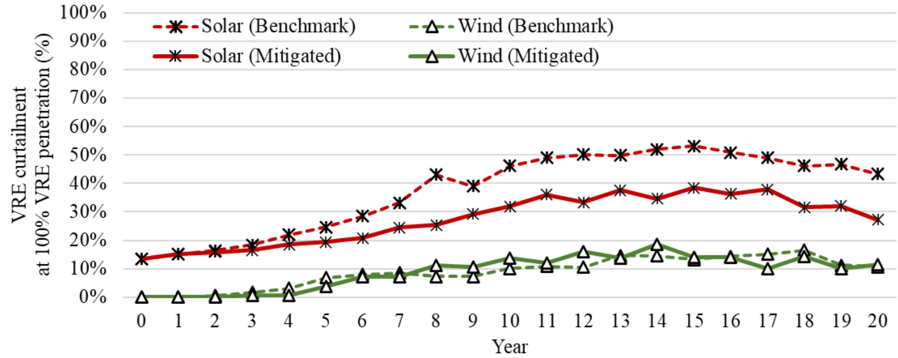


Figure 75 The comparison between the VRE curtailment before and after enhancing system flexibility.

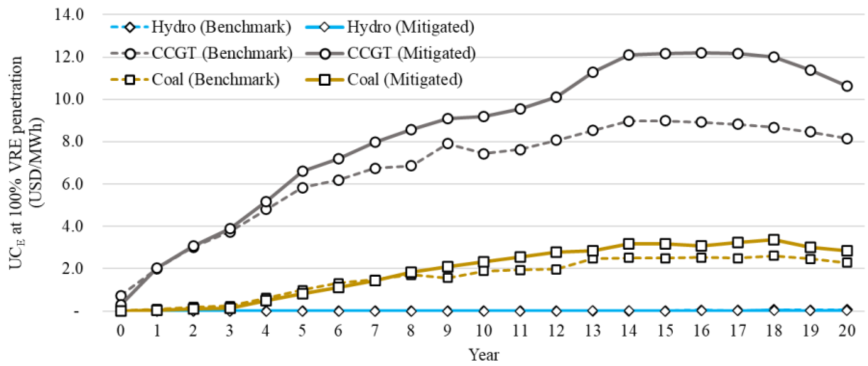


Figure 76 The comparison between the UC_E incurred on conventional generators before and after enhancing system flexibility.

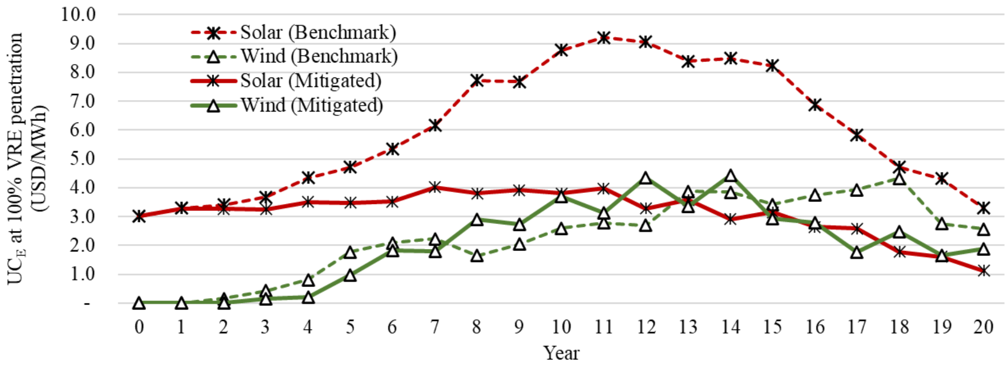


Figure 77 The comparison between the UC_E incurred on VRE generators before and after enhancing system flexibility.

The cost of retrofitting a thermal generator is around 12.75 USD/kW [115], while the existing thermal generator in the system in 2022 is 27,548 MW [2]. Table 29 shows the cost-benefit of enhancing system flexibility.

Table 29 The cost-benefit of enhancing system flexibility.

Avoided costs	3.48	Billion USD
Retrofit costs per kW	112.75	USD/kW
Existing thermal plant	27,548.00	MW
Total retrofit costs	3.11	Billion USD
Profit retrofit	**0.37**	Billion USD

7.2.2 Effect of VRE impacts mitigation by using a bidding strategy

The method in Section 5.2 was applied to the test system to find the optimal VRE generation schedules that maximized VRE power plants' profits while considering MPs and system reliability. The traditional method (Benchmark case) is also illustrated to compare the results. The optimal daily operation schedules of VRE generators on seven representative days are obtained. The method adjusts the types of VRE support schemes since the support schemes are an essential factor for setting offer prices. The VRE power plants' daily profits and the VRE outputs from both methods are shown in Table 30. In the table, the comparisons of the profit and output are presented in the "difference" columns.

Table 30 The VRE power plants' daily profits (MUSD) and the output (GWh).

Day	VRE Support Scheme Scenarios	Wind						Solar					
		Bidding strategy		Benchmark		Difference		Bidding strategy		Benchmark		Difference	
		Profit	Output	Profit	Output	Profit	Output	Profit	Output	Profit	Output	Profit	Output
Peak	None	6.02	138.23	6.02	138.23	0.00	0.00	8.96	208.61	8.96	208.61	0.00	0.00
	FIP	14.93	138.23	14.93	138.23	0.00	0.00	32.83	208.61	32.83	208.61	0.00	0.00
	FIT	11.81	138.23	11.81	138.23	0.00	0.00	25.33	208.61	25.33	208.61	0.00	0.00
WS	None	8.16	160.54	8.16	160.54	0.00	0.00	7.80	197.21	7.80	197.21	0.00	0.00
	FIP	18.51	160.54	18.51	160.54	0.00	0.00	30.36	197.21	30.36	197.21	0.00	0.00

Day	VRE Support Scheme Scenarios	Wind						Solar					
		Bidding strategy		Benchmark		Difference		Bidding strategy		Benchmark		Difference	
		Profit	Output	Profit	Output	Profit	Output	Profit	Output	Profit	Output	Profit	Output
	FIT	13.72	160.54	13.72	160.54	0.00	0.00	23.95	197.21	23.95	197.21	0.00	0.00
HS	None	6.93	159.64	6.93	159.64	0.00	0.00	3.27	60.82	1.71	154.54	1.56	(93.71)
	FIP	17.23	159.64	17.23	159.64	0.00	0.00	19.39	154.54	19.39	154.54	0.00	0.00
	FIT	13.64	159.64	13.64	159.64	0.00	0.00	18.77	154.54	18.77	154.54	0.00	0.00
WR	None	7.87	158.86	7.87	158.86	0.00	0.00	6.33	212.90	6.33	212.90	0.00	0.00
	FIP	18.11	158.86	18.11	158.86	0.00	0.00	30.68	212.90	30.68	212.90	0.00	0.00
	FIT	13.57	158.86	13.57	158.86	0.00	0.00	25.85	212.90	25.85	212.90	0.00	0.00
HR	None	6.49	170.29	6.49	170.29	0.00	0.00	3.26	82.86	1.45	153.00	1.81	(70.14)
	FIP	17.47	170.29	17.47	170.29	0.00	0.00	18.96	153.00	18.96	153.00	0.00	0.00
	FIT	14.55	170.29	14.55	170.29	0.00	0.00	18.58	153.00	18.58	153.00	0.00	0.00
WW	None	8.69	318.30	8.69	318.30	0.00	0.00	0.97	103.86	0.97	103.86	0.00	0.00
	FIP	29.21	318.30	29.21	318.30	0.00	0.00	12.85	103.86	12.85	103.86	0.00	0.00
	FIT	27.19	318.30	27.19	318.30	0.00	0.00	12.61	103.86	12.61	103.86	0.00	0.00
HW	None	2.68	228.18	2.68	228.18	0.00	0.00	0.31	45.52	0.31	45.52	0.00	0.00
	FIP	17.39	228.18	17.39	228.18	0.00	0.00	5.52	45.52	5.52	45.52	0.00	0.00
	FIT	19.49	228.18	19.49	228.18	0.00	0.00	5.53	45.52	5.53	45.52	0.00	0.00

From Table 30, the overview of the results shows that the generators' profits depend on the quantity of output and the revenue they gain from the MPs and support schemes. FIP-supported generators made the most profits in most scenarios because they received revenue from MPs and support schemes. However, both FIP and FIT-supported generators made considerably greater profits than the generators without support.

To illustrate the benefit of the bidding strategy method, the "difference" columns in Table 30 show the differences between profit and output from the bidding strategy method and the traditional method. If there is no difference (0.00), it means the results from the bidding strategy method and the traditional method were the same; maximizing the VRE output is still the method that provides the maximized profit in that situation. The results show that the VRE output of the bidding strategy method was diverse, depending on the support schemes that involve MPs and revenue. The VRE output of the traditional method was the same regardless of the support schemes because the method maximized VRE output in any case.

Moreover, the results prove that VRE generators' profits from the bidding strategy method were higher than from the traditional method in the cases of the system having moderate electricity demands—i.e., cases HS and HR. For example, in case of HS, the profits from the bidding strategy method were higher than for the traditional method by 1.56 MUSD, though the solar output from the bidding strategy method was less than that from the traditional method by 93.71 GWh. That means selling less electricity to gain high MPs (the bidding strategy method) provided more profits than continually selling maximized electricity at low MPs (the traditional method). The reason is that in cases where the system has the moderate electricity demand, the marginal units in these situations tend can be switched from hydro generators to CCGTs. Hydro generators have low MCs, whereas CCGT generators have high MCs; thus, it is worth curtailing some VRE output to change the marginal unit to be CCGT power plants because the MPs will be significantly driven up. On the day that the electricity demand is high, the MPs are initially high. On the day that the electricity demand is low, the marginal unit is hydro generators and would not change to CCGTs by curtailing a reasonable amount of VRE. Thus, selling the maximum output of VRE as a traditional method provides maximum profit. Moreover, curtailing solar generation provides optimal physical withholding than curtailing wind generation because solar's VCs are lower than Wind's, and curtailing solar has the potential to drive MPs up in the daytime when demand is low.

Additionally, the bidding strategy method provided significantly more profits than the traditional method when VRE power plants received no support because MPs were the only factor involved in their profits. FIP and FIT-supported generators always maximize their outputs (same as the traditional method) because they gain a fixed price for every MWh they produce, and their profits are independent of the MPs.

The VRE optimal generation schedules and the MPs of every case are presented in Table 30. This dissertation presents cases where the bidding strategy method provided greater profits than the traditional method: case HS and HR, wherein VRE received no support. Figure 78 to Figure 81 shows the optimal VRE generation schedules and the MPs of those cases.

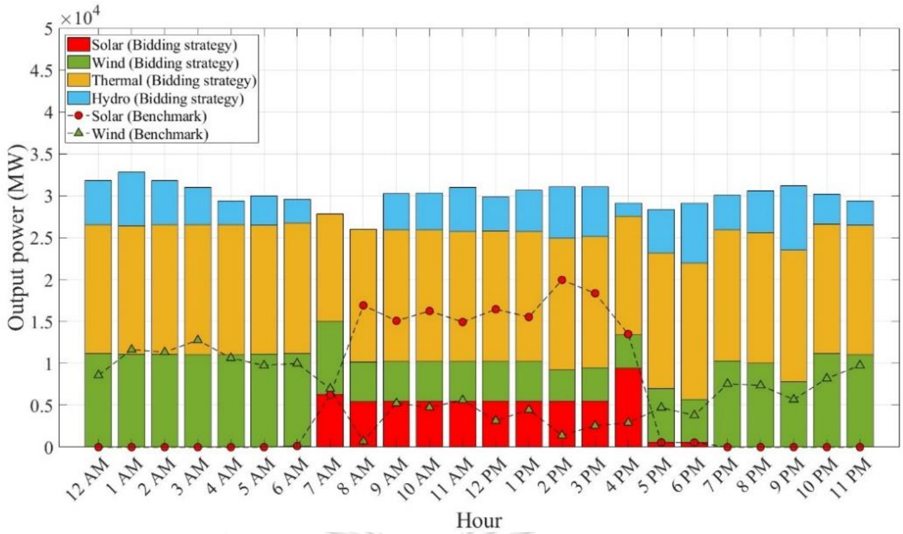


Figure 78 The optimal VRE generation schedule on holiday in summer, where VRE generators receive no support.

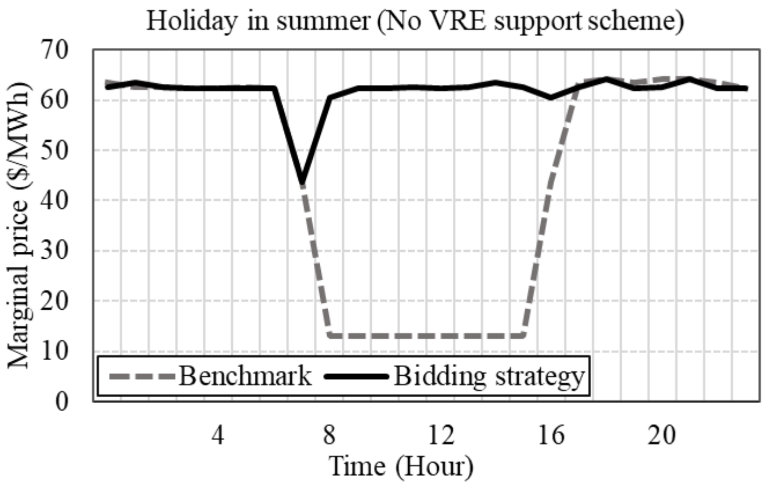


Figure 79 The MPs on holiday in summer, where VRE generators receive no support.

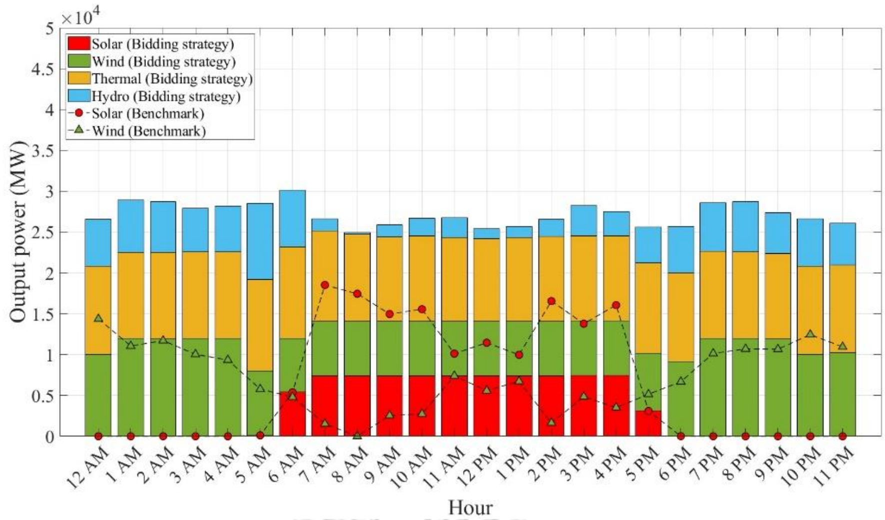


Figure 80 The optimal VRE generation schedule on holiday in rainy season, where VRE generators receive no support schemes.

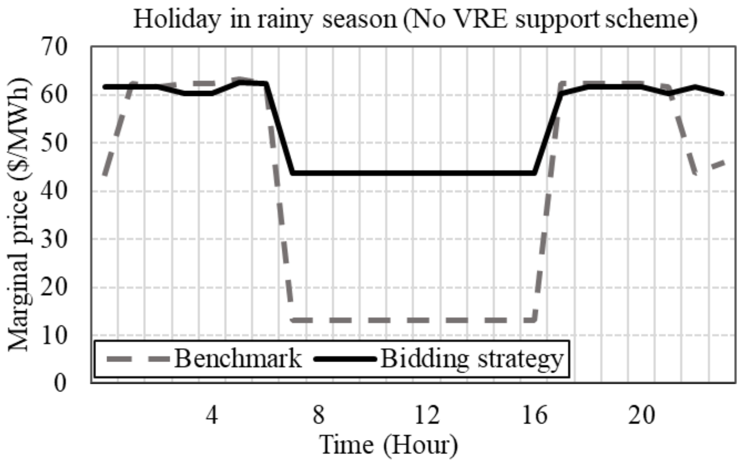


Figure 81 The MPs on holiday in rainy season, where VRE generators receive no support schemes.

Figure 78, and Figure 80 show that the solar and wind output from the bidding strategy method was lower than from the traditional method, contributing to a higher MPs, as shown in Figure 79, and Figure 81. The bidding strategy method could increase the MPs from the traditional method by 50.36 USD/MWh on holiday in summer, and by 30.73 USD/MWh on holiday in rainy season. The average MP during the day was driven up around 16.92 USD/MWh (37.78%), and 14.47 USD/MWh (36.61%), respectively. Table 31 shows the optimal solar output levels during a day in the unit of percent of the maximum output generators could provide.

Table 31 The optimal solar output level during a day: the scenario of HS and HR, where VRE generators receive no support (% of the generators' maximum output).

Time	HS (No support)		HR (No support)	
	Bidding strategy	Traditional	Bidding strategy	Traditional
12 a.m.	0%	0%	0%	0%
1 a.m.	0%	0%	0%	0%
2 a.m.	0%	0%	0%	0%
3 a.m.	0%	0%	0%	0%
4 a.m.	0%	0%	0%	0%
5 a.m.	99%	99%	100%	99%
6 a.m.	100%	99%	100%	99%
7 a.m.	100%	99%	40%	99%
8 a.m.	32%	99%	22%	51%
9 a.m.	17%	46%	20%	41%
10 a.m.	15%	46%	21%	44%
11 a.m.	14%	39%	25%	34%
12 p.m.	16%	48%	22%	34%
1 p.m.	15%	43%	24%	33%
2 p.m.	14%	50%	25%	55%
3 p.m.	14%	45%	21%	38%
4 p.m.	69%	99%	34%	73%
5 p.m.	100%	99%	100%	99%
6 p.m.	100%	99%	100%	99%
7 p.m.	0%	0%	0%	0%
8 p.m.	0%	0%	0%	0%
9 p.m.	0%	0%	0%	0%
10 p.m.	0%	0%	0%	0%
11 p.m.	0%	0%	0%	0%
Avg	21%	52%	26%	48%

VRE generators were not the marginal unit in all cases because the VRE penetration was insufficient to serve all the electricity demands. However, if the system's flexibility is improved and more VRE can be integrated, the MPs would be very low if VRE were to be the marginal unit. The MPs could be equal to the VRE MCs, if VRE power plants are not supported, or there could be negative support prices, if VRE power plants are supported. In these cases, the bidding strategy method will benefit more significantly than the traditional method. Moreover, VRE power plants can gain more revenue by using energy storage. The curtailed VRE output from the bidding strategy method can be stored and sold back to the system when electricity demand is high. However, the costs incurred from using energy storage, such as installation costs, and costs from lost energy due to the efficiency of the energy storage, must be less than the revenue to avoid negative profits.

Chapter 8

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 dissertation proposes a novel method to determine the impacts of VRE integration on total system costs and electricity generation revenue. The VRE impact mitigation methods and their outcome are also provided.

The results showed the optimal generation mix at the end of the planning horizon at a specific VRE penetration. VRE capital costs increased by VRE penetration, whereas those of the conventional generation were hardly changed by the VRE penetration level. This is because no matter how many VRE generators will be 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 guarantee the adequacy of PRM. However, the energy generated by conventional generators was decreased by VRE penetration, and the energy from CCGTs was reduced the most. Overall, total system costs are decreased because VRE reduces the system's variable costs by saving fossil fuel costs. However, at 40-60% VRE penetration, the total system costs are almost the same. That is because the avoided variable costs are lower than the capital costs of conventional and VRE generators combined, and VRE is curtailed to maintain SOCs. The direct integration cost, i.e., flexibility costs, does not affect the total system costs and is hardly changed by VRE penetration. The impacts of VRE integration not only depend on VRE penetration, but also the load profile and the generation mix in each year. CCGT generators cannot recover their costs by the average revenue they gain in energy market even when there is no VRE penetration. If VRE is integrated, indirect integration costs would cause them worse unprofitable. CCGT generators need to recover the remaining costs from capacity markets. Coal generators face fewer effects than CCGTs, and the generators are unprofitable if VRE is integrated by more than 30% of total energy demand. For hydro generators, they are profitable no matter VRE penetration because hydro are low-cost resource and flexible, so they are always fully committed. Solar and wind generators are profitable at every VRE penetration level. However, the profit of all generators is decreased with increasing VRE penetration. UC_E^{CCGT} and UC_E^{Solar} are high compared to UC_E of other generators even at low VRE penetration.

Integrating a high share of VRE into the system causes high total system costs and inefficient utilization of generators, especially thermal generators. Moreover, VRE penetration decreases the average revenue generators gain from the energy market. These contribute to indirect integration costs. The indirect integration costs' consequences can in turn increase electricity prices and discourage generators' investment. It is essential to note that conventional generators would find their added value from capacity mechanisms for providing system reserve margin, but the reserve margin could be provided from various technologies other than conventional generators. Electrical system planners and policymakers must consider these consequences to determine VRE-relevant plans and policies. If the generators are unable to recover their costs through energy markets and capacity mechanisms, then additional subsidies are needed to boost investment attractiveness.

Moreover, system planners and policymakers could consider several ways to mitigate the impact of VRE integration. Enhancing system flexibility slightly decreases total system cost of the system by reducing variable and flexibility costs. Flexibility resources can be used to provide system operation services rather than only relying on conventional generators [112]. Bidding strategies also help deal with energy market challenges [10, 23]. 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.

Electricity system planners and policymakers need to prioritize and consider the severity of the VRE impacts on total system costs and electricity generation revenue to enact plans and policies consistent with the impacts on customers and each type of power plant. In addition, the VRE impact mitigation should be done and promoted considering the necessity, costs, and benefits.

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