USAID VIETNAM LOW EMISSION ENERGY PROGRAM (V-LEEP)

Technical Report: Impact analysis of integrating significant renewable energy in Vietnam's power sector: A PLEXOS-based analysis of long-term power development planning

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Prepared by:

Deloitte.

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ABBREVIATIONS AND ACRONYMS

BAU	Business as Usual
CAPEX	Capital Expenditures for investment of new generation or transmission
CCGT	Combined Cycle Gas Turbine
CEM	Capacity Expansion Modeling or Capacity Expansion Model
CIFF	Children's Investment Fund Foundation
DEA	Danish Energy Agency
DOE	Department of Energy
DSM	Demand-Side Management
EE	Energy Efficiency
ERAV	Electricity Regulatory Authority of Vietnam
EREA	Electricity and Renewable Energy Authority
EUE	Expected Unserved Energy
EVN	Vietnam Electricity
GHG	Greenhouse Gas
GVN	Government of Vietnam
GW	Gigawatt
GWh	Gigawatt-hour
HNEI	Hawaii Natural Energy Institute
HVDC	High Voltage Direct Current
ICE	Internal combustion engine
IDC	Interest during Construction
IEVN	Institute of Energy of Vietnam
IRENA	International Renewable Energy Agency
kV	Kilovolts
LDC	Load Duration Curve
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LP	Linear Programming
LT	Long-term
MIP	Mixed Integer Programming

MOIT	Ministry of Industry and Trade
MSL	Minimum stable level or technical minimum
MT	Medium-term
MW	Megawatt
MWG	Modeling Working Group
NDC	Nationally Determined Commitments
NEUE	Normalized Expected Unserved Energy
NLDC	National Load Dispatch Center, under Electricity Vietnam (also EVN-NLDC)
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
ONR	U.S. Office of Naval Research
PASA	Projected Assessment for System Adequacy
PCM	Production Cost Modeling or Production Cost Model
PDP	Power Development Plan
PDP-7	Vietnam's seventh Power Development Plan
PDP-8	Vietnam's eighth Power Development Plan
PLF	Plant Load Factor
ppm	Parts per Million
PRAS	Probabilistic Resource Adequacy Suite
PSPP	Pumped Storage Power Plant
RE	Renewable Energy
RPDP-7	Revised PDP-7
SCGT	Simple Cycle Gas Turbine
Solar PV	Solar Photovoltaic
ST	Short-term
USAID	United States Agency for International Development
USE	Unserved Energy
U.S.	United States of America
V-LEEP	Vietnam Low Emission Energy Program
vRE	Variable Renewable Energy or Variable RE
WACC	Weighted Average Cost of Capital

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V-LEEP OVERVIEW

The United States Agency for International Development (USAID) Vietnam Low Emission Energy Program (V-LEEP) helps the Government of Vietnam (GVN) establish an effective policy, regulatory, and incentive environment for low-emission growth in the energy sector, while simultaneously attracting public-sector and private-sector investment in renewable energy (RE) development and energy efficiency (EE). V-LEEP promotes the development of critical building blocks to scale up clean energy, such as accessible smart incentives for clean energy and EE investments, enabling a competitive environment for RE generation, enhancing renewable power grid integration, and ensuring locational concentration of clean energy generation facilities.

Three components form V-LEEP's core activities:

Component 1: Low Emission Strategy Development for the Energy Sector

Task 1.1: Enhance GVN capacity to analyze and develop clean energy strategies, and evaluate emission mitigation options for decision-making. This Task covers the technical support to strengthen National Power Planning Capacity (mainly PDP-8) and a study on Rapid Resiliency Plan for System Operations and Critical Infrastructure Protection.

Component 2: Enhance Capacity and Improve Enabling Environment for Renewable Energy Development

Task 2.1: Enhance the capacity of Vietnamese government institutions to improve the enabling environment for RE development. This Task focuses on a collaboration with the Electricity Regulatory Authority of Vietnam (ERAV) to design and pilot a Direct Power Purchase Agreements (DPPA) mechanism in Vietnam, and support to the Ministry of Industry and Trade (MOIT) on a Rooftop Solar PV Promotion Program.

Task 2.2: Enhance the capacity of RE developers and the private sector in large-scale RE development, through providing customized one-on-one support to RE project developers.

Component 3: Increase Energy Efficiency Adoption and Compliance

Task 3.1: Enhance government capacity to strengthen energy efficiency policy implementation. The Task helps to improve compliance with Minimum Energy Performance Standards (MEPS) and develop Communications Strategy and Training Curriculum for the National Energy Efficiency Program 2021 – 2030 (VNEEP3).

Task 3.2: Enhance energy efficiency in energy-intensive industry sectors.

V-LEEP SUPPORT ON STRENGTHEN NATIONAL POWER PLANNING CAPACITY

Vietnam's eighth National Power Development Plan (PDP-8) will be the cornerstone ministerial-level plan that shapes the future of Vietnam's power sector. Under the 2015 Paris Agreement, Vietnam has committed to reducing its greenhouse gas (GHG) emissions; energy sector reductions are essential for meeting its associated Nationally Determined Contribution (NDC) commitment. As directed by the Prime Minister, MOIT is revisiting plans to build new coal-fired power plants and anticipates excluding plants with a high risk of environmental impact from the new PDP-8. With the costs of RE decreasing dramatically over the past few years and with the expectation of continued cost reduction in the future, the Electricity and Renewable Energy Authority (EREA) is targeting a higher percentage of RE in the national power mix. However, the successful integration of RE requires overcoming many technical and operational barriers.

MOIT's highest priority for V-LEEP is to enhance the capacity for using new tools and modeling approaches for the development of PDP-8. V-LEEP's role is complementary to the work of the PDP-8 implementing contractor – the Institute of Energy of Vietnam (IEVN). To provide support, V-LEEP successfully assembled a world-class team of power planning experts including the National Renewable Energy Laboratory (NREL); the Hawaii Natural Energy Institute (HNEI); and a V-LEEP cadre of local and international experts.

V-LEEP helped EREA build its capacity for adopting new approaches for developing and evaluating the new PDP-8 by assessing the implications of increased levels of variable RE in power dispatch and transmission planning. In 2018, V-LEEP provided detailed recommendations to EREA in a technical report, "Assessment and Recommendations on Methodology for Power Development Plan (PDP)."

Building on these recommendations, V-LEEP provided additional capacity-building support to a Modeling Working Group (MWG) consisting of EREA, IEVN, the Electricity Regulatory Authority of Vietnam (ERAV), and the National Load Dispatch Center (NLDC), on how to incorporate production cost modeling (PCM) into the long-term planning process in Vietnam (i.e., PDP-8 and the successive PDPs). V-LEEP procured a server that hosts a licensed PCM software tool – PLEXOS – and has transferred the server and license to EREA. V-LEEP provided training and model-development support to EREA and the core MWG to validate the available data and the use of PCM in the context of long-term power planning.

V-LEEP team worked on a PCM using PLEXOS to assess the Revised PDP-7 (RPDP-7) in the context of having higher RE sources in the power system. The technical report on the PCM was finalized and submitted to EREA in September 2020.

Based on the results of the above assessment and per the request of EREA, V-LEEP extended the Vietnam PLEXOS model with a long-term capacity expansion model (CEM) feature, which was combined with the short-term PCM analysis (or production cost analysis) for selected years. Results from the long-term CEM and the PCM analyses are expected to: 1) support the PDP-8 development, 2) assess the expansion plan from an operational perspective, 3) close the gap between the planning and operational phases, and 4) integrate power planning into future power market operations. Issues identified in the CEM and PCM analyses can be used as feedback for generation and transmission planning enabling planners to optimize the PDP-8 using the least-regret approach.

The V-LEEP team collaborated closely with NREL and HNEI, and was led by Dr. Ananth Chikkatur, with support from Ha Dang Son, Nguyen Trong Nghia, Le Thi Thu Ha, Nguyen Manh Cuong, Nguyen Van Duong, Pham Thu Tra My, Nguyen Hoang Lan, and Tran Thanh Son in Vietnam; and Shangmin Lin, Merril Stypula and Dr. Marija Prica in the U.S.

OUTLINE OF REPORT

This LT-Report summarizes the analysis of long-term capacity expansion scenarios and sensitivities that are modeled using the PLEXOS LT module, based on assumptions similar to those in the draft PDP-8 Version 3, which was published for public consultation in February 2021.[1] Please note that the scenario assumptions and modeling results in this report are not exactly the same as the draft PDP-8, although they are similar. In addition, PCM analysis for the Base Case scenario was conducted for 2023, 2025, and 2030. Reliability analysis was also done for these years using NREL's Probabilistic Resource Adequacy Suite (PRAS).

The next chapters (Chapters 1 and 2) summarize the report's key findings, recommendations, and suggested next steps. The rest of this report is organized as follows:

- Chapter 3 describes the background and context for this report.
- Chapter 4 provides a description of the model, key assumptions related to reliability criteria and reserve margin, Weighted Average Cost of Capital (WACC), forecasted demand, firm-builds and retirements, build cost of generation candidates, transmission and interface limits, technical potential for generations projects, fuel limits and fuel price projection, externality cost, and capacity credit of solar and wind. This chapter also details the modelling of six scenarios and eight sensitivities.
- Chapter 5 offers results and analysis, using the PLEXOS LT module, of the built capacity of regional interface and generators including batteries, energy generation by types at national and regional level, inter-regional flows, and cost comparison.
- Chapter 6 focuses on assessing implications for greater vRE integration in the power system in 2023, 2025 and 2030, using production cost model analysis using PASA/MT/ST phases of the PLEXOS model; the analysis pays most attention on unserved energy and curtailment.
- Chapter 7 describes the reliability analysis using NREL's PRAS tool for the three selected years (2023, 2025 and 2030).
- The Appendix provides some illustrative figures that support the PCM analysis.

[1] https://www.moit.gov.vn/web/guest/tin-chi-tiet/-/chi-tiet/bo-cong-thuong-xin-y-kien-gop-y-du-thao-đe-an-quy-hoach-phat-trien-đien-luc-quoc-gia-thoi-ky-2021-2030-tam-nhin-toi-nam-2045-21618-15.html

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We express our appreciation to Josh Novacheck, Mohit Joshi, and Jo Ann Ranola of NREL and Leon Roose, Marc Matsuura, and Thai Tran of HNEI for developing several chapters in this report and contributing to the analysis of results. We also thank Marija Prica from V-LEEP for her review and guidance during the preparation of this report. In addition, the team would like to thank Shangmin Lin, Merril Stypula, and Nguyen Duc Hanh from V-LEEP for the development and utilization of long-term (LT) visualization tools, and Bethany Speer of NREL for her continued support and coordination between the NREL team and V-LEEP.

Finally, the team would like to thank all of the members of the Modeling Working Group (MWG) for their in-kind contributions during the development and validation of the model. Specifically, V-LEEP is thankful to the staff in the Power System Development department of the Institute of Energy Vietnam (IEVN) for all of their support and collaboration in PLEXOS modeling.

ABOUT NREL

NREL is operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. NREL’s modeling work on the study was carried out under the Vietnam Grid Modernization Program funded by the Children’s Investment Fund Foundation (CIFF) in the United Kingdom.

NREL is a national laboratory of the U.S. DOE, Office of Energy Efficiency and Renewable Energy, operated by the Alliance for Sustainable Energy, LLC. under the Greening the Grid initiative, supported by United States Agency for International Development (USAID). NREL collaborates with V-LEEP to provide technical assistance to the Government of Vietnam (GVN) in strengthening its enabling environment, including its power sector planning processes, to address technical challenges around grid modernization and advance state-of-the-art practices in bringing advanced energy technologies into the power sector.

ABOUT HNEI

HNEI of the University of Hawaii at Manoa, supported this work under funding provided by the U.S. Office of Naval Research (ONR). Founded in 1974, HNEI is a research unit of the School of Ocean and Earth Science and Technology, the University of Hawai'i at Manoa that conducts research of state, national and international importance to develop, test, and evaluate novel RE technologies, advanced grid systems, and enabling policies and regulation for the effective integration of RE resources, power system optimization and energy resilience. The Institute leverages its in-housework with public-private partnerships to transfer knowledge and enable the integration of emerging technologies into the energy mix.

1 KEY FINDINGS

Key findings from this study include the following:

- Long-term (LT) modeling of the Vietnamese power sector, based on assumptions similar to the draft PDP-8, results in a significantly higher percentage of solar and wind installed capacity by 2030 compared to the revised PDP-7. This is largely driven by RE targets and the declining technology costs of solar and wind.

- The capacity expansion for different generation types from the PLEXOS-based CEM for the various scenarios is similar to that of the draft PDP-8 Version 3. Some general findings are:
  - Wind is the preferred variable RE resource due to its higher capacity factor (over 40%). However, lower financing costs for solar, relative to wind, can change the renewable build out from being dominated by wind to being dominated by solar.
  - Cost-reduction sensitivities show that lowering RE costs (through policy) can reduce the overall system costs (therefore, power tariffs) for Vietnam.
  - Expansion of solar and wind resources is coupled with flexible resources, including LNG-based internal combustion engines (ICE) and battery expansion, particularly from 2035 onwards. In the 2020's, most of the battery capacity is needed in the Northern region. However, batteries also provide flexibility to the system and they are built in all scenarios. Batteries are used by the system to provide flexibility and do not significantly improve the capacity factor of variable RE (vRE).
  - Without considering intra-regional transmission congestion, the vRE curtailment as a percentage of available vRE capacity is negligible across all the regions, except in the South-Central region. In 2025, the vRE curtailment percentage reaches 6% in the South-Central region, due to an increase in the interface congestion between Center-Central and South-Central regions. This level drops to 0.3% in 2030 as interfaces are expanded.
  - The price of LNG is a crucial factor in the choice between LNG-based and coal-based generation. However, LNG is preferred over coal for fossil fuel resources due to its lower externality costs (gas-based power generation has lower CO_2 and local air pollutant emissions). Furthermore, lower financing costs for LNG-based combined cycle gas turbines (CCGT) also allows LNG-based generators to overcome the higher fuel cost and become cheaper than new coal builds.
  - Nuclear power, the most expensive resource, is only built when CO_2 prices are high (e.g., $30/ton).
- In terms of vRE generation, solar makes up only a small percentage of the total generation, compared to wind. For example, 6.3% of generation in 2045 is from solar, compared to 27.7% from wind. This is because solar has much lower capacity factor (16.4%) compared to wind (45%).

- Interface expansion is needed in all scenarios. In particular, expansions of interfaces between the Highland and South regions and Highland and South-Central regions are needed with a large solar build-out. Inter-regional flows follow the same pattern in all scenarios. Load growth in the North and South are being served mostly by imported energy from the Central regions.

- The total fuel consumption shifts from being dominated by domestic fuels (73%) in 2020 to domestic fuels being a marginal contributor (only 20%) in 2045. Imports of fuel (LNG and coal) will rise without additional development of local gas resources.
- Batteries, internal combustion engines (ICE) and pumped storage power plants (PSPP) provide additional flexibility for the system. Flexibility is needed in the Vietnam power system even when renewable penetration stays low (e.g., in the business as usual (BAU) scenario). LNG-based CCGT resources are utilized much more than LNG-based ICE and simple cycle gas turbines (SCGT), despite having a similar amount of installed capacity—indicating the role of ICE and SCGT as flexibility resources.
- Operational and cost-reduction sensitivities show that at a lower level of vRE penetration, battery utilization is low and can be replaced by increasing flexibility in the thermal fleet. However, as vRE penetration rises above 25% of installed capacity, batteries become an important resource in the power grid operation.
- The resource adequacy analysis using NREL's Probabilistic Resource Adequacy Suite (PRAS) tool indicates that the capacity expansion of the Vietnamese power system in the Base Case meets the reliability criterion of loss of load expectation (LOLE) being less than half a day per year at the system level in 2030. However, the system is vulnerable in the mid-2020's, without additional investment in batteries, new generation plants in the North, or greater transmission expansion to the North.
- The PCM analysis identifies specific lines and interfaces that need to be expanded to have reliable supply and limit congestion/curtailment.
- The investment cost of wind expansion is the primary cost for all scenarios. Solar can be cost-competitive with fossil generation as the price of solar expansion drops.
- Interface expansion costs are only a small part of the total investment costs. Furthermore, the externality costs of emissions and the RE target are key drivers behind expansion decisions to build LNG and vRE.
- Building a High Voltage Direct Current (HVDC) expansion line between the North and South-Central regions has a significant impact on vRE capacity expansion and overall energy transfer. The HVDC line allows for more efficient usage of vRE in the system and reduces the need for new coal power plants (in the North) and the total system cost.

2 RECOMMENDATIONS AND NEXT STEPS

The analysis revealed the following key recommendations:

Ancillary Services Market: It is important for the planned ancillary services market to provide the necessary revenue for flexible generators so that they are financially viable in the Vietnamese power market.

vRE Forecasts: Better forecasts of vRE generation on an hourly and sub-hourly basis are needed to understand how the flexible resources will need to be utilized to minimize any unserved energy or curtailment in the system.

Hydropower: Hydropower plays a key role in providing the flexibility needed for integrating higher amounts of vRE into the system. Operations of multi-purpose hydropower plants are constrained by reservoir water release for agriculture. Such water releases could impact the ability of hydropower plants to provide the flexibility on an hourly and sub-hourly basis, especially as RE capacity increases on the system. Therefore, it is important to develop detailed plans for the minimum release of water from hydro reservoirs, as vRE capacity increases.

Batteries: The analysis suggests that batteries are being used mainly to provide flexibility for the Vietnam power system. Therefore, a more flexible thermal fleet (e.g., faster ramping, lower minimum operating levels) can help reduce investments in expensive flexible resources, such as high-priced batteries or pumped storage power plants (PSPP). More studies are needed to fully assess the benefits of batteries on the system with high penetration of vRE.

Domestic Resource Development: Given that Vietnam's future power system seems to be dependent on imported fuels, policy and pricing options to develop domestic resources should be considered.

Inter-regional Energy Transfer: Analysis at a higher transmission detail is recommended to assess the potential problems with energy transfer between regions.

CO_2 Pricing Structures: Small changes in capital costs (including the cost of financing) and externality costs can significantly affect future build decisions. Therefore, a more in-depth study of possible CO_2 pricing structures that are relevant for Vietnam is recommended. Evaluation of more accurate costs (based on the planned competitive bidding processes) for renewables can also help optimize the expansion decisions.

HVDC: The HVDC sensitivity analysis shows that new interfaces connecting regions can help improve operations, maximize vRE usage and reduce overall cost. Therefore, a more in-depth study of possible new transfer options between regions is recommended. To fully assess the cost/benefits of these expansions, more accurate cost estimations and environmental impacts of the new interfaces will need to be considered.

Reliability: Preliminary analysis of Vietnam's resource adequacy using the PRAS tool indicates that the country meets the LOLE reliability criterion and the typical expected unserved energy standards. However, additional analysis of the PRAS results is necessary for a more definite conclusion. Continued efforts in reliability analysis of the system is necessary to ensure the adequacy of the power system to meet demand. These analyses also need to consider the implications of demand profile changes from increased penetration of rooftop solar and other demand-side management measures.

Future Research

This study and resulting recommendations have revealed that further in-depth research is needed to better understand the economics and technical feasibility of options to increase Vietnam's grid flexibility and resilience. Future analyses should consider the following areas:

- **Regional pricing analysis** – to further review the zonal and nodal pricing from the model, as a leading indicator/signal of under- or over-capacity in the system.
- **Transmission network analysis, including congestion, –** can identify the location of the transmission needs.
- **vRE location analysis (similar to RE zones) –** can identify the best vRE resource locations.
- **Sensitivity analysis on battery storage location and duration –** can identify and quantify the battery storages beneficial in the system.
- **Inclusion of more weather years into the analysis –** can capture more uncertainties in the system.
- **Extreme weather analysis –** can examine the technical challenges of the grid during extreme weather events.
- **vRE capacity credit analysis –** can quantify the capacity value of the vRE generation that impacts the grid's reserve margin.
- **Forced outage analysis –** can capture the uncertainty in the system related to forced outages.
- **Maintenance scheduling analysis –** can improve the allocation of resources across the planning horizon.
- **Analysis of hourly chronological dispatch of coal units –** can be used to consider whether the coal units are being operated realistically, considering the technical and maintenance limitations. Such study will be useful for evaluating the potential thermal units that can provide flexibility to the grid.

3 BACKGROUND

In order to meet the challenges and uncertainties faced by Vietnam's future power sector, the process for the development of the new Eighth Power Development Plan (PDP-8) should use state-of-the-art methods, practices, and tools, and leverage planning expertise and models that have historically not been used in the PDP process. As the proportion of variable renewable energy (vRE) in the electricity generation mix increases, traditional power planning processes need to evolve to consider the unique characteristics of vRE (i.e., variability, uncertainty, and locational specificity), such as solar and wind.

In 2018, V-LEEP, with support from NREL and HNEI, proposed a methodology using a production cost model (PCM) to support MOIT and its partners to address their fundamental questions regarding the appropriate share of vRE in the PDP-8. As with conventional generation, no single model is truly capable of optimizing vRE in the power mix based on both fixed costs and operational considerations. As vRE capacity in the system increases, system operators and planners have many options to address reliability – some at no cost and some through new infrastructure and new operating practices.

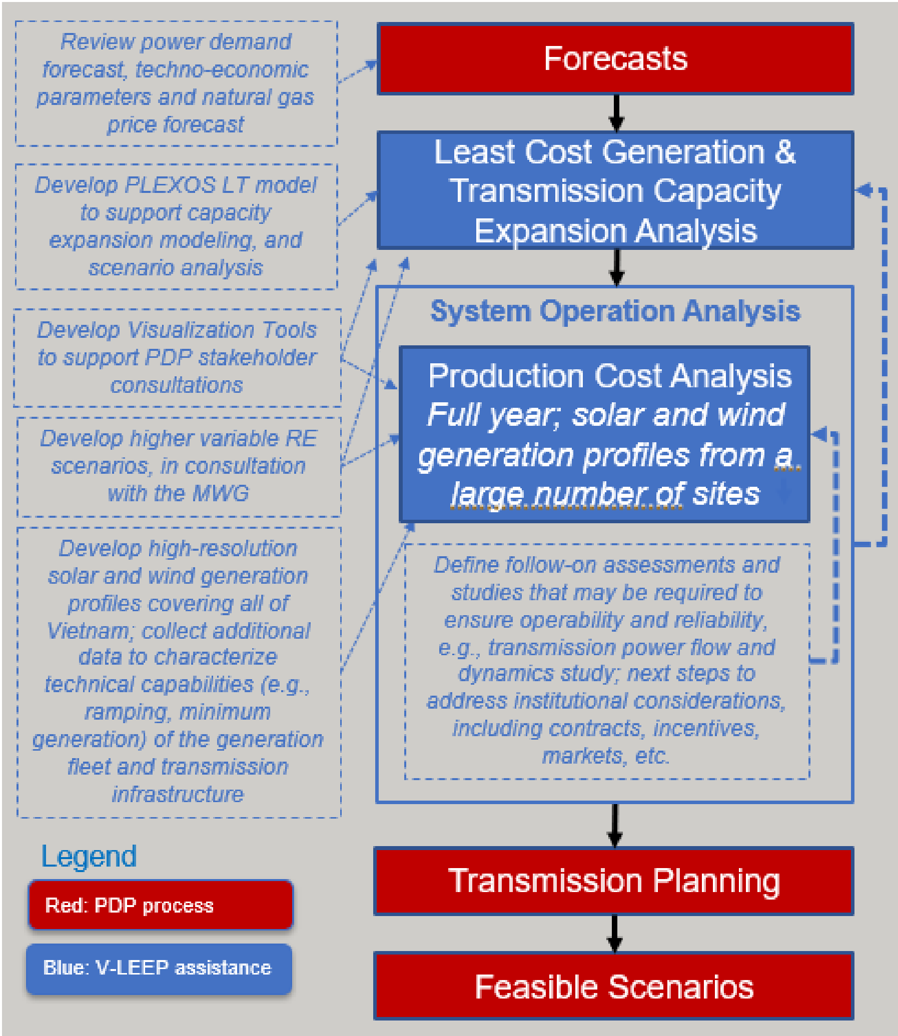
Rather than relying on long-term average capacity factors like what is usually done for conventional generation, short-term variability (sub-hourly and hourly) in solar and wind generation should be accounted for. Thus, it is necessary to evaluate all hours of the year and to perform sub-hourly analysis to sufficiently assess system benefits and risks. Operational analysis using PCM significantly improves the PDP-8 by expanding the limited analysis that was over a typical day or week for the PDP-7 and RPDP-7. More detailed stochastic analysis may also be useful to better capture generation risks associated with high RE levels in the future power system.

Planners have traditionally considered capacity expansion in terms of the need for baseload, load-following, and peaking generation capacity, with respect to a given planning reserve margin, while transmission and distribution systems were designed to accommodate peak loads. However, as larger amounts of vRE are integrated into the grid, it is important to examine the need for increasing levels of flexibility and operating reserves outside of peak times, advancements in technology such as smart grids that allow for more choices, and demand response options as they become more prevalent. These can all be evaluated in a PCM.

In order to support MOIT/EREA and IEVN to build their capacity, V-LEEP with NREL and HNEI conducted a number of different activities to support the PDP-8 development, as shown in Figure 3-1 below. These activities are captured in three reports:

a) "*Assessment and Recommendations on Methodology for Power Development Plan (PDP)*"
b) "*Assessment of Revised Power Development Plan 7 by using Production Cost Model with PLEXOS*" [the 'PCM-Report']
c) "*Impact analysis of integrating significant renewable energy in Vietnam's power sector: A PLEXOS-based analysis of long-term power development planning*" [the 'LT-Report'—this report].

Figure 3-1: Activities conducted by V-LEEP to support MOIT in PDP-8



3.1 V-LEEP RECOMMENDATIONS ON PLANNING METHODOLOGY

The methodology used for developing the previous power development plans may have been adequate in the past, but it needed to be updated for the development of the new PDP-8. As it did not sufficiently consider the short-to-medium operational elements of the power system. Therefore, V-LEEP recommended the inclusion of an analysis of power system operations in the PDP-8 development, in order to evaluate the feasibility of the capacity expansion plans determined by the long-term optimization models. New modeling tools and associated data collection were needed to support such operational analyses. Such tools and more detailed data support not only the operational analysis, but also improve the accuracy of long-term demand forecasts and transmission-needs analysis.

Moreover, the regions to be analyzed in a PDP should not be specified in legislation nor limited by what was used in previous studies. With the advent of the competitive wholesale power market and availability of new generation resources, including distributed generation, the marginal cost of power generation in a region is affected not just by physical congestion, but also by economics. As part of the overall PDP process, the determination of "model regions" should ideally be based on transmission constraints and associated locational marginal cost of generation across the country. Assessing the economic value of developing new transmission systems to relieve economic congestion would also be a part of such an analysis.

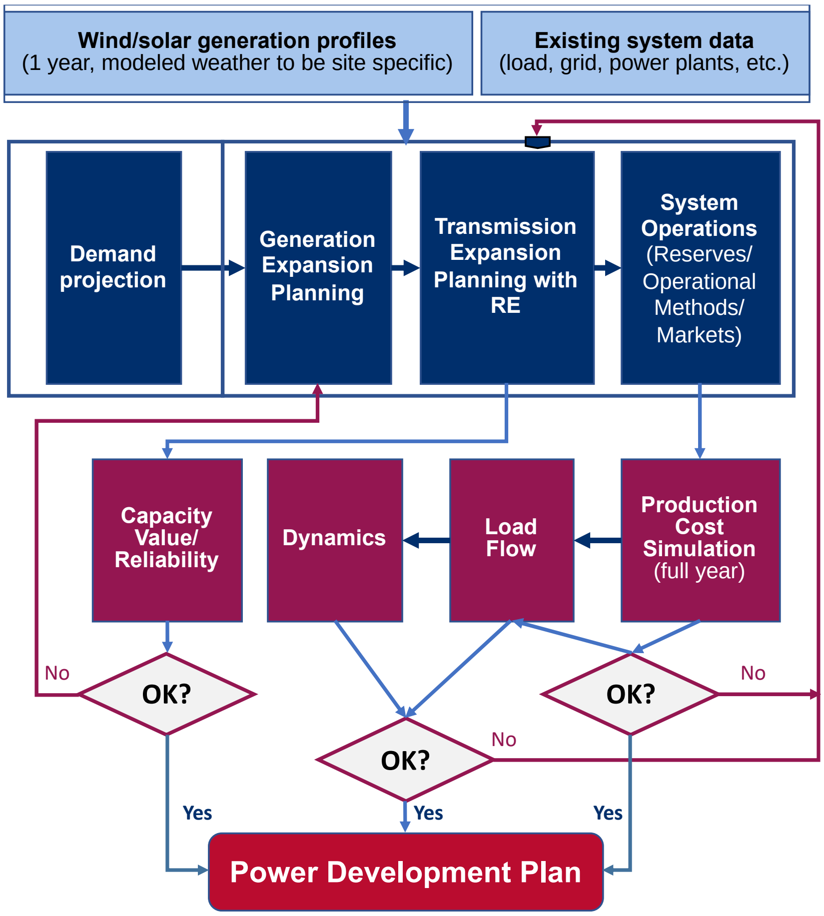
As the proportion of vRE in the electricity generation mix increases, traditional power planning processes need to evolve and consider the unique characteristics (such as variability, uncertainty, and locational specificity) of solar and wind energy integration into Vietnam's transmission grid.

Key power system planning changes related to higher levels of vRE include:

- The need for input data that characterizes the hourly or sub-hourly solar and wind generation at high spatial resolution;
- Consideration of solar and wind resource potential and geographic concentration in transmission planning; and
- The need for operational modeling (i.e., production cost simulations) that covers every period (e.g., hour, 30-minute increment) of the year, rather than only typical or average days or weeks.

The general approach of the new power system planning methodology is illustrated in the figure below, with the production cost model as an add-in module.

Figure 3-2: V-LEEP's proposed methodology for PDP-8 development



The most significant new component of the PDP-8 compared to previous PDPs was the inclusion of System Operations Analysis using a production cost model (PCM). Previous PDPs had limited operational analysis. They evaluated power system dispatch and operations only over a typical day or week to simplify calculations. Moreover, planners traditionally considered capacity expansion in terms of the need for "baseload", "load-following", and "peaking" generation capacity with respect to a given planning reserve margin, while transmission and distribution systems were primarily designed to accommodate peak loads. However, integration of larger amounts of vRE into the grid necessitates higher levels of flexibility and operating reserves from the system at times outside the peak hours.

As advancements in technology, such as smart grids and demand-response options, allow for more consumer-driven choices, it is necessary to also modify the current power dispatching rules. Such changes to operational dispatch rules need to be considered in long-term planning, as they could affect the type of new generation capacity to be built in the future. Non-transmission alternatives, such as mobilization of distributed generation resources or demand response measures, could also serve as options to reduce transmission builds and alleviate grid congestion and RE curtailment.

3.2 SUMMARY OF PCM REPORT AND KEY CONTENTS/RECOMMENDATIONS

The PCM-Report and the underlying analyses demonstrated the value of PCM in analyzing the optimal dispatch of the generators, quantifying the potential vRE generation and curtailment, and examining the future issues related to enabling greater vRE development. The report found:

- The data and assumptions in the PLEXOS PCM were validated by comparing the modeled generation in Vietnam for 2020 with the 2020 EVN Plan.
- Based on the PCM for 2030, there is a potential for a small amount of curtailment of vRE resources, which supplies approximately 6% of the generation in the grid in 2030, due to continuing network congestion mostly seen in the South.
- It is important to adequately address network congestion issues in the PDP-8 to prevent decreased coal generation, increased reliance on hydro to meet flexibility needs, and vRE curtailment.
- Drought conditions can worsen the risk of unserved energy, especially in the North, where most of the hydro generators are located.
- The Vietnam power system can economically accommodate more vRE capacity than was planned for in the RPDP-7, if sufficient flexible resources are added to the mix.
- PCM analysis of the power system at the nodal-level (as opposed to just the zonal level) provides more information for transmission grid expansion analyses, as well as for evaluating congestion and RE curtailment.

4 LONG TERM PLEXOS MODEL

This chapter describes the basics of the PLEXOS long-term (LT) model as well as the key assumptions used for the six scenarios and eight sensitivities that were tested.

4.1 MODEL DESCRIPTION

Vietnamese power system analyses are carried out with the PLEXOS model, which is a least-cost dispatch and capacity expansion model for the Vietnam power system. The model is based on a detailed technical representation of the existing power system as well as assumptions about future generation investment options.

All generation units and the transmission network (220 kV and above) are represented on an individual basis. Generators are simulated with their relevant operational properties – minimum stable generation, ramping times, minimum up/down time, start-up costs, and heat rates). Hydropower simulation uses reservoir storages with volume, natural inflow, minimum release, and monthly targets.

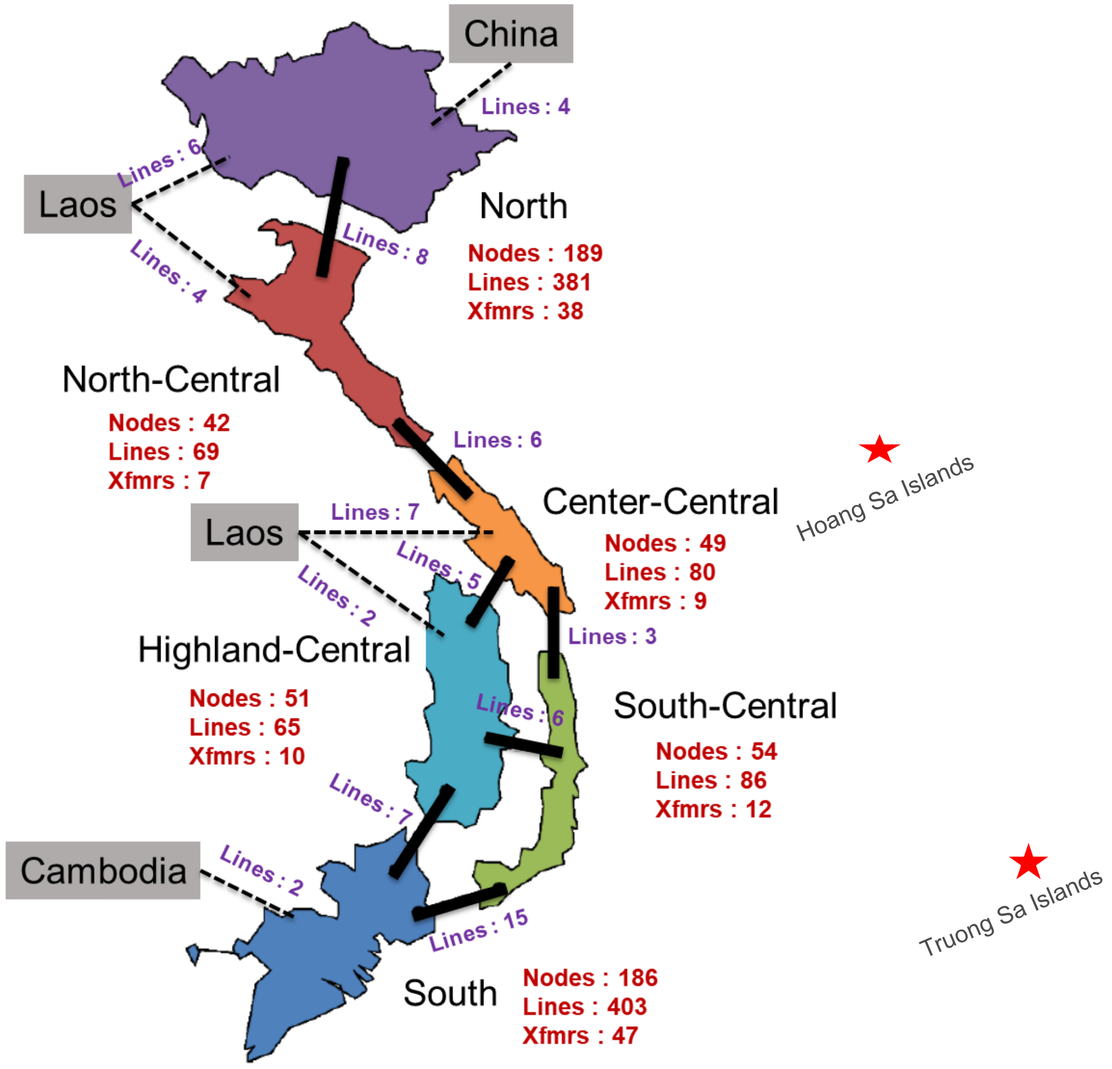
The Long-term (LT) Model or Capacity Expansion Model (CEM) is a part of the PLEXOS modelling suite. PLEXOS version 8.2R05 was used for the modelling work described here. The objective of the LT model is to minimize Net Present Value (NPV) of the combination of capital cost and production cost over the entire horizon of 26 years from 2020 to 2045. This time period matches the required time period of analysis for PDP-8, as laid out in Politburo's Resolution 55-NQ / TW dated February 11, 2020.

The model has “perfect foresight” in that the NPV costs for the entire horizon are minimized simultaneously. Capacity is built to meet the annual minimum reserve margin requirements based on peak demand, along as the capital and production cost of the new capacity is less than the cost of unserved energy.

Given the least cost optimization, it is possible that the capacity expansion could have higher than expected Loss of Load Probability (LOLP). Therefore, a separate analysis of the LOLP was conducted using other tools. In the CEM model, the power generation system is dispatched at the regional level (i.e., not the nodal level), with only the regional transmission interface limits determining the flow between the regions. The model also has the option to build new inter-regional interface capacity, in addition to generation capacity.

The Vietnam power system in the CEM model is divided into six regions (North, North Central, Center Central, Highland Central, South Central, South), and seven interfaces between regions (North – North Central, North Central – Center Central, Center Central -South Central, Center Central – Highland, Highland-South Central, Highland – South, South Central – South). See Figure 4-1.

Figure 4-1: Zones and interfaces in Vietnam power system



Note: Lines, nodes, and transformers are based on the 2030 model discussed in the PCM Report.

Five international interfaces connect Vietnam to China and Laos (China – North, Laos – North, Laos – North Center, Laos – Center Central, Laos – Highland). Imported power from China and Laos are simulated as power plants of the Vietnam power system; these "dummy plants" are not connected to China and Laos power systems. Demand from Cambodia is included in the demand of the South region.

Dispatch of generation from small hydro, solar, and wind power plants were based on hourly rating factors. The solar and wind rating factors were based on simulated weather from 2018, using weather modelling from NREL.

Electricity balances are modelled on a regional basis. For each region an electricity balance must be fulfilled, while electricity may be exchanged between regions. Annual peak load and energy demand for each region were input in the system as hourly loads for each modelled year (2020 to 2045).

While the LT model could be run with full hourly resolution, the long horizon for the models (26 years) requires the use of aggregated time steps to save computational time. The current analysis uses a load-duration curve for each region for every week of the forecast years (from

2020 to 2045). Each weekly load duration curve is divided into nine blocks biased towards peak and off-peak. This means there are 468 time-steps per year per region. For the 26 years and six regions, the LT model simultaneously solves 73,008 equations (468 x 26 x 6). The solver can be run with Linear Programing or Mixed Integer Programming; the current expansion is based on Linear Programming, similar to what has been done in the draft PDP-8. As such:

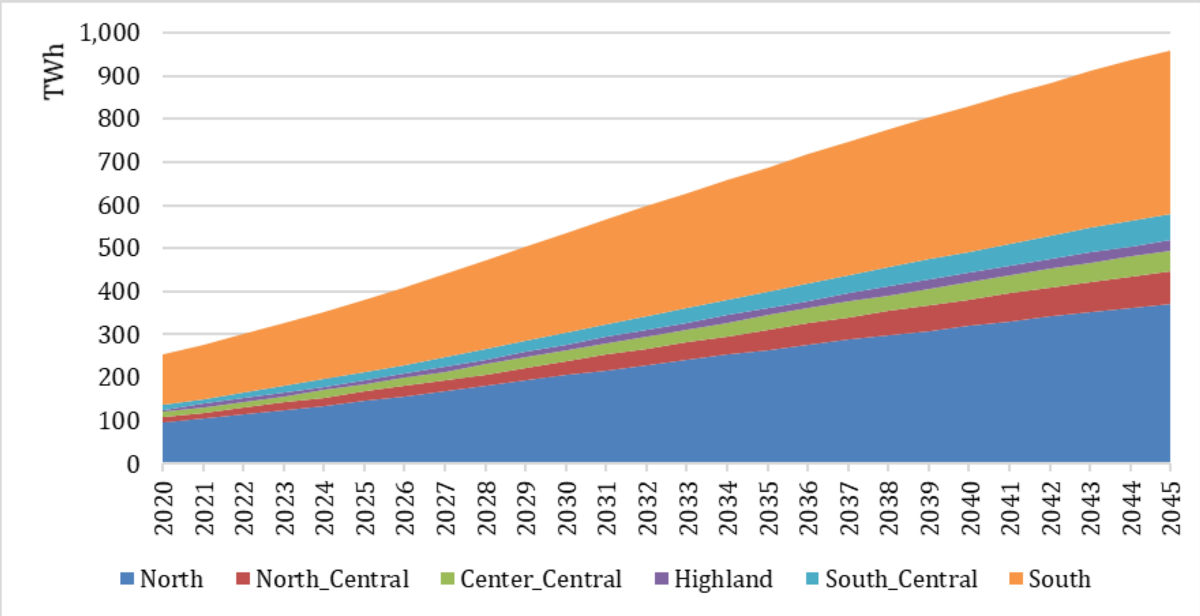
- Non-integer expansions of the generation units were separately converted to integer units when used for the annual PCM analysis.
- Expansions were assumed to be available to the power system on January 1 of each year.

4.2 KEY ASSUMPTIONS

4.2.1 FORECASTED ENERGY DEMAND IN PERIOD 2021-2045

Energy demand applied for the six regions was the same as that was applied in the draft PDP-8 Version 3. Two energy demand cases, the base case and high case, were used for this analysis. Figure 4-2 shows the growth of annual energy demand by region from 2020 to 2045; Table 4-1 provides the details for every five years.

Figure 4-2: Energy demand of six regions in Base Case from 2020 to 2045



Source: Draft PDP-8 Version 3

Table 4-1: Forecasted demand of Vietnam power system (2020-2045)

Items	Generation energy (TWh)		5-year Growth Rate of energy		Coincident Peak Demand (GW)		5-year Growth Rate of Peak	
Demand case	Base	High	Base	High	Base	High	Base	High
2020	254	254			39.5	39.5		
2025	381	394	8.50%	9.20%	59.8	61.7	8.60%	9.30%
2030	537	570	7.10%	7.70%	84.2	89.4	7.10%	7.70%
2035	688	747	5.10%	5.60%	107.9	117	5.10%	5.50%
2040	829	916	3.80%	4.20%	130.1	143.6	3.80%	4.20%
2045	959	1074	3.00%	3.20%	150.5	168.4	3.00%	3.20%

Source: Draft PDP-8 Version 3

4.2.2 FIRM-BUILDS AND RETIREMENTS

Firm-builds are prioritized projects (domestic gas, imported hydro from neighboring countries, and projects with good investment potential) that are assumed to be built in the short-term. See Table 4-2. The model does not optimize their build decisions, as they are assumed to built.

Table 4-2: Annual firm capacity additions (MW) from 2021 to 2030

Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Domestic Coal	1,200	600	600	110	600	0	0	0	0	0	***3,110***
Imported Coal	1,200	2,400	660	1,260	600	4,260	4,120	0	0	0	***14,500***
Domestic Gas	0	0	0	0	3,560	3,300	0	0	0	0	***6,860***
Imported LNG	0	1,200	0	1,500	0	0	0	0	0	0	***2,700***
Hydro	674	218	94	490	800	90	0	0	0	0	***2,365***
Small Hydro	0	0	0	0	1,956	265	0	0	0	0	***2,221***
Fuel Oil	0	0	0	0	0	0	0	0	0	0	***0***
Solar	90	0	0	0	0	0	0	0	0	0	***90***
Wind	319	0	0	0	0	0	0	0	0	0	***319***
Laos import	0	0	265	0	1,261	1,000	429	717	1,000	0	***4,672***
PSPP	0	0	0	0	0	300	300	300	300	0	***1,200***
Total	**3,483**	**4,418**	**1,619**	**3,360**	**8,777**	**9,215**	**4,849**	**1,017**	**1,300**	**0**	***38,037***

Source: Summary of the Progress report of National PDP Steering Committee – October 2020

Coal-fired and gas-fired thermal power plants are assumed to retired after 30 years of operation, and all fuel oil plants are assumed to retire by 2025. Total retirement capacity is about 18.4 GW by 2045.

4.2.3 BUILD COST OF CANDIDATE POWER PLANTS

The build cost of candidate generation plants was based on the information in the Vietnam Technology Catalogue 2019 (TC2019), which was developed for EREA with support from the Danish Energy Agency (DEA). These same assumptions were also used in the draft PDP-8 Version 3. The costs shown below in Table 4-3 include interest during construction (IDC).

They are based on the average value in TC2019. The lower build cost value for solar and wind in TC2019 was used for analyzing the low-cost sensitivity option.

Table 4-3: Build cost of candidate generation plants by vintage years (including IDC)

Technology	$/kW	Technology	$/kW
Domestic Coal Subcritical	$1500	PV solar (2020s)	$1003
Domestic Coal Supercritical	$1750	PV solar (2030s)	$886
Domestic Coal Ultra Supercritical	$2000	PV solar (2040s)	$786
Imported Coal Advanced Ultra Supercritical (2030s)	$2400	Onshore Wind - High Wind Speed (2020s)	$1450
Imported Coal Advanced Ultra Supercritical (2040s)	$2200	Onshore Wind - High Wind Speed (2030s)	$1300
LNG Combined Cycle Gas Turbine (2025-2035)	$820	Onshore Wind - High Wind Speed (2040)	$1200
LNG Combined Cycle Gas Turbine (2035 onwards)	$800	Onshore Wind - Medium Wind Speed (2020s)	$1800
LNG Internal Combustion Engine (2020s)	$700	Onshore Wind - Medium Wind Speed (2030s)	$1530
LNG Internal Combustion Engine (2030s)	$650	Onshore Wind - Medium Wind Speed (2040s)	$1380
LNG Internal Combustion Engine (2040s)	$600	Offshore Wind - Fixed base (2020s)	$3150
LNG Single Cycle Gas Turbine	$600	Offshore Wind - Fixed base (2030s)	$2570
Battery 1.5 hours (2020s)	$790	Offshore Wind - Fixed base (2040s)	$2340
Battery 1.5 hours (2030s)	$580	Offshore Wind - Floating base (2020s)	$4350
Battery 1.5 hours (2040)	$440	Offshore Wind - Floating base (2030s)	$3610
Battery 2 hours (2020s)	$910	Offshore Wind - Floating base (2040s)	$2680
Battery 2 hours (2030s)	$620	Bac Ai Hydro Pumped Storage	$840
Battery 2 hours (2040s	$480	Don_Duong Hydro Pumped Storage	$933
Battery 4 hours (2020s)	$1500	Dong_Phu_Yen Hydro Pumped Storage	$887
Battery 4 hours (2030s)	$1120	Ham_Thuan_Bac Hydro Pumped Storage	$843
Battery 4 hours (2040s)	$820	Moc Chau Hydro Pumped Storage	$726
Municipal Solid Waste	$4200	Ninh_Son Hydro Pumped Storage	$853
Biomass—straw, wood, husk (2020s)	$2000	Nuclear	$5960
Biomass—straw, wood, husk (2030 onwards)	$1890	Geothermal (small scale)	$4070
Bagasse	$1500		

Source: Average case of technologies in the Vietnam Technology Catalog 2019, DEA; and PDP-8

For the investment cost of RE projects (wind and solar) and batteries, there are three forecasting perspectives: Conservative, Harmonious, and Optimistic. These perspectives are similar to the assumptions in the draft PDP-8. For example, IRENA forecasts are considered as "Optimistic", as their investment cost of renewable energy is lower than other forecasts. This low-to-high predictive range is also included in the Vietnam Technology Catalogue 2019. In this study, we use the Harmonious forecast for RE capital expenditure (CAPEX) for the Base Case scenario and the Policy-based scenarios (see below). In a sensitivity analysis, the Optimistic case of low RE investment cost is considered to evaluate the implications of possible lower technology costs. The build cost assumptions for the Harmonious and Optimistic CAPEX scenarios are presented in the following table:

Table 4-4: Build cost under Harmonious & Optimistic perspectives

TT	Year	Offshore Wind Fixed base	Offshore Wind Floating base	Onshore Wind High Speed	Onshore Wind Medium Speed	Solar PV	Battery 2h

1	**Base (Harmonious) CAPEX in USD/kW (By medium level in Technology catalog 2019)**						
	2020-2029	$3150	$4350	$1450	$1800	$1003	$910
	2030-2039	$2570	$3610	$1300	$1530	$886	$620
	2040-2049	$2340	$2680	$1200	$1380	$786	$480
2	**Lower (Optimistic) CAPEX in USD/kW (By lower level in TC2019)**						
	2020-2029	$2950	$4150	$1400	$1650	$890	$709
	2030-2039	$2220	$3120	$1150	$1350	$620	$334
	2040-2049	$1900	$2130	$1050	$1150	$510	$270

4.2.4 WEIGHTED AVERAGE COST OF CAPITAL

The weighted average cost of capital (WACC) is assumed to be 10% for all candidates of generation technology in the Base Case. As a sensitivity, lower WACC was set for gas (9%), solar (8.75%), wind (9%), battery (9%), and interfaces (8.5%), with the assumption of perceived lower risks from international financial institutions for constructing these technologies. Similarly, a higher WACC was assumed for coal builds (12%) in the sensitivity case.

4.2.5 TECHNICAL POTENTIAL FOR GENERATION PROJECTS

There are limits to the technical potential of installed capacity for various power plants. The technical maximum of coal-fired thermal power plants and CCGT capacity using LNG is based on the summary of investment registration projects and preliminary assessment of potential construction sites in coastal provinces. The maximum potential for candidate thermal projects is summarized in Table 4-5. Potential capacity limits for renewable energy power plants are based on the techno-economic potential that was evaluated in the draft of PDP-8 Version 3 and shown in Table 4-6.

Table 4-5: Maximum potential (MW) of coal-fired and LNG-CCGT power plants

Region	Imported coal-fired power plant (MW)	CCGT using imported LNG (MW)
North	19,100	29,000
North Central	6,050	11,000
Center Central	9,200	16,000
South Central	9,200	21,750
South	16,200	34,250
Total (MW)	**59,750**	**112,000**

Source: The draft PDP-8 Version 3

Table 4-6: Maximum potential of RE (MW) included in the PLEXOS LT

Region	Offshore wind	Onshore wind (> 4,5m/s)	Solar (farm)	Solar (rooftop)	Biomass	Small hydro power	Waste	Geothermal
North	13,000	12,565	14,600	10,724	1,611	1,474	359	255
North Central	5,000	10,717	3,350	5,542	548	242	65	51
Center Central	0	11,235	10,300	3,521	336	410	33	77
Highland	0	74,386	117,600	2,448	663	384	14	0

Region	Offshore wind	Onshore wind (> 4,5m/s)	Solar (farm)	Solar (rooftop)	Biomass	Small hydro power	Waste	Geothermal
North	13,000	12,565	14,600	10,724	1,611	1,474	359	255
North Central	5,000	10,717	3,350	5,542	548	242	65	51
Center Central	0	11,235	10,300	3,521	336	410	33	77
South Central	118,000	34,764	81,000	4,165	521	278	46	60
South	26,200	73,638	110,000	22,091	1,638	70	999	18
Total	**162,200**	**217,305**	**336,850**	**48,491**	**5,316**	**2,860**	**1,517**	**461**

Source: The draft PDP-8 Version 3

For imported power from neighboring countries, capacity of potential import projects can reach up to 19 GW from China, Laos, and Cambodia. However, the import of electricity will depend on the political conditions and cooperation among countries. Therefore, in order to ensure domestic energy security, the study fixed the amount of import capacity, similar to draft PDP-8, as follows:

- 700 MW from China
- ~2,500 MW in 2025 and about 5,000 MW in 2030 from Laos (based on the 2016 memorandum between the Government of Vietnam and Laos).

The total import capacity through 2030 is 5,500 MW, with energy imports of about 21-22 billion kWh/year.

Nuclear power is also included in the model in eight potential locations in South Central (Binh Dinh, Ninh Thuan, and Phu Yen provinces), Center Central (Quang Ngai province), and North Central (Ha Tinh province) as prescribed in Prime Minister Decision No. 906/QD-TTg (June 17, 2010) describing the planning of nuclear power development. A maximum of 5,000 MW of nuclear power capacity is assumed.

4.2.6 RELIABILTY CRITERIA OR RESERVE MARGIN

The reliability criteria for the Vietnam power system in this study applies the same criteria as employed in the PDP-8 in which the Loss of Load Expectation (LOLE) is set to less than 12 hours/year in all six regions. To calculate the capacity expansion, the assumption of reserve margin is first set in the model. The reserve margin in this study was set for the entire Vietnam power system at 20% from 2021 to 2026. It was then gradually reduced to 18% in 2030, 15% in 2035; and then remaining at 15% beyond 2035.

Calculations of the multi-region LOLE from PLEXOS were reviewed for each region to check that the reliability criteria were met. However, a more complete analysis of the system reliability was conducted using the NREL tool, “Probabilistic Resource Adequacy Suite (PRAS)”, based on the PCM model (See Chapter 7). If necessary, further analysis of the system can consider alternative options for the reserve margin based on more detailed reliability analysis in the future.

4.2.7 CAPACITY CREDIT OF SOLAR AND WIND

To date, the ability of solar and wind capacity to provide reserves to meet peak demand in Vietnam has not been studied in great detail. As such, knowledge of the capacity credit of wind and solar power in Vietnam is limited. According to research conducted in other countries, the guaranteed capacity range of wind and solar power varies widely, from as low as 4% to as high as 10-20%. In this study, we assume a vRE capacity credit in Vietnam of 20% for solar and 20% for wind. This means that 20% of solar and wind installed capacity is considered firm and included in the capacity used to meet reserve margin requirements.

4.2.8 TRANSMISSION AND INTERFACE LIMITS

For the LT model, “N-1” transmission limits of year 2025 was used. After 2025, the LT model was allowed to expand the interface capacity, as necessary.

Table 4-7: Capacity of main interfaces in the Vietnam power system in 2025

Interface	Thermal Limit (MW)		N-0 (MW)		N-1 (MW)	
	For	Back	For	Back	For	Back
North - North Central	6130	-6130	3469	-3469	2055	-2036
North Central - Mid Central	5140	-5140	5140	-5140	2700	-2500
Mid Central - High Land	8460	-8460	8460	-8460	5700	-5700
Mid Central - South Central	1000	-1000	1000	-1000	262	-308
High Land - South Central	2200	-2200	1880	-1880	664	-543
High Land - South	8446	-8446	7900	-2900	5351	-2259
South Central - South	13430	-13430	13533	-2533	10193	-2172

Source: Calculation from grid planning group in the PDP-8 project

An additional interface from South Central-to-North was analyzed as a sensitivity representing the potential of an HVDC transmission line to transmit power from the South-Central region to the North region. Regional wheeling charges (see Table 4-8) were also included in the model to simulate transmission losses and transmission fees in the LT objective function.

Table 4-8: Wheeling charge between regions

From	To	Wheeling charge ($/MWh)
North-Central	North	2.37
Center-Central	North-Central	3.13
Highland-Central	Center-Central	1.56
South-Central	Center-Central	2.98
South-Central	Highland-Central	2.07
Highland-Central	South	2.8
South-Central	South	1.86

Source: Calculation from grid planning group in the PDP-8 project

4.2.9 FUEL LIMITS

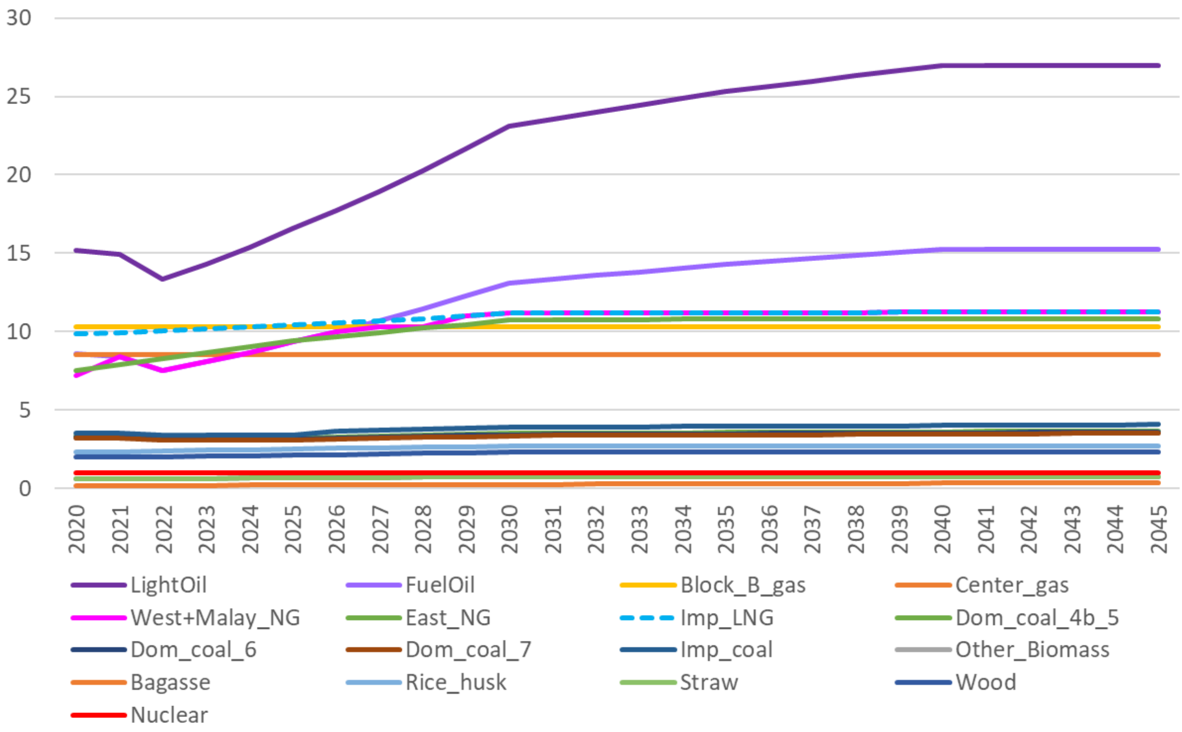
Maximum fuel availability caps the annual use of domestic coal and domestic gas based on the reserve and exploiting ability. Similar to the draft PDP-8, the total domestic gas supply capacity for electricity production is expected to increase from 7.7 billion m^3/year in 2020 to 14.6 billion m^3/year in 2025. After 2025, domestic gas output supplied to electricity will gradually decrease, reaching about 9.2 billion m^3/year by 2030 and remaining at 7.7 billion m^3/year after 2035. Based on existing contracts, domestic gas also has a 90% minimum take-or-pay constraint.

The total domestic coal production that can be supplied for electricity was assumed to be about 35 million tons per year in 2020, about 36.3 million tons per year in 2025, about 39.8 million tons per year in 2030, and remaining at 39.5 million tons per year from 2035 onwards.

4.2.10 FUEL PRICE PROJECTION

Figure 4-3 shows the projection of fuel prices used in the model, with oil prices based on the International Energy Agency and the Energy Information Agency. Imported LNG prices are not linked to oil prices and it is assumed to be based on contracted prices (potentially linked to Henry-Hub). However, the LNG prices are very high ($11/GJ) and close to domestic gas prices. Lower LNG prices at $9/GJ and $6.7/GJ are considered as potential sensitivity scenarios.

Figure 4-3: Fuel price projection in USD/GJ to power plants



Source: Fuel forecasted price used in Draft PDP-8 Version 3, International Energy Outlook 2018, EIA

4.2.11 RENEWABLE ENERGY TARGETS

Annual RE targets are included in the model based on the proportion of generation that is from renewable energy sources (including large hydro) relative to the total generation of electricity in Vietnam. Similar to the draft PDP-8, this study included two RE target scenarios including:

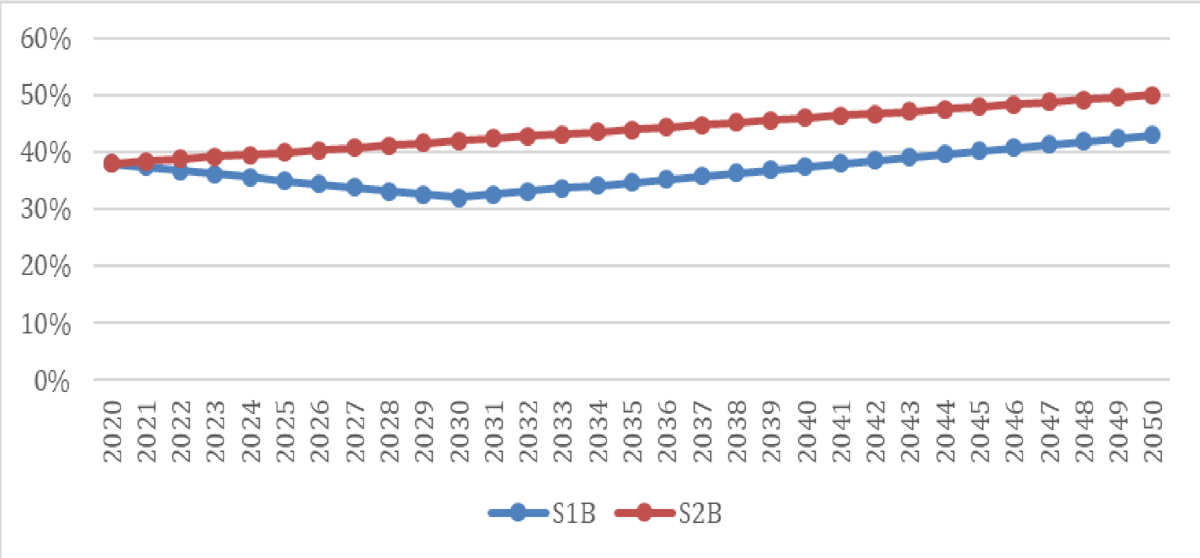
- Current RE target (S1B) for the Base Case scenario based on Renewable Energy Development Strategy
- High RE target (S2B) for the High RE Target scenario

The current RE target is in line with the overall goal in the Vietnam Renewable Energy Development Strategy for the period up to 2030 with a vision to 2050 (Decision No. 2068/QĐ-TTg dated November 25, 2015) and Resolution 55-NQ/TW. Accordingly, the *minimum* proportion of generated energy from renewable energy sources (including large hydro power plants) relative to the total nationwide generated energy will reach 38% by 2020, 32% in 2030, and 43% in 2050.

The high RE target scenario assumes a policy with a more ambitious target than the approved Renewable Energy Development Strategy. It is expected that the RE target will gradually increase linearly from 38% in 2020 to 50% in 2050.

Note that if the economics allow for it, the model can choose to build more RE capacity to generate energy that is higher than the targets. In other words, if investment costs in RE capacity is relatively lower than other options, the model can choose to build and generate more than the RE targets.

Figure 4-4: Minimum proportion of RE generated energy (including large hydro)



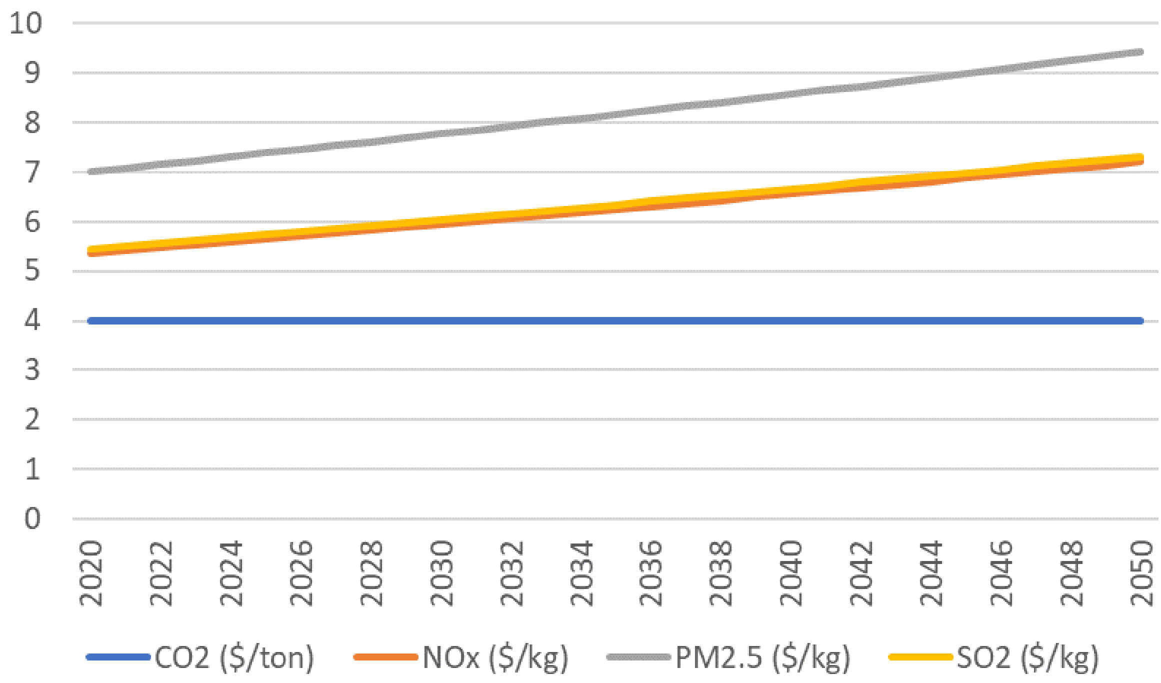
4.2.12 EXTERNALITY COST

CO_2 emissions are modeled from the fuel consumed by power plants. SO_x, NO_x, and PM2.5 emissions are modelled as emissions from the kWh generated from thermal power plants. The PLEXOS LT model includes externality costs in the objective function, which can alter the build patterns based on the cost of these externalities. See Figure 4-5 for the cost trends of these emissions.

Similar to the PDP-8 Version 3, using the cost of damage to human health, the price of CO_2 is quite low—below US$1/ton for developing countries. The draft PDP-8 used a CO_2 price of about US$0.40/ton. This is equivalent to the average transaction price of CO_2 in the global CO_2 market in 2019. However, according to the EU Technical Assistance Program for Sustainable Energy, which supports the EREA to carry out a Strategic Environmental Assessment, a low scenario CO_2 shadow price is proposed to be around US$4/ton from 2020 onwards. This price of US$4/ton is being used in the model.

In this study, alternative CO_2 price sensitivities were also considered—at US$30/ton and US$100/ton. In the *\$30 CO_2* sensitivity, CO_2 prices increase linearly from US$4/ton in 2020 to US$30/ton in 2030 and remain flat thereafter. In the *\$100 CO_2* sensitivity, prices increase linearly from US$4/ton in 2020 to US$100/ton in 2035 and remain flat thereafter. These prices are large enough to make a significant impact on build decisions in the future, providing insight to a scenario in which the Government of Vietnam decides to use CO_2 prices as a means to control future CO_2 emissions.

Figure 4-5: Cost of emissions from power plants



Sources: Valuation of some environmental costs within the GMS Energy Sector Strategy – ADB, 2007, Getting Energy Prices Right – from principle to practice – IMF, 2014

Similar to the draft PDP-8, one of the scenarios in this study also considered the effect of limiting CO_2 emissions, which then results in shadow prices for CO_2 emissions. See below.

Note that the externality costs in this study were fixed and did not take into account price slippage because the costs are attributable to 2016 (excluding annual price slippage).

Other externalities that were added to the capital costs of relevant power plants include:

- **Land-use costs:** 6-8 USD/m^2. *Source: Provincial People's Committees decisions on land price lists updated to January 2020*
- **Cost of processing the solar panels:** 200 Euro/ton at the end of the project. *Source: End_of_life management for Solar PV panels - IRENA, June 2016*
- **Cost of chemical treatment for Li-ion battery:** The cost of disposing of lithium-ion: 5000 USD/ton. Waste norm of Li-ion battery: 0.112 kWh/kg. *Source: Argonne National Laboratory (USA)* *https://batteryuniversity.com/learn/article/bu_1006_cost_of_mobile_power*

4.3 SCENARIOS AND SENSITIVITIES

4.3.1 POLICY-BASED SCENARIOS

The LT model considered a variety of “policy-based” scenarios, including assumptions from currently issued policies and from hypothetical future policies. These various policy sets allow the GVN to fully consider the development potential and implications of choosing to build different types of power sources in the future. The LT model considered six policy scenarios:

1. **Business as Usual (BAU) – BAU without externality cost:** No new policies are included in the model. Future power sources are selected based on cost competitiveness; externality costs are not included in the model objective function. This scenario is presented as a baseline to evaluate the effectiveness of the proposed policies in the following scenarios. This scenario is equivalent to the “S0A scenario”, as presented in the draft PDP-8 Version 3.

2. **Base Case – Base Case with Current RE target and externality costs:** This scenario is based on the RE target under the Vietnam Renewable Energy Development Strategy for the period up to 2030 with a vision to 2050 (Decision No. 2068 / QD-TTg dated November 25, 2015). Accordingly, the proportion of generated energy from RE sources (including large hydro) relative to the total energy generated in Vietnam will range from a minimum of 32% in 2030 and reach 43% in 2050. The rate of RE-generated energy increase under this strategy is also consistent with the Politburo's Resolution 55-NQ/TW dated February 11, 2020. This scenario is equivalent to the “S1B scenario”, as presented in the draft PDP-8 Version 3.

3. **High RE Target – High RE target with externality cost:** This is a hypothetical policy scenario considering a more ambitious RE target (see S2B target above in Section 4.2.11) than the approved Renewable Energy Development Strategy. It is expected that the ratio of generated energy from RE (including large hydro) relative to total electricity generated nationwide will gradually increase linearly from 38% in 2020 to 50% in 2050. This scenario is equivalent to the “S3B scenario”, as presented in the draft PDP-8 Version 3.

4. **GHG Limits – Current CO_2 reduction target, with externality cost:** In its Nationally Determined Contributions (NDC-2019) under the Paris Agreement, Vietnam has committed to reducing GHG emissions from 9% in BAU to 27%. The total emissions of the country are not only due to the electricity sector but also from other industries. However, the electricity sector typically accounts for a large proportion of industrial emissions. Therefore, instead of using RE targets, this scenario considers the change in power source structure with a 25% reduction in greenhouse gas emissions compared to the BAU scenario.

5. **No New Coal** – **Current RE target, no new coal after 2030, with externality cost:** This scenario combines the Base Case RE target policy with a hypothetical policy that does not develop new coal-fired power plants after 2030. This scenario is calculated with the externality costs of emissions in the model objective function.

6. **Nuclear** – **Current RE target, with nuclear, with externality cost:** This scenario combines the Base Case RE target with a hypothetical policy that requires the

development of nuclear power after 2035—at least 1,000 MW in 2035 and 5,000 MW in 2045.

These six policy-based scenarios are based on the following assumptions:

- Hydrological parameters of hydropower plants are an average of many years (Source: *Annual Operation Statistics of NLDC*, research on hydrological data of hydropower projects in Vietnam is sponsored by JICA in 2004).
- Wind and solar profiles are based on the 2018 RE profiles developed by NREL to support the clean energy transition in Vietnam, including for offshore wind.
- Demand forecast is the same as the base case of the draft PDP-8 Version 3.
- Fuel price is forecasted as presented above.
- Capital costs of each generation technology uses the average costs in the reference documents of international organizations, as noted above.

4.3.2 SENSITIVITIES OF BASE-CASE SCENARIO

Currently, the draft PDP-8 Version 3 has selected assumptions similar to the *Base Case* scenario of this study (Current RE target, with externality cost). Therefore, the sensitivity analysis was conducted based off of this scenario. Sensitivities tested can be broken into three main categories as described below:

Sensitivities that change the specific assumptions of the Base Case, include the following:

- **Sensitivity – No Externality Cost:** All assumptions are the same as the Base Case, but without any externality costs for emissions

Operational Sensitivities: Sensitivities that change the operational features of the Vietnam power system, include the following:

- **Sensitivity – High Demand:** Higher energy and peak power demand for each region.
- **Sensitivity – $30 CO2:** Increased CO2 prices from US$4/ton to US$30/ton, as a hypothetical possibility to test how the system may react to higher prices. An additional sensitivity of US$100/ton was also tested as an extreme case.
- **Sensitivity – Dry year:** A 20% reduction in electricity generated from hydroelectricity compared to the Base Case, implying a "dry year" scenario throughout the entire planning horizon.
- **Sensitivity – HVDC:** A 1,500 km, 6 GW capacity HVDC line is built from the South Central region to the North region in 2030.

Cost-Reduction Sensitivities: Sensitivities that change the investment costs of different resources.

- **Sensitivity – Low RE Cost:** Lower investment cost of solar/wind/battery
- **Sensitivity – Diff WACC**: Differential WACC. Assumed WACC for coal fired power plants is 12%, gas fired power plant and wind power plant is 9%, solar power plant is 8.5%
- **Sensitivity – Diff WACC + Low RE:** Combination of scenarios with differential WACC and lower investment cost

5 RESULTS AND ANALYSIS OF LT MODELING

In this chapter, the LT modeling results are presented with a focus on the built capacity (generators and interfaces) for the various scenarios and sensitivities discussed above.

5.1 BUILT CAPACITY RESULTS

5.1.1 GENERATORS

Figure 5-1 shows the built capacity expansion (not including the firm-builds in Table 4-2) for the Base Case as well as the total installed capacity for the Base Case in five-year increments. Major capacity expansion (both firm and model-selected builds) was built from 2020 to 2025. From 2026-2030, due to a large number of firm-build imported coal and domestic gas units coming online, as shown above in Table 4-2, the need for model-built capacity expansion is smaller, as the firm-build capacity meets most of the load growth in this period. After 2030, when all the scheduled firm-builds have come online, the model-built capacity expansion increases again. LNG and wind are the dominant resources in the thermal and vRE categories.

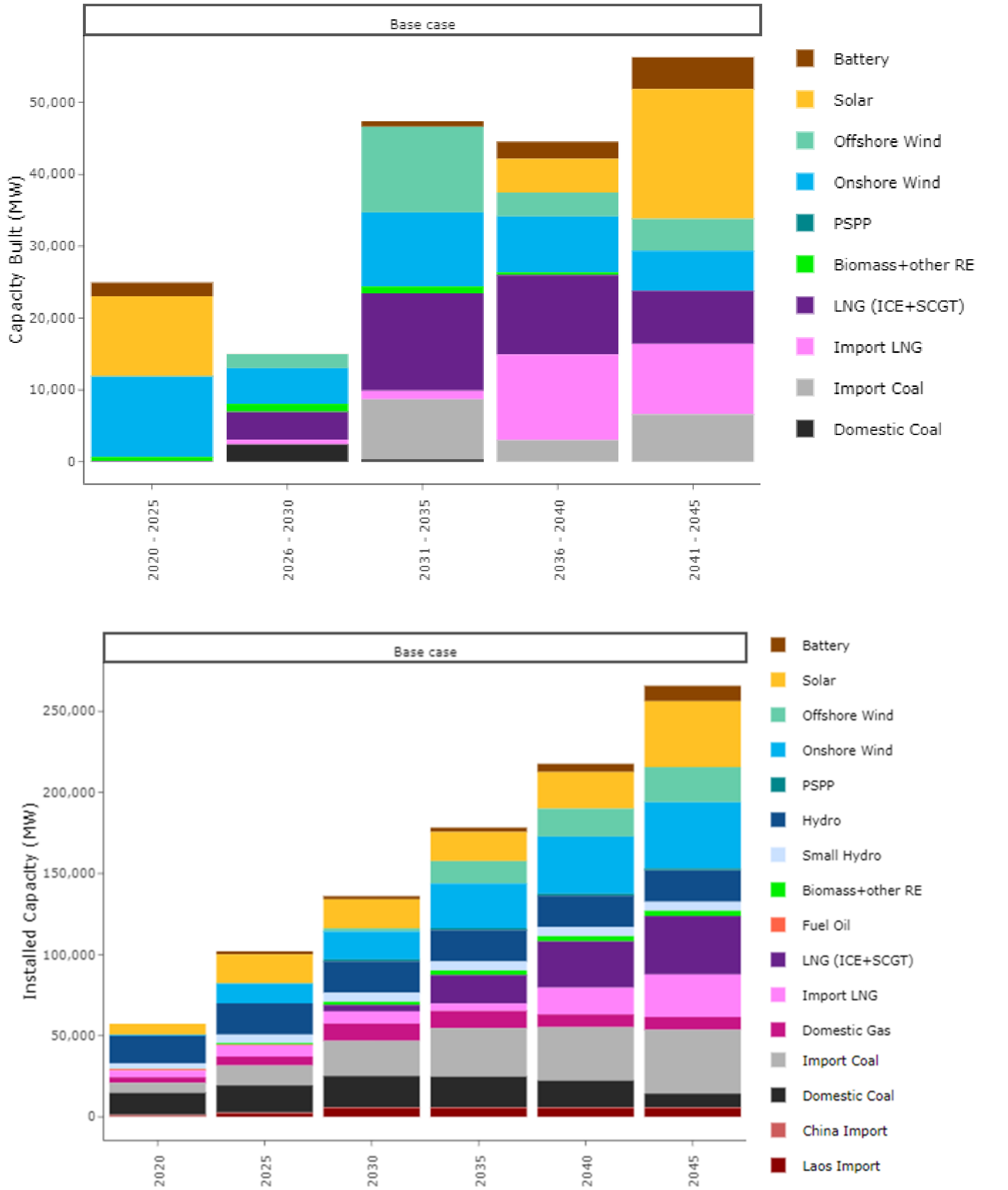
As shown in Figure 5-1, the model favors building out wind resources before solar due to the higher capacity factor for wind, which yields superior economics. Most of the wind resources get built in the first 15 years, while most of the solar resources get built in the last 5 years. Furthermore, as more wind generation is built in the 2030's, there is a greater need for flexible resources that is primarily provided by LNG-based internal combustion engines (ICE). In the later years after 2035, solar expansion is coupled with battery build out. For fossil resources, the model prefers LNG (import[2] and ICE+SCGT) over coal due to lower emissions cost, particularly in the later years after 2030. In the LNG (ICE+SCGT) category, ICE expansion makes up the majority in all scenarios and sensitivities. A breakout of ICE and SCGT expansion for the Base Case in five-year increment is shown in Table 5-1.

Table 5-1: ICE and SCGT Capacity for the Base Case

Year	ICE Capacity (MW)	SCGT Capacity (MW)
2020	0	0
2025	104.82	0
2030	2,504.82	1,442.63
2035	12,504.82	5,018.10
2040	22,304.82	6,273.34
2045	29,704.82	6,273.34

[2] Import LNG category refers to the gas turbine generators that use imported LNG as fuel.

Figure 5-1: Built Capacity (top) and Installed Capacity (bottom) for the Base Case



The resource mix in 2045 is made up of 54.5% fossil and 45.5% renewable resources, up from 35.18% renewable in 2020. The resource mix for the Base Case in five-year increments is shown in Table 5-2. Note that the RE generated energy is higher than the Base Case RE target (S1B), indicating that the new RE plants (solar and wind) are economically built, regardless of the RE target.

Table 5-2: Resource Mix for the Base Case

Year	Fossil (%)	RE (%)
2020	64.82	35.18
2025	57.06	42.94
2030	61.35	38.65
2035	53.33	46.67
2045	54.48	45.52

Figure 5-2 shows the built capacity and installed capacity for the policy-based scenarios in five-year increments. Some of the key highlights are:

- All policy-based scenarios (except for the BAU scenario which has no RE targets and no externality costs) show a similar capacity expansion pattern. Wind is the preferred vRE resource due to its higher capacity factor. Most of the solar and battery expansions are built in the last 10 years of the modeled horizon.

- The rate of LNG-based CCGT expansion in all scenarios increases in the later years due to higher externality cost of emissions.

- In general, the *High RE Target* and the *No New Coal* scenarios have the most solar capacity.

- The BAU scenario has the lowest amount of installed capacity because without the RE target or externality costs, it does not need to build as much solar and wind capacity. Without the externality costs in the BAU scenario, coal expansion is favored over LNG and renewables.

- Even with a small amount of solar in the system, the BAU scenario still builds battery capacity comparable to other cases. This suggests that flexibility is needed by the model even when renewable penetration is low.

- In the *No New Coal* scenario, more LNG-based CCGT is built in place of additional coal build out in the other scenarios.

- Because of its high cost, nuclear units are only built when required in the *Nuclear* scenario. Furthermore, the relatively low cost of CO_2 emissions used in the *Base Case* externality costs does not promote investment in nuclear capacity. Even in the *GHG Limit* scenario, the reduction of GHG emissions relative to the *BAU* scenario is not high enough to support investment in nuclear plants.

Figure 5-2: Built Capacity (top) and Installed Capacity (bottom)—Policy-based Scenarios

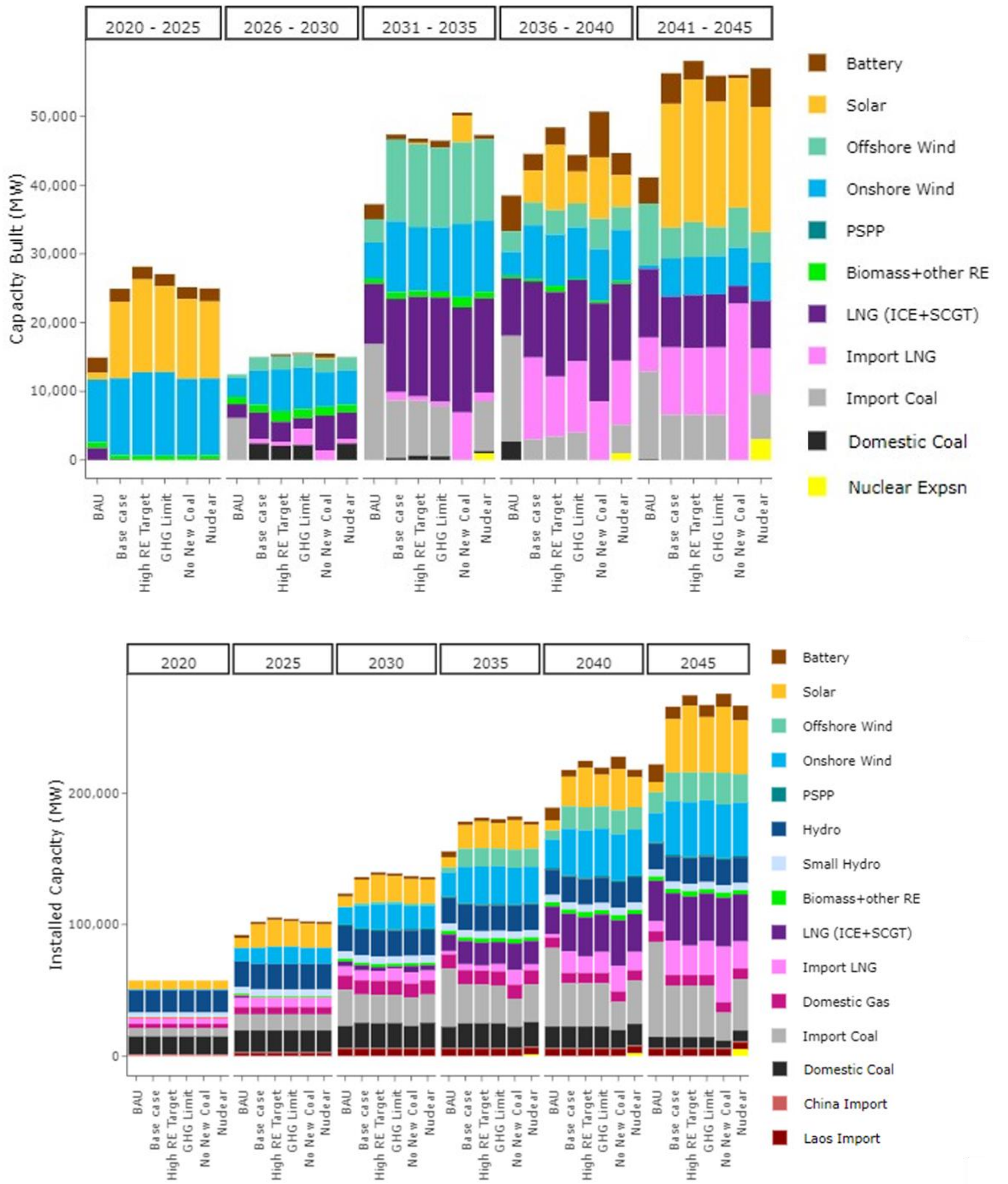


Figure 5-3 shows the built capacity and installed capacity for the *No Externality Cost* sensitivity, relative to the Base Case, in five-year increments. Without emissions cost, more coal power plants (using both domestic and imported coal) are built, and the number of power plants based on imported LNG is reduced. Because of the RE target, RE resources are still built, but wind and solar capacities are reduced compared to the Base Case.

Figure 5-3: Built Capacity (top) and Installed Capacity (bottom) for No Externality Cost

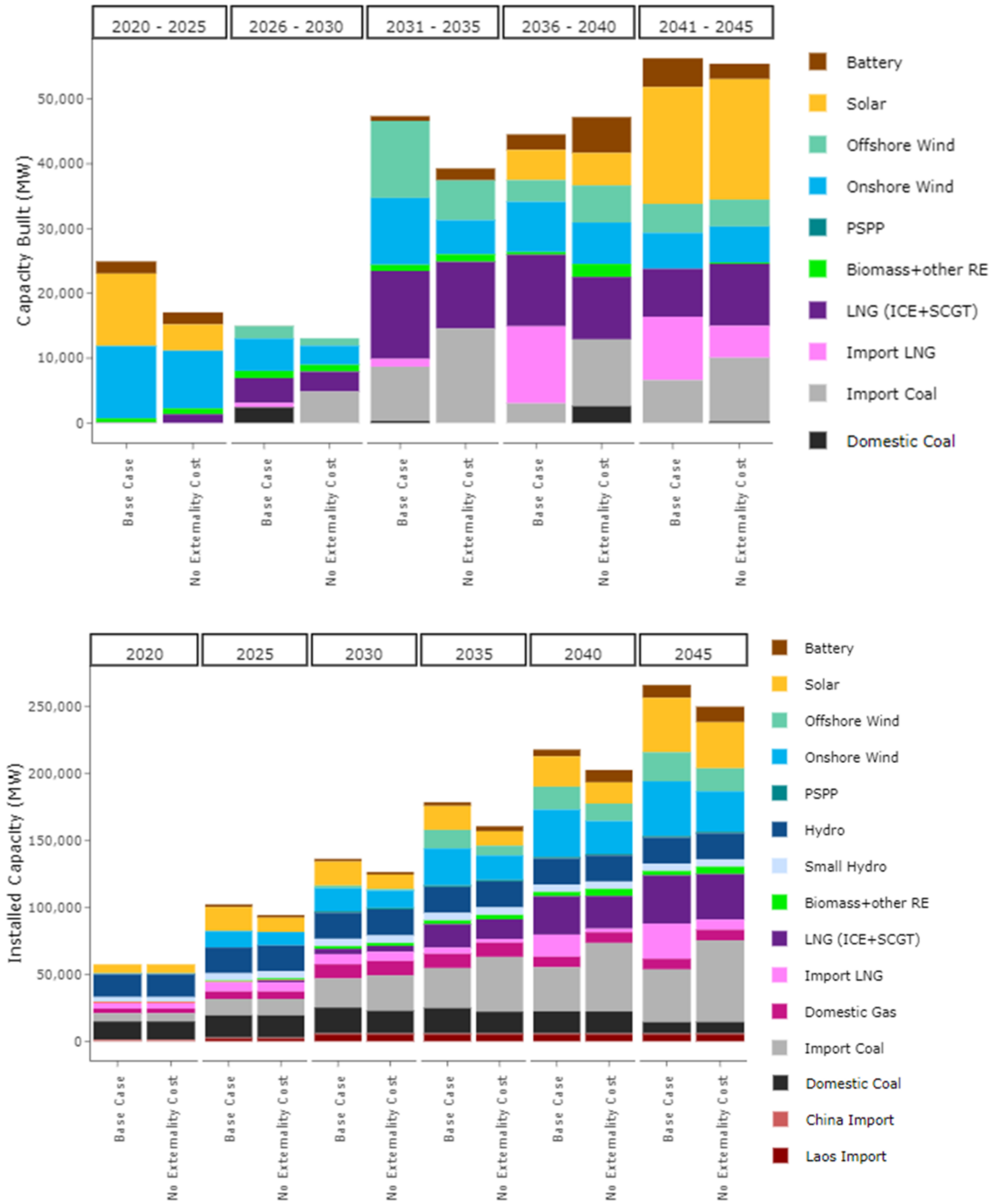
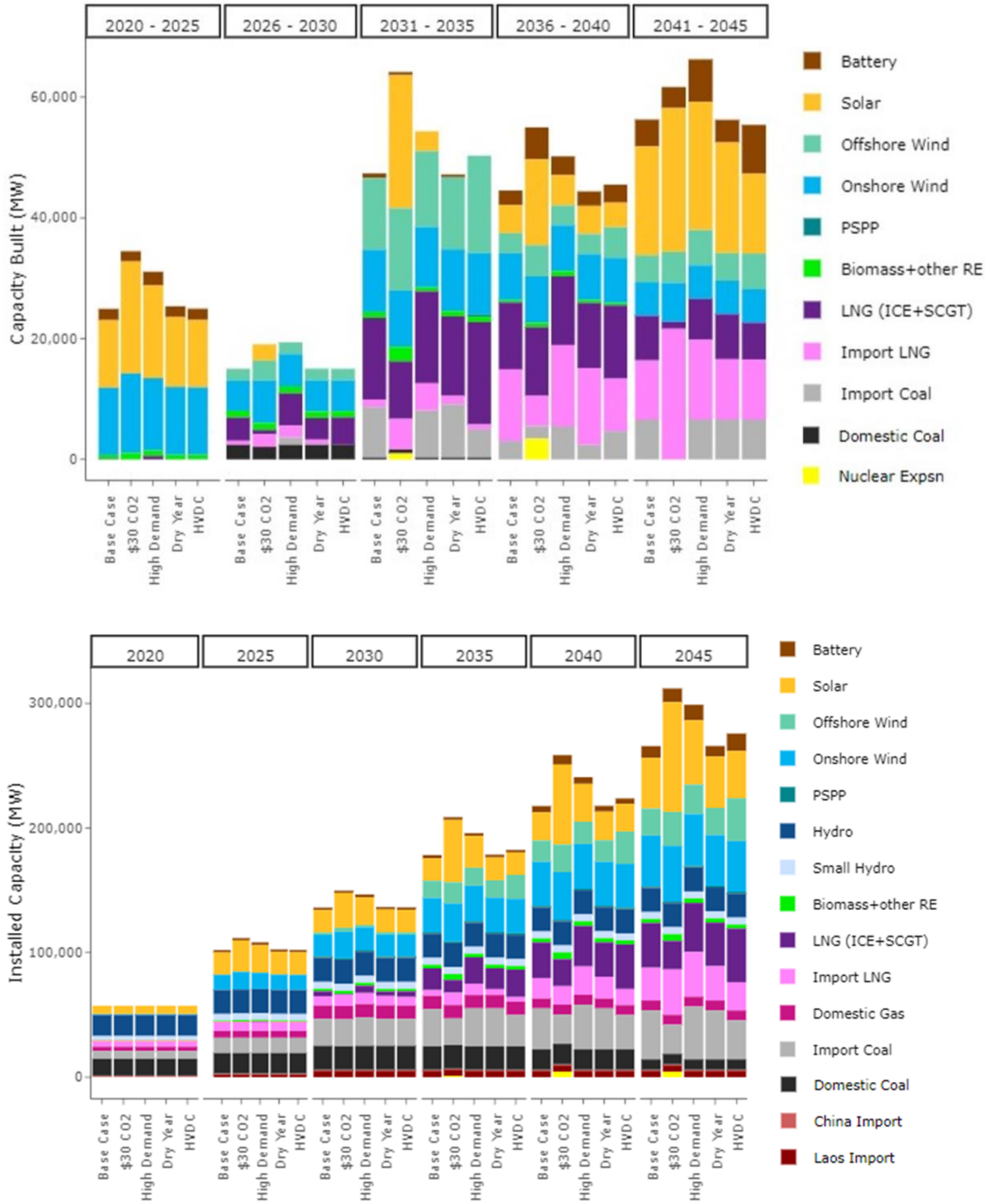


Figure 5-4 shows the built capacity and installed capacity for the operational sensitivities in five-year increments. For the long-term planning, reduced water inflows in the *Dry Year* sensitivity does not significantly affect the build decisions because hydro resource is not one of the expandable resources and makes up a relatively small amount of total capacity expansion by 2045. However, the shortfall in hydro generation in the *Dry Year* sensitivity was made up by small increases in imported LNG and slightly higher vRE expansion.

Figure 5-4: Built Capacity (top) and Installed Capacity (bottom) for the Operational Sensitivities



Unsurprisingly, the capacity expansion in the *High Demand* sensitivity is higher in all categories to meet the higher energy demand. Compared to the *Base Case*, the *High Demand* sensitivity has greater expansion in LNG-based CCGT, solar PV, and battery, because CCGT with imported LNG becomes cheaper relative to other fossil resources, especially as the planning horizon approaches 2045, due to the externality costs. In terms of vRE, additional solar and battery expansions were built in the *High Demand* sensitivity because of the limited techno-economic potential of wind in the model. The additional capacity in the *High Demand* sensitivity relative to the *Base Case* is shown in Table 5-3.

Table 5-3: Additional capacity in *High Demand* sensitivity (relative to *Base Case*)

Additional Capacity (MW)						
Expansion Category	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Battery	0	396	357	-387	308	2939
Solar	0	4163	4163	7453	7813	10975
Offshore Wind	0	0	0	675	643	2022
Onshore Wind	0	818	1218	908	728	728
Hydro	0	0	0	0	0	0
Biomass + other RE	0	300	300	0	433	433
LNG (ICE+SCGT)	0	472	1976	3650	3995	3395
Import LNG	0	0	1308	4606	6236	9637
Domestic Gas	0	0	0	0	0	0
Import Coal	0	0	1209	616	3013	3013
Domestic Coal	0	0	0	0	0	0

In the *HVDC* sensitivity, where the HVDC line is "force built" in 2030, the model chooses to build more offshore wind capacity (29 GW by 2045 vs. 22 GW in the *Base Case*) instead of new imported coal plants (31 GW by 2045 vs. 33 GW in the *Base Case*). This indicates that building new transmission transfer capability between the South-Central region and the North region could reduce new coal builds in the future. The *HVDC* sensitivity also has the highest amount of batteries expansion (12.9 GW by 2045, 37% more than the *Base Case*). The additional batteries provide flexibility for the increased vRE penetration (38.5% in 2045 vs 34.8% in the *Base Case*).

In the *\$30 CO_2* sensitivity, higher emissions price assumption of US\$30/ton of CO_2 has major impacts on the capacity expansion of the Vietnam power system. New coal builds and coal generation becomes too expensive, and only a small amount of new imported coal expansion was built in this sensitivity. From 2030-2040, about 2,100 MW of import coal capacity was built in the *\$30 CO_2* sensitivity compared to 11,400 MW in the *Base Case*. From 2040-2045, no new coal was built by the *\$30 CO_2* sensitivity, whereas an additional 6,600 MW of imported coal was built in this time period in the *Base Case* scenario.

To make up for the shortfall in imported coal, the model builds more wind, imported LNG power plants, and twice as much solar capacity relative to the *Base Case* (88 GW vs. 41 GW in 2045). In addition, nuclear power plants are built, starting in the early 2030s, with 4.4 GW of nuclear plants being built by 2045, indicating that US\$30/ton is sufficient to incentivize nuclear builds in Vietnam, despite its high capital costs. It is possible that if more nuclear capacity is allowed, more will be built in the 2040's as well—however, there could be a tradeoff with vRE capacity, especially if cost of wind and solar are lower. More analysis is needed to test the conditions under which nuclear power plants can be built economically in Vietnam.

When the price of CO_2 is pushed to US\$100/ton, fossil resources expansions are further reduced. Imported coal capacity in 2045 was slightly lowered to 22.3 GW and imported LNG-based capacity decreased to 31 GW. On the other hand, solar and battery expansions are much larger in the *\$100 CO_2* sensitivity relative to the *\$30 CO_2* sensitivity (127.2 GW of solar and 17GW of batteries in 2045 vs. 88GW and 10.9 GW, respectively).

Figure 5-5: Built Capacity (top) and Installed Capacity (bottom) for cost-reduction sensitivities

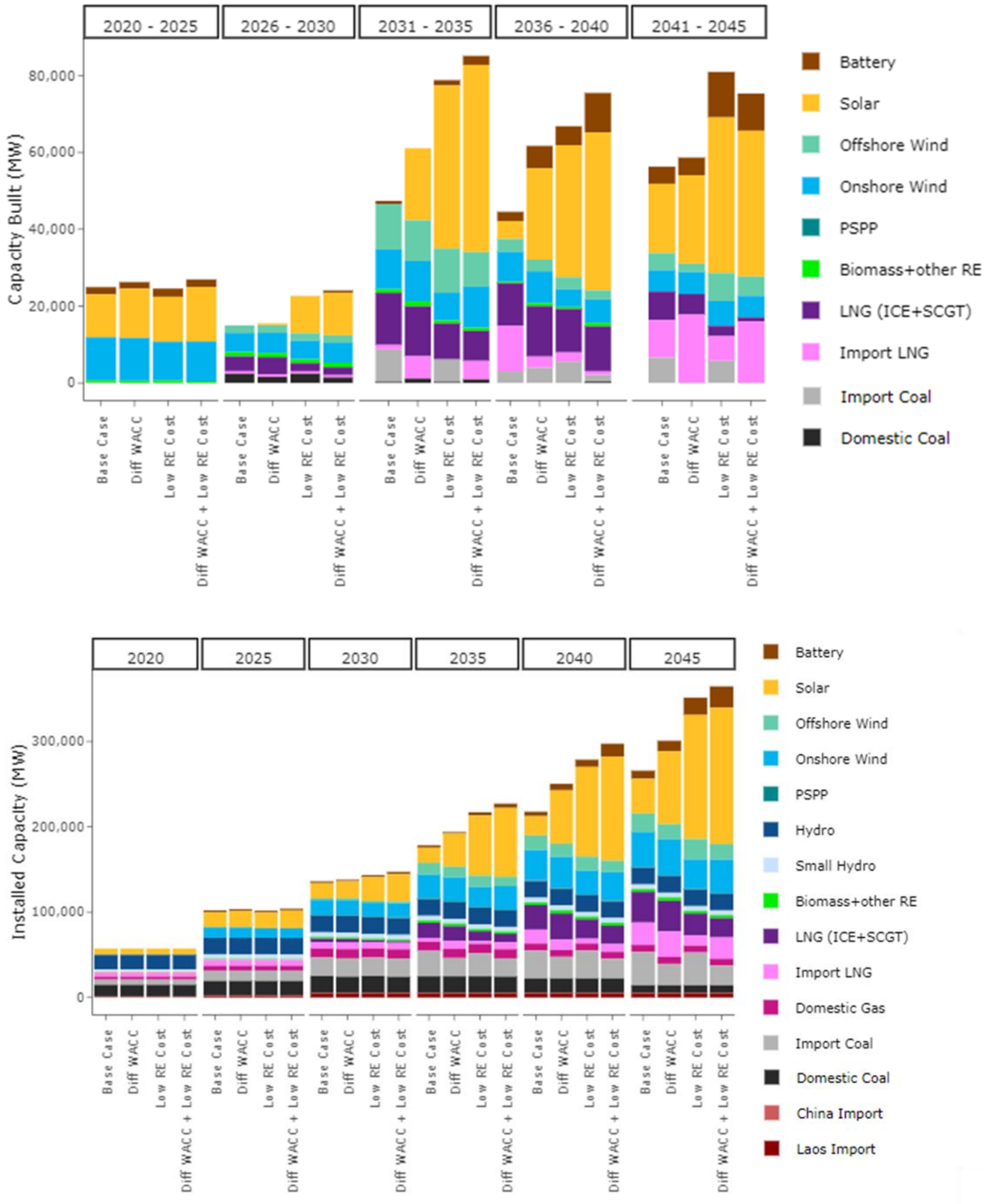


Figure 5-5 shows the built capacity and installed capacity for the cost-reduction sensitivities in five-year increments. All of these sensitivities have much higher solar capacity compared to the *Base Case* due to the lower cost of solar PV plants, either by lowering the WACC or when CAPEX is reduced. The lower cost of solar in the cost-reduction sensitivities also allows for building solar PV much earlier in the planning horizon, with major expansions after 2030 instead of the expansions in the 2040s as shown for the *Base Case*. Because renewable resources do not carry a fuel or emission cost, the WACC reductions for RE increases renewables accordingly as shown in the installed capacity.

The 3% lower financing costs for LNG relative to coal in the *Diff-WACC* sensitivity, makes LNG the dominant fossil expansion, despite its higher fuel cost. In general, higher risk for coal financing (regardless of lower RE costs) makes building new coal capacity more difficult, with coal capacity being replaced by solar and batteries and LNG-based CCGT.

5.1.2 REGIONAL INTERFACES

Figure 5-6 shows the interface expansion in the *Base Case* scenario. The expansions in the first ten years are mainly in the North to North-Central interface due to its smaller transfer capacity and the growing need for energy in the North region. In the next 15 years, from 2030 onwards, there is much larger expansion in the interfaces connecting the Central regions to the South. This is because of the concentration of generation expansion in the Central regions (wind and solar) and the large load growth in the South region.

Figure 5-7 shows the interface expansion for the policy-based scenarios. The expansions in all of these scenarios (except the *BAU*) follow a pattern of expansion similar to the *Base Case*. The *BAU* scenario has similar amount of total interface expansion compares to others but the expansion is shifted out to 2040s.

Figure 5-8 shows the interface expansion for the *No Externality Cost* sensitivity case compared to the *Base Case*. With more coal generators located near the load centers and less vRE, the *No Externality Cost* sensitivity requires less South-Central-South interface expansion.

Figure 5-9 shows the interface expansion for the operational sensitivities in 5-year increments. Overall, the interface expansions in these sensitivities (except for the *HVDC* sensitivity) are similar to the *Base Case*. In the *HVDC* sensitivity, the added transfer capability between the North region and South-Central region allows for the North region to utilize more vRE energy from the South-Central region and reduce its import from the North Central region. Therefore, the *HVDC* sensitivity has a lower amount of expansion in the North to North-Central and North-Central to Mid-Central interfaces.

Figure 5-10 shows the aggregate interface expansion for the cost-reduction sensitivities in 5-year increments. These sensitivities show a larger amount of expansion in the Highland interfaces compared to the *Base Case*, as most of the available solar resources are located in the Highland region.

Figure 5-6: Interface Expansion for the Base Case scenario

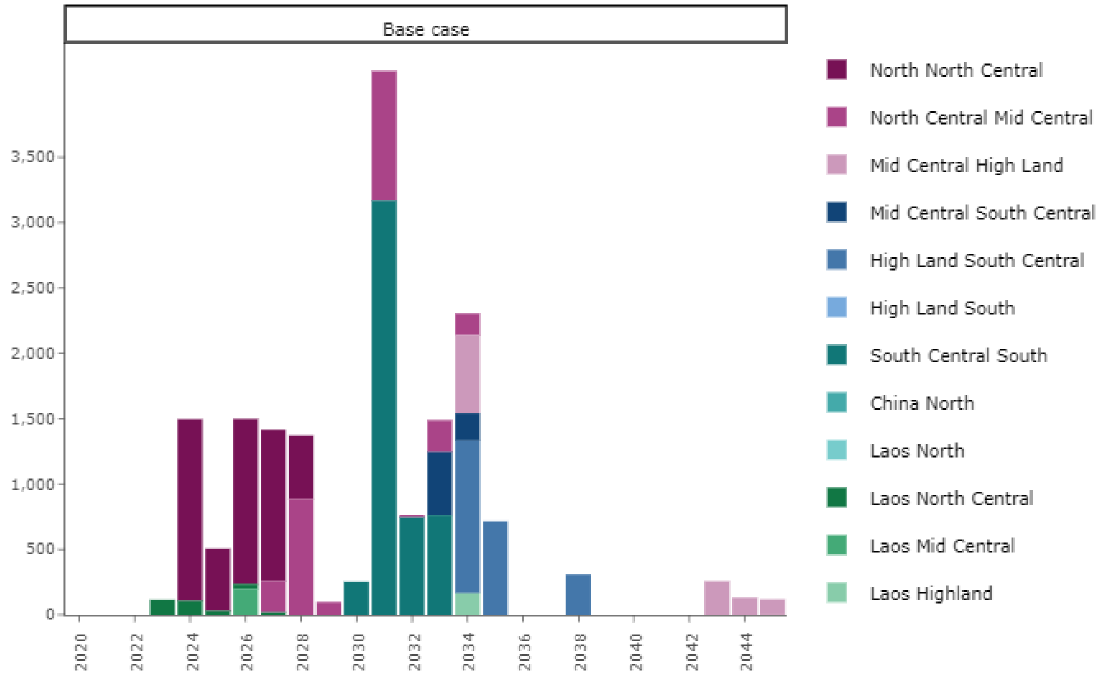


Figure 5-7: Interface Expansion for the Policy-based scenarios

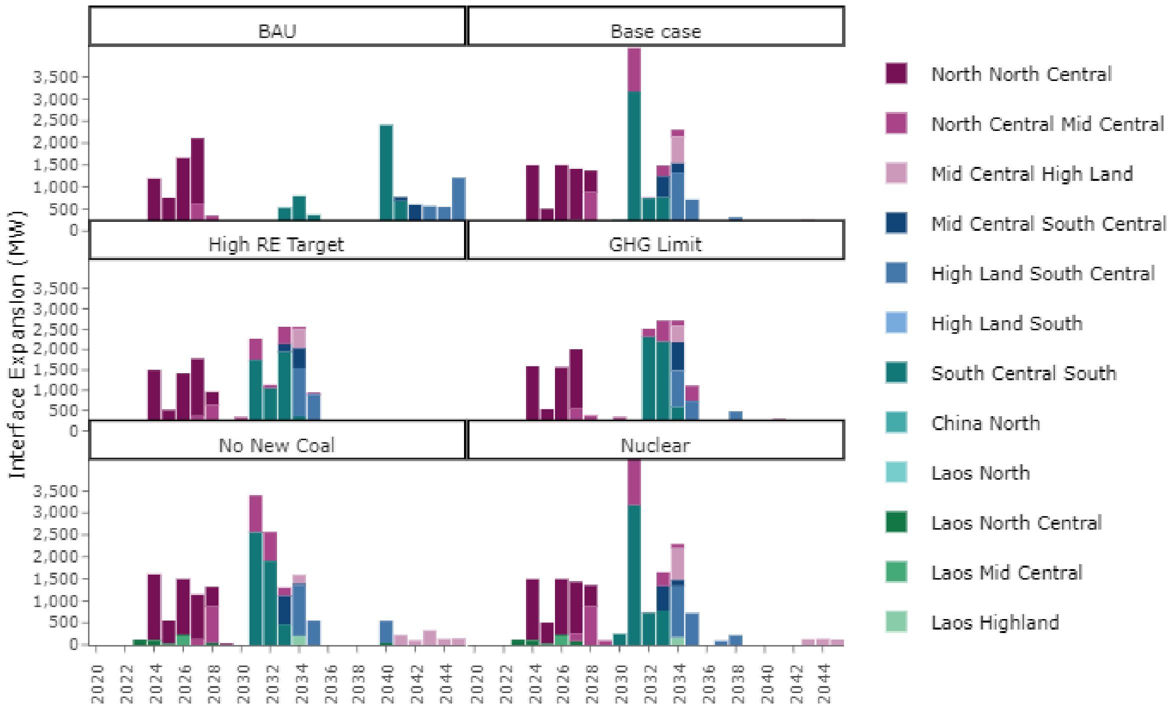


Figure 5-8: Interface Expansion for the No Externality Cost sensitivity

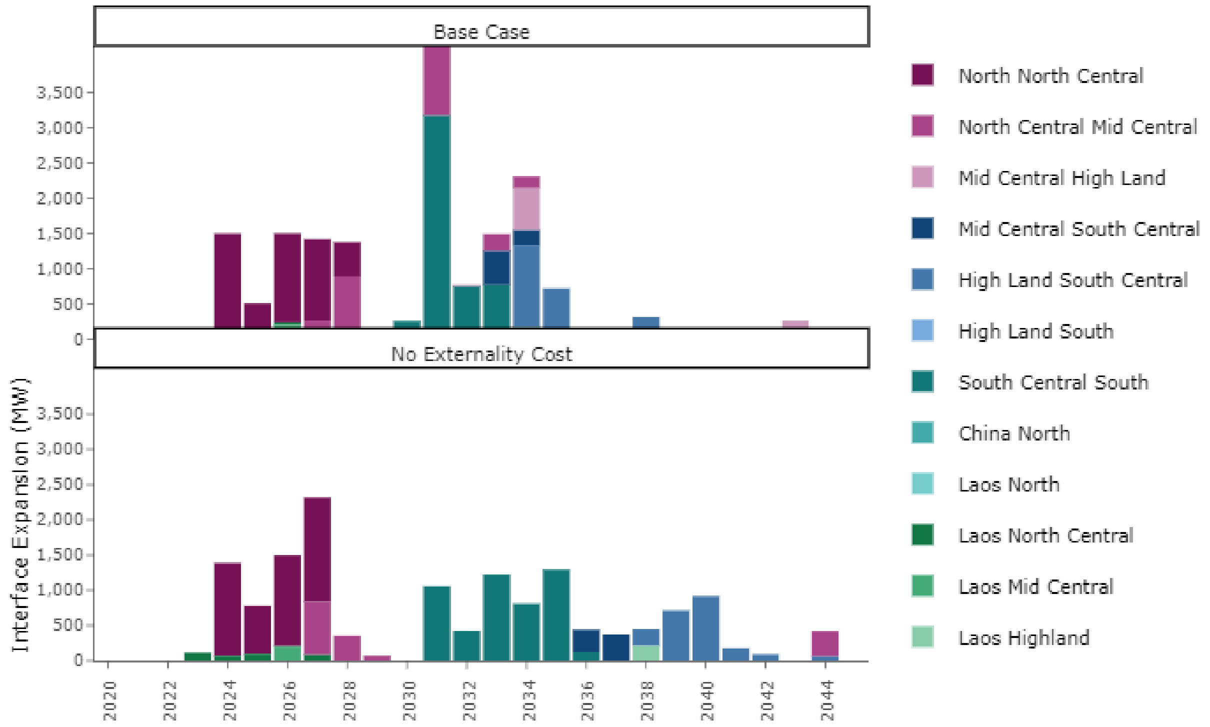


Figure 5-9: Interface Expansion for the Operational sensitivities

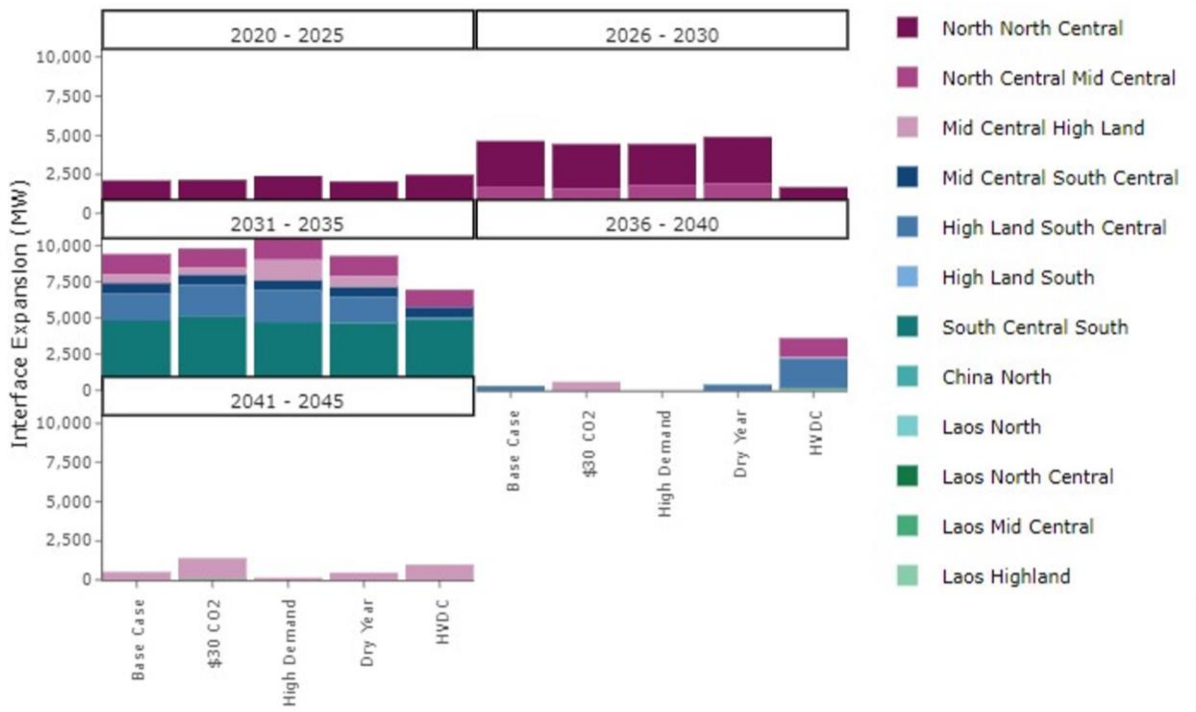
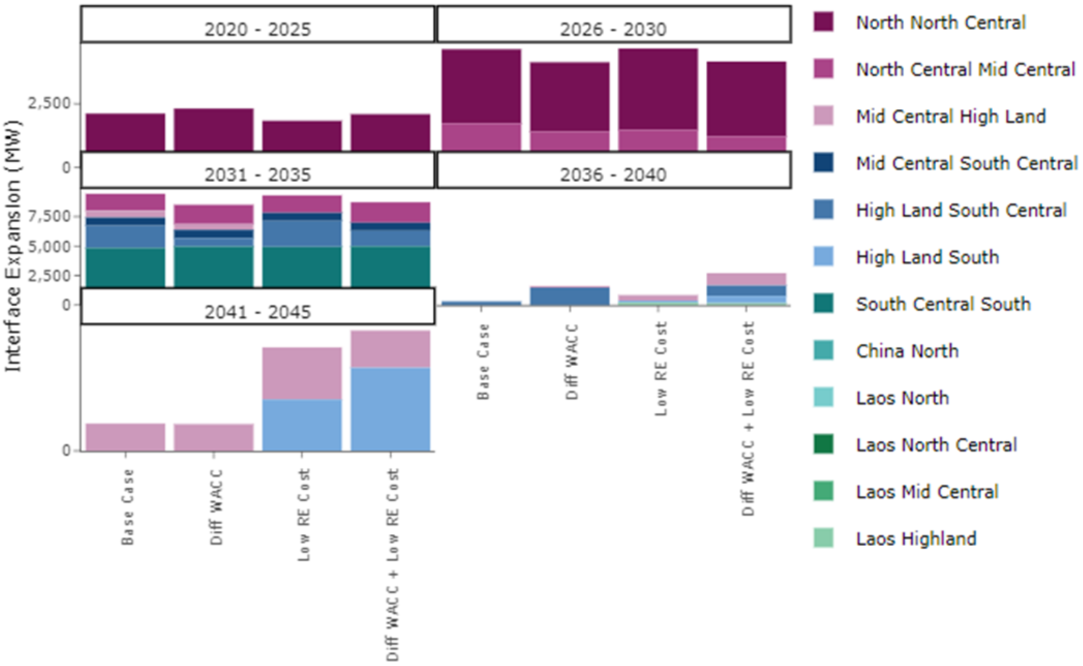


Figure 5-10: Interface Expansion for the Cost-Reduction sensitivities



5.2 ENERGY GENERATION RESULTS

Figure 5-11f711 shows the generation by resource type in five-year increments for the *Base Case* scenario. Generation from renewables (including hydro) increases from 35% in 2020 to more than 38% in 2030 and 45% in 2045, exceeding the RE target. Due to its low capacity-factor, with 15% of installed capacity, solar generators contribute to only about 6% of total energy produced in 2045. In 2045, there are 9.5 GW of batteries installed on the system, but they only discharge 375 GWh of energy. This shows that batteries are being built to provide flexibility for the system and build out of batteries could be reduced if there is more flexibility in the thermal fleet (including greater operational flexibility in coal and gas generators). Similarly, LNG-based ICE and SCGT generators are being used to provide flexibility, as they have much lower energy generation than LNG-based CCGT despite having comparable amount of installed capacity.

Figure 5-12 shows the generation by resource type in five-year increments for the policy-based scenarios. The generation pattern follows that of the installed capacity. The *High RE Target* and *No New Coal* scenarios have the most generation from solar. Wind generation across all of the policy-based scenarios are similar, except for the *BAU*—the BAU generation is dominated by imported coal generation, given that the *BAU* scenario has no externality costs applied on emissions.

Figure 5-13 shows the fuel consumption for the *Base Case*. In 2045, coal is still the most consumed fuel and accounts for 55.7% of total fuel consumption by energy. LNG is not present in 2020 but by 2045 makes up 34.3% of total fuel consumption. Domestic fuels make up 73.1% of total fuel usage in 2020 but are reduced to 20.4% by 2045.

Figure 5-11: Generation for the Base Case scenario

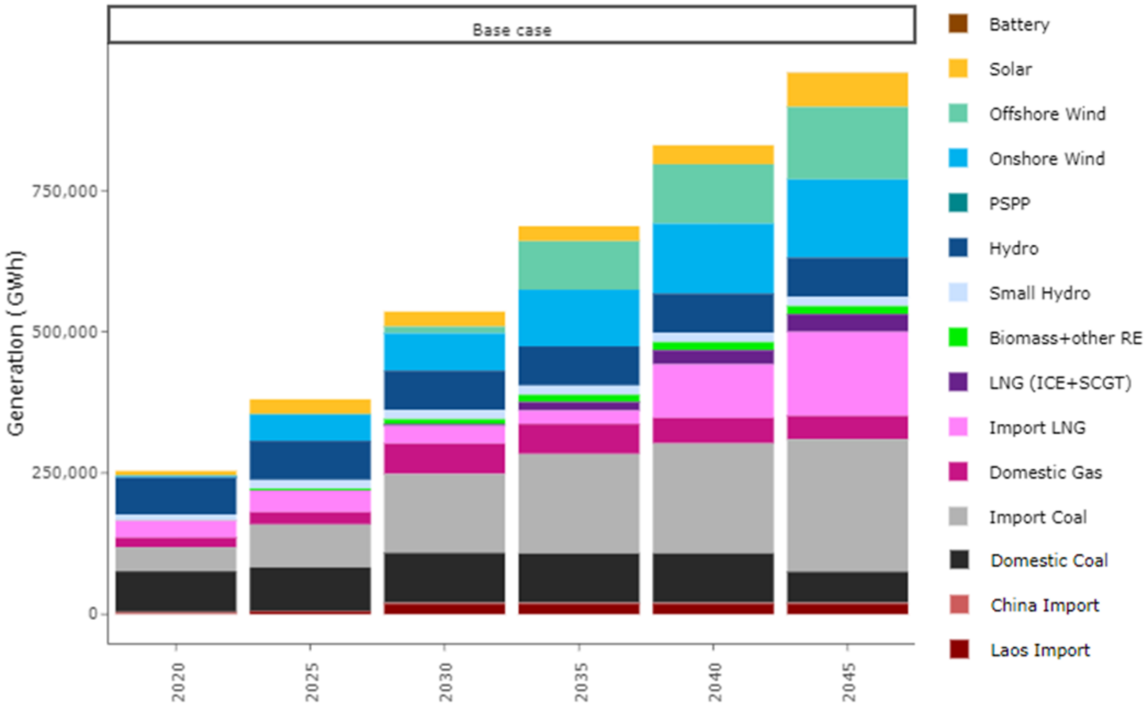


Figure 5-12: Generation in five-year increments for the policy-based scenarios

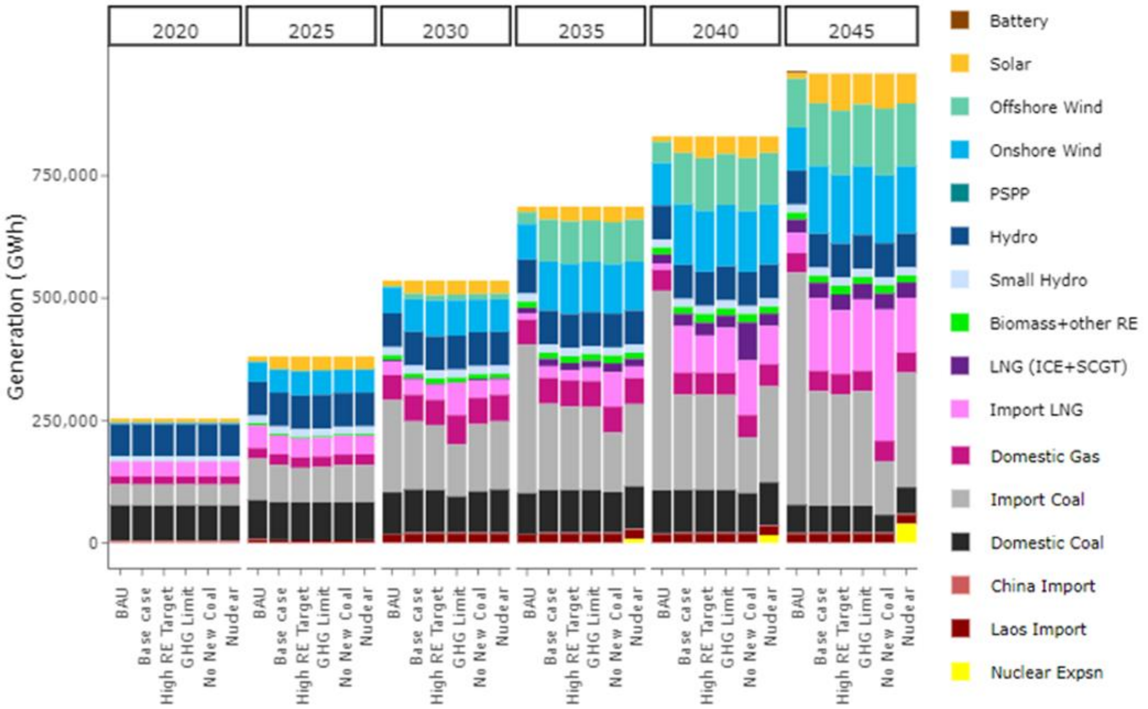


Figure 5-13: Fuel Consumption for the Base Case scenario

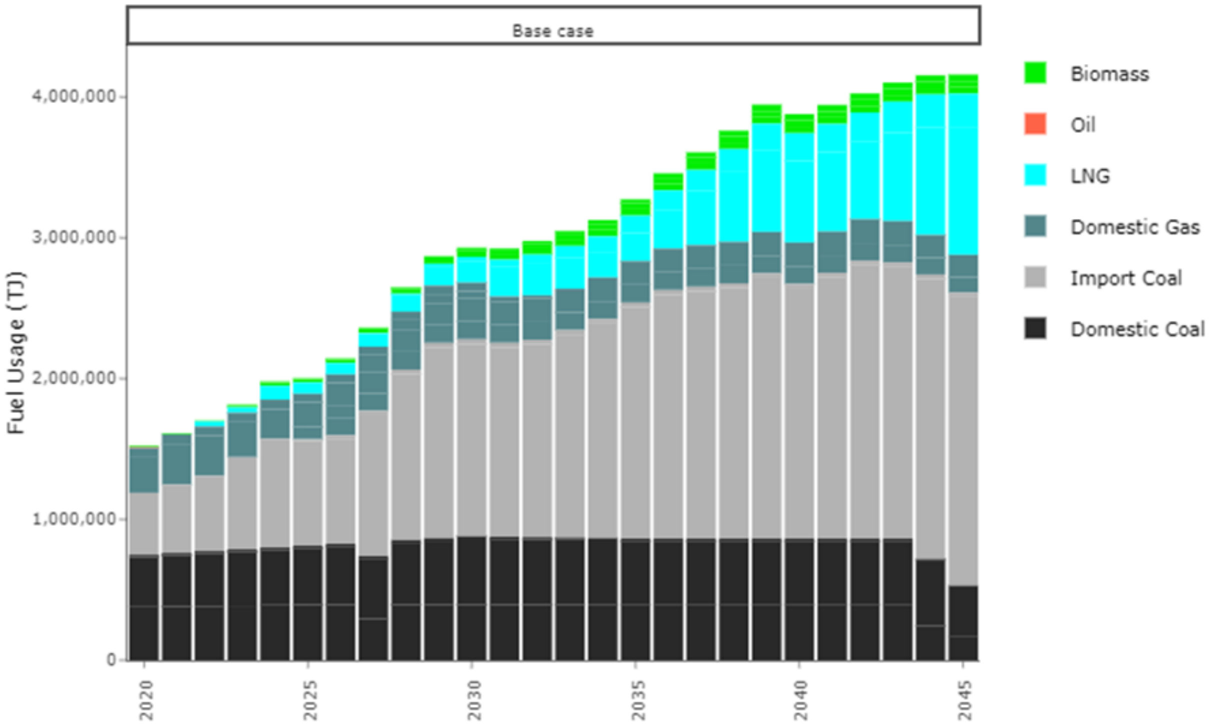


Figure 5-14 shows the fuel consumption for the policy-based scenarios. Fuel use mix diverge after 2030 for different scenarios, when all the firm-builds (shown in Table 4-2) have come online. The *BAU* scenario uses the most fuel with 85% of total fuel consumed based on coal. For the other scenarios, LNG usage increases heavily from 2030 to 2045. The highest amount of LNG consumption is in the *No New Coal* scenario with LNG being nearly 50% of total fuel consumption. In the *Nuclear* scenario, the primary reduction is from LNG being used for CCGT, indicating that LNG is the marginal fuel, given its high cost. In general, all scenarios rely heavily on imported fuels by 2045.

Figure 5-14: Fuel Consumption in five-year increments for the policy-based scenarios

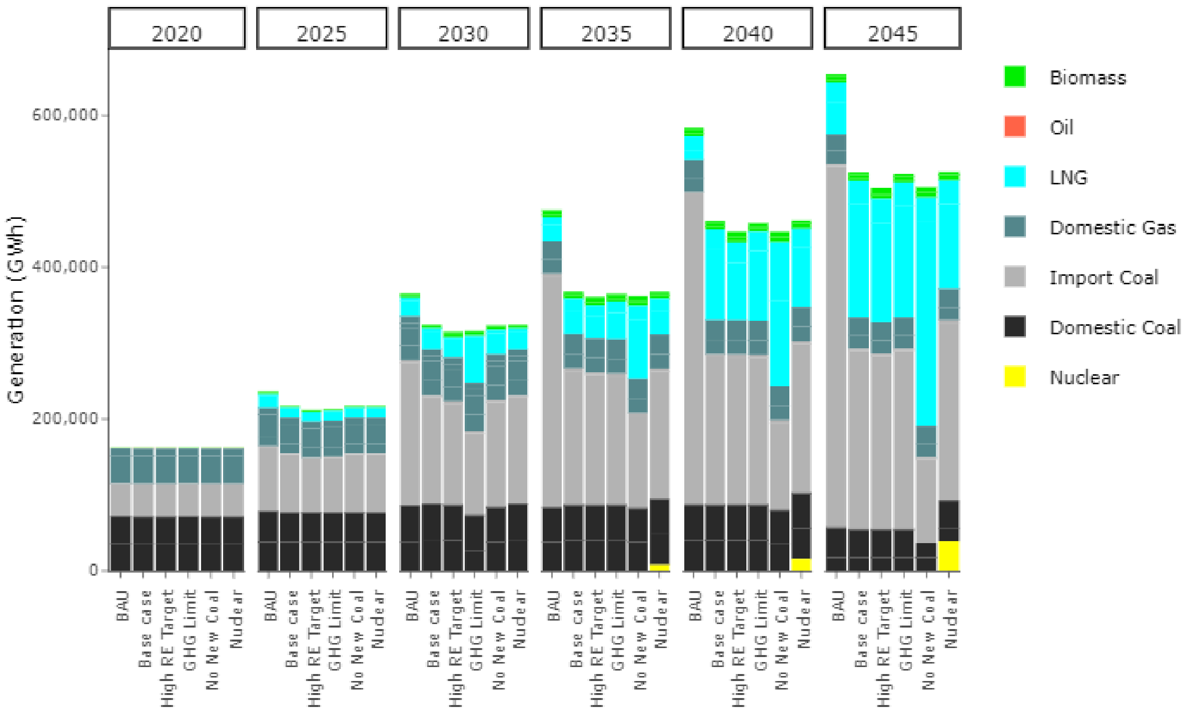


Figure 5-15 shows the aggregate battery discharge every five years for the policy-based scenarios. Because battery is a storage resource, generation from the battery is the energy discharged from the storage of electricity. The battery efficiency assumption is the same for all scenarios and sensitivities in this report. During the first 15 years, battery utilization is low across all scenarios; however, the utilization of batteries increases as more RE resources are built toward the end of the planning horizon. The *BAU* scenario, despite having the lowest amount of renewables in all scenarios, has the highest utilization of batteries. Energy discharge from battery in the *BAU* scenario is almost four times the next highest scenario (*No New Coal scenario)*. This shows that without increasing the flexibility of the existing and new thermal fleet, batteries are needed to provide the necessary flexibility for the Vietnam power system. Notwithstanding this finding, additional studies are needed to further evaluate the battery use across the different scenarios and sensitivities, in a PCM analysis.

Figure 5-15: Aggregate battery discharge in five-year increments for policy-based scenarios

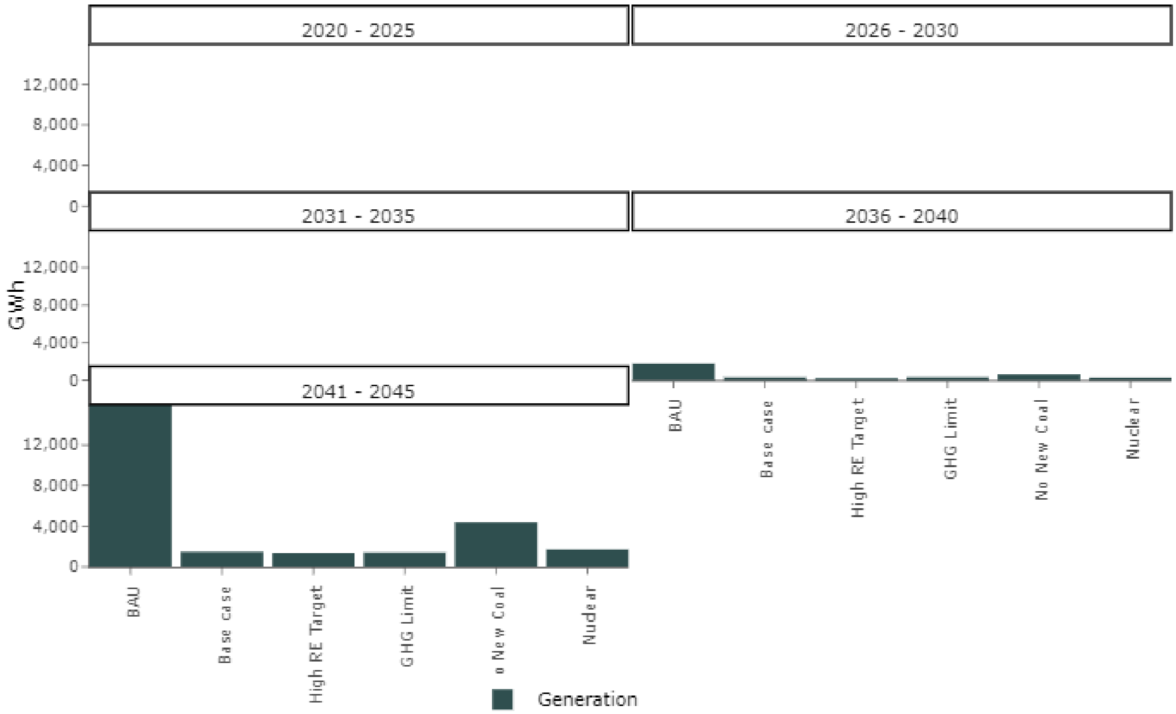


Figure 5-16 shows the generation for the *No Externality Cost* sensitivity in five-year increments. Unsurprisingly, the main difference between the *Base Case* and this sensitivity is the coal generation, as more generation comes from coal in place of import LNG and vRE.

Figure 5-17f717 shows the generation for the operational sensitivities in five-year increments. Generation is consistent with the build patterns for these sensitivities. The *High Demand* sensitivity has the highest total generation to satisfy the higher load. In 2030, the *High Demand* sensitivity produced 6.2% more energy compared to the *Base Case;* and by 2045, the difference increases to 9.1%.

The *\$30 CO_2* sensitivity has the lowest amount of coal generation along with the highest amount of generation from imported LNG, wind and solar. This indicates that a relatively high carbon price can reduce generation from both new and existing coal plants in Vietnam; however, LNG consumption rises to offset most of the reduced coal generation, relative to the *Base Case*. Because of its large solar capacity, the *\$30 CO_2* sensitivity also has the highest utilization of batteries, as shown in Figure 5-18.

The differences in generation between the operational sensitivities are also reflected in the fuel consumption (Figure 5-19). The *\$30 CO_2* sensitivity has the lowest total fuel consumption while the *High Demand* sensitivity has the highest. The *Dry Year* sensitivity fuel consumption is similar to that of the *Base Case* except in 2020. Because 2020 is the base year with no expansion, the *Dry Year* sensitivity uses fuel oil generators to replace the limited hydro generation.

Figure 5-16: Generation in five-year increments for the No Externality Cost sensitivity

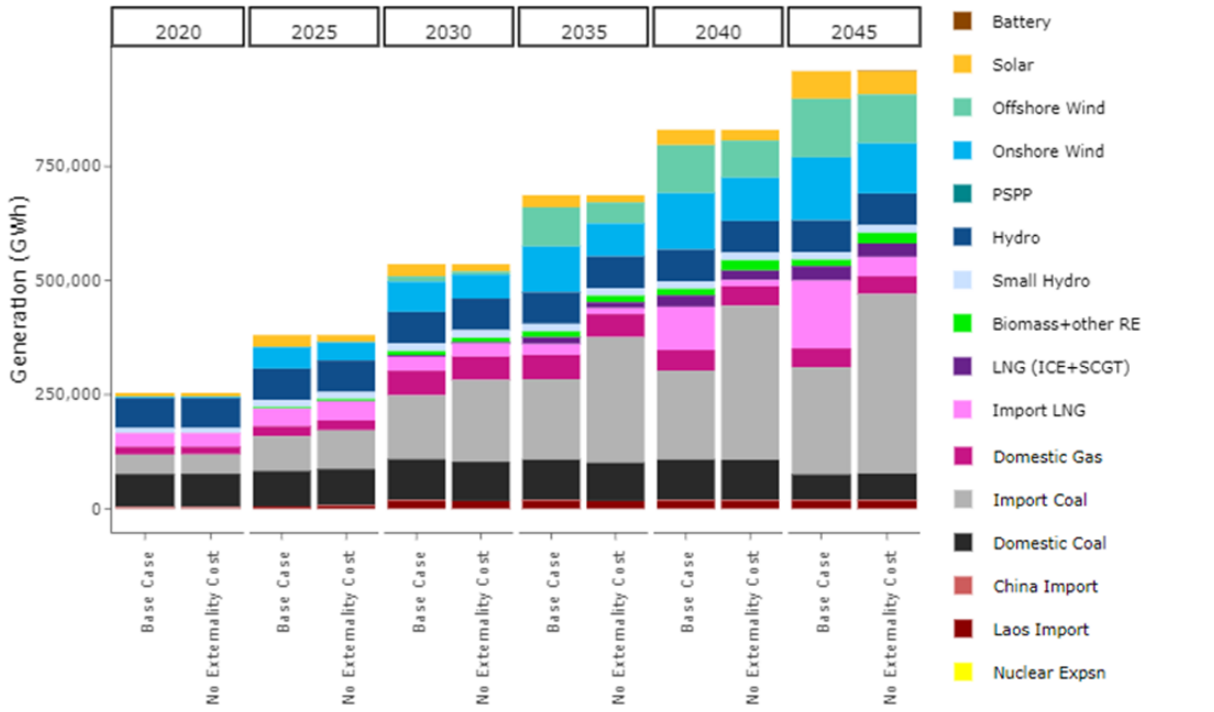


Figure 5-17: Generation in five-year increments for Operational sensitivities

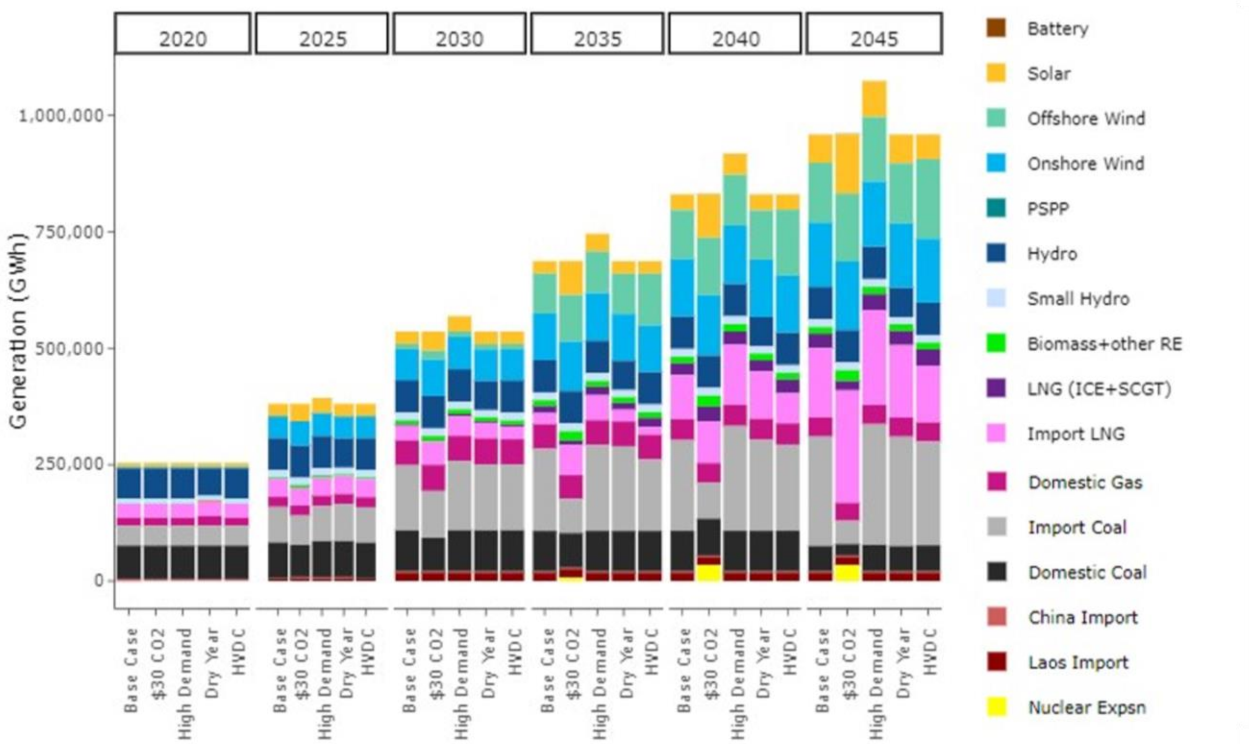


Figure 5-18: Battery generation in five-year increments for Operational sensitivities

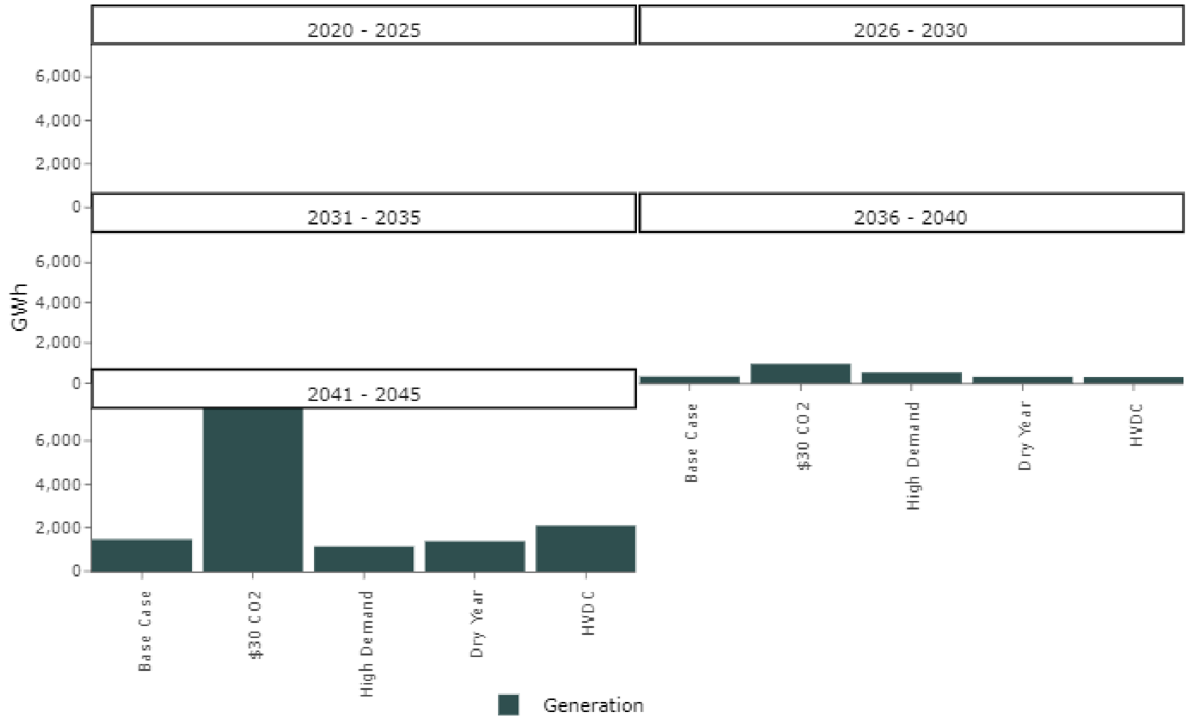


Figure 5-19: Fuel consumption in five-year increments for Operational sensitivities

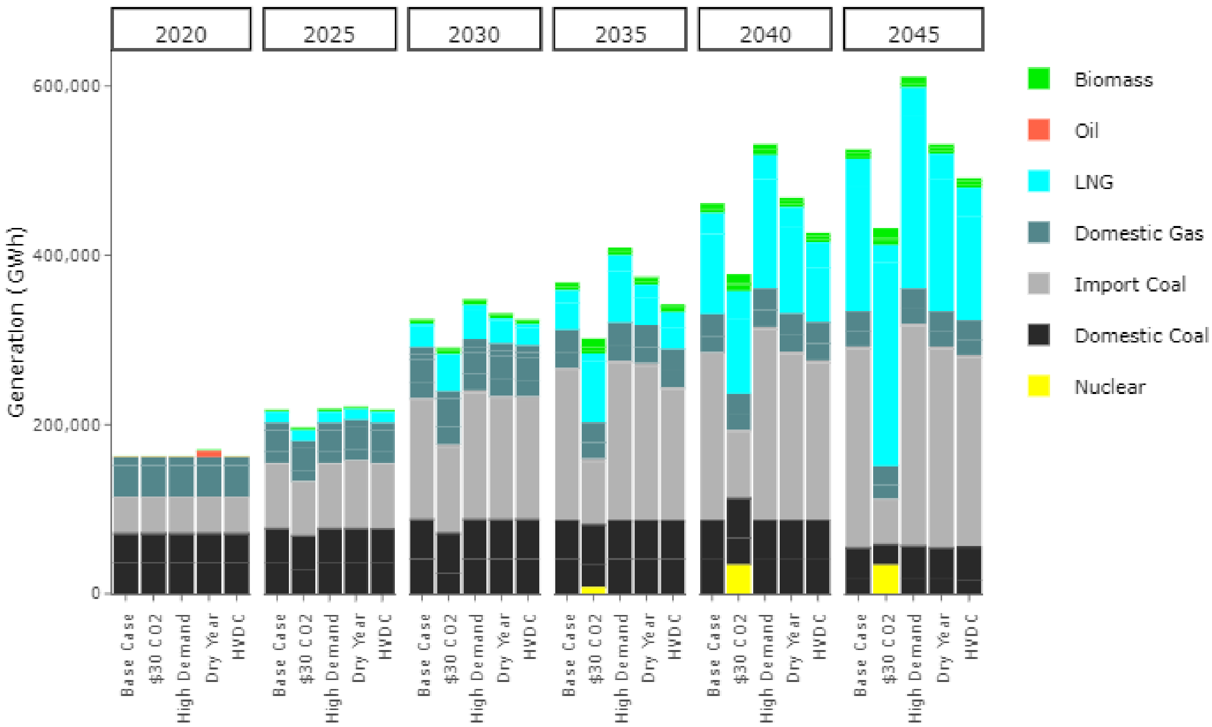


Figure 5-20 shows the generation for the cost-reduction sensitivities in five-year increments. In the *Diff WACC+Low RE Cost* sensitivity, despite much larger solar capacity compared to the *Base Case*, the generation from solar is only equal to that of wind (due to relatively high wind capacity factors). In general, fuel consumption gradually decreases, as the share of renewable resources increases (Figure 5-21).

Battery utilization in the sensitivities with low RE cost are much higher compared to the *Base Case* (Figure 5-22), indicating the value of investing in batteries as vRE capacity increases in the system. In the *Diff WACC+Low RE Cost* sensitivity, battery utilization in the 2040's is more than ten times that of the *Base Case*. The operational and cost-reduction sensitivities show that at a lower level of vRE penetration, battery utilization is low and can be replaced by increasing flexibility in the thermal fleet.

However, as vRE penetration rises beyond 25% of installed capacity, batteries become an important resource in the operation of the power grid. More studies will be needed to fully assess the benefits of batteries on system with high penetration of vRE.

Figure 5-20: Generation in five-year increments for Cost-Reduction sensitivities

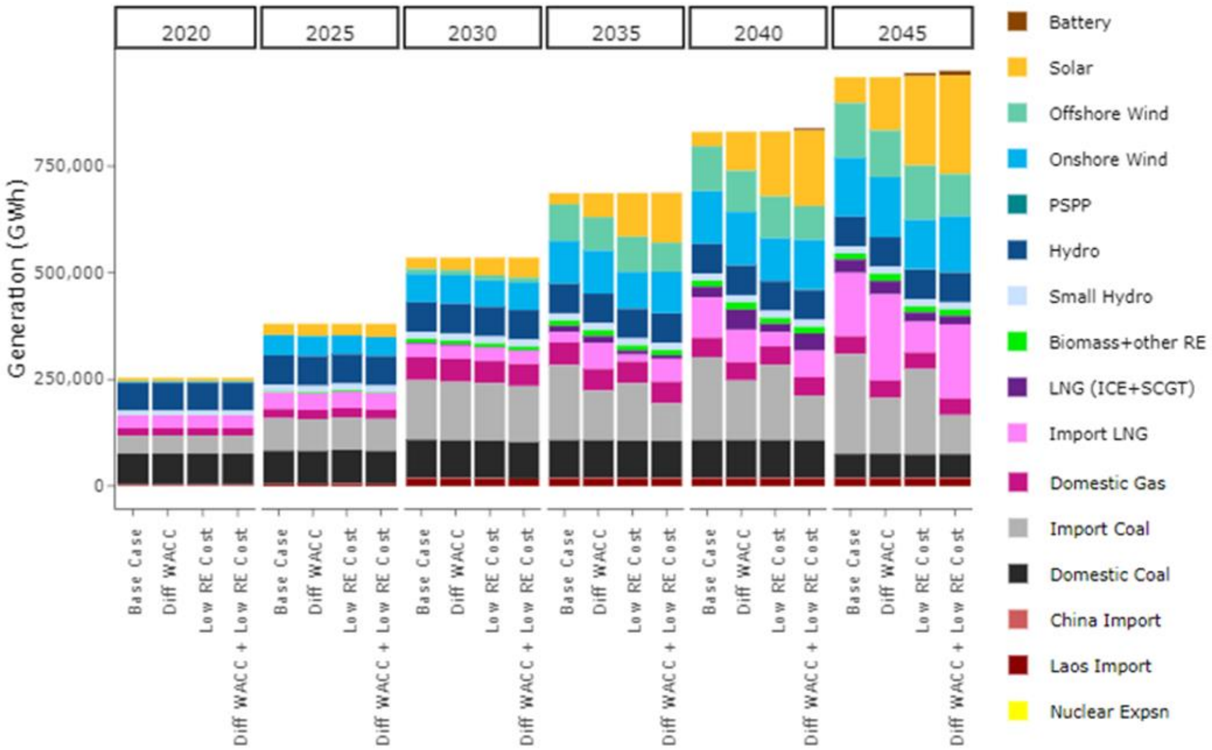


Figure 5-21: Fuel consumption in five-year increments for Cost-Reduction sensitivities

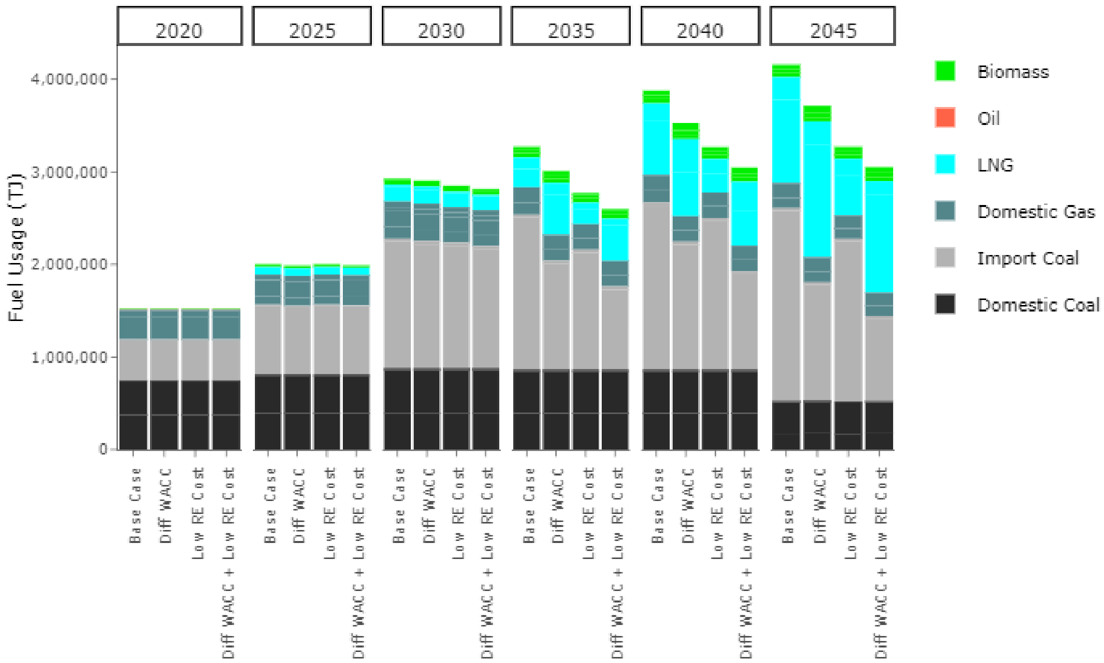
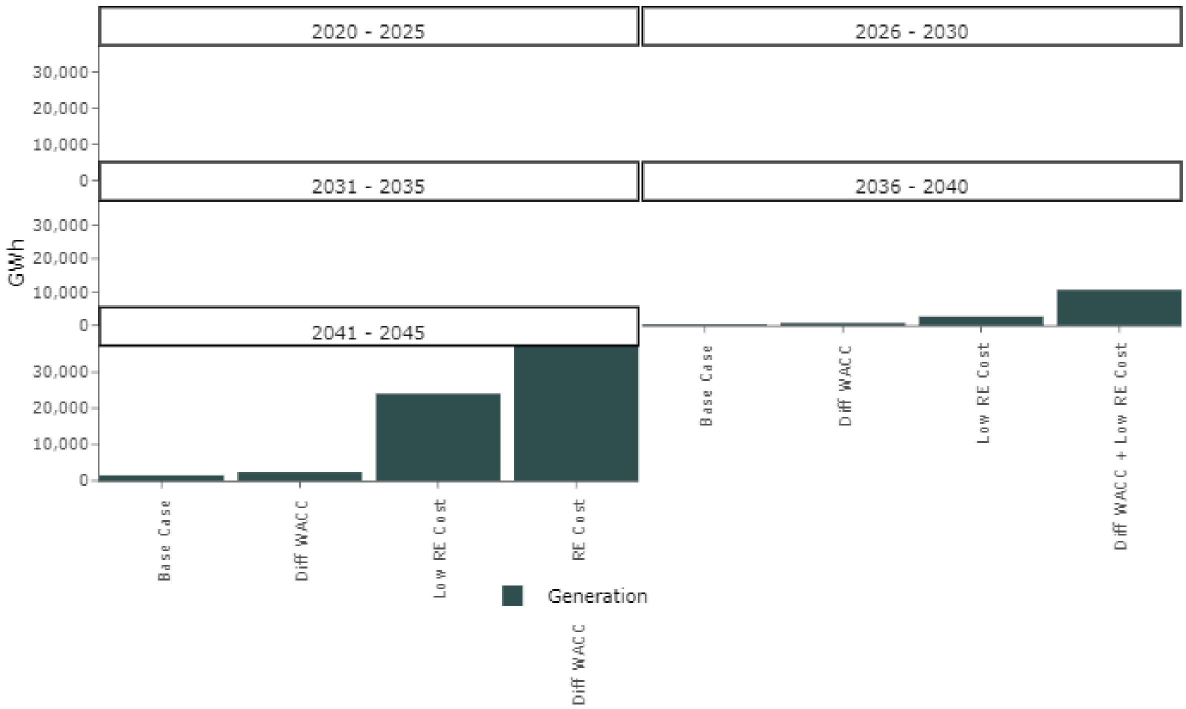


Figure 5-22: Battery generation in five-year increments for cost-reduction sensitivities



5.3 INTER-REGIONAL FLOW RESULTS

Figure 5-23 shows the net interchange by region for the *Base Case* scenario. The North and South regions are net import regions while the Central regions are net exporters. The North region's import peaks in 2031 and decreases toward the end of the horizon due to more generators being built in the North. The growth in export from the South Central region coincides with the growth in imports to the South region. This shows that an increasing fraction of the demand in the South region is being served by the South-to-South Central interface.

Figure 5-23: Net Interchange by Region for the Base Case scenario

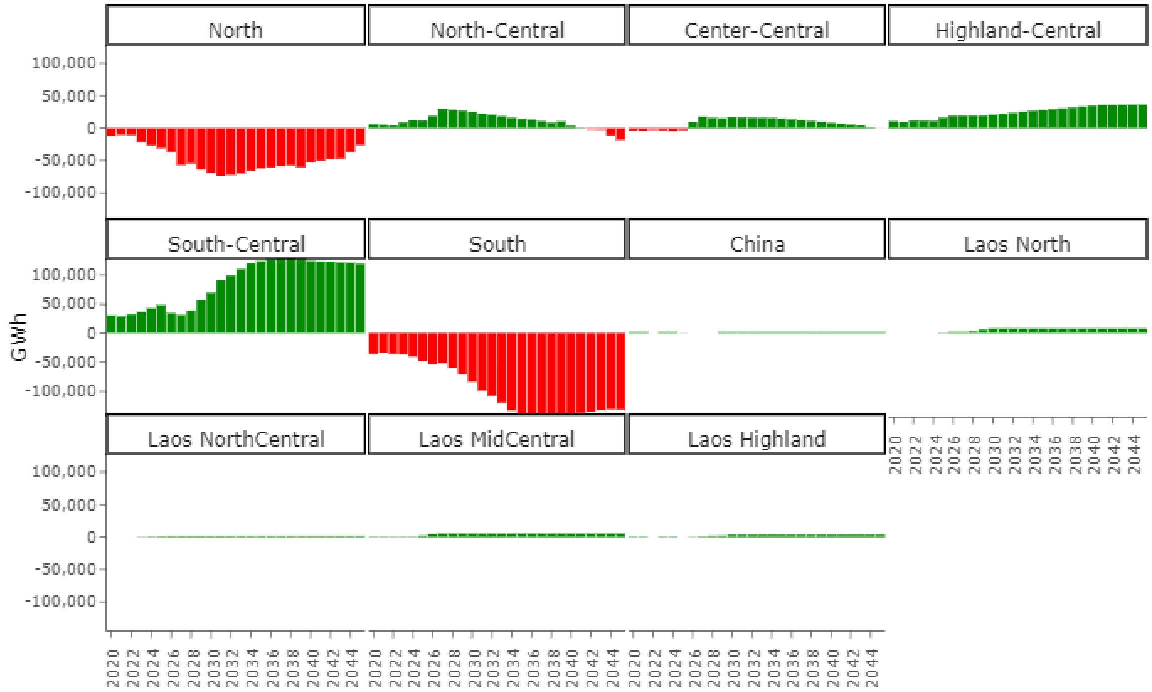


Figure 5-24 shows the net interchange by region for the policy-based scenarios. The interchange trend is consistent across all scenarios—similar to the *Base Case*. Energy moves from the Central regions where there is excess generation to the load centers in the North and South regions. The *BAU* scenario has more generation in the South, and thus has a more gradual ramp up in energy import for this region. The North region in the *BAU* scenario has lower generation capacity and thus higher net import compared to the *Base Case*.

Similar to the policy-based scenarios, interchange patterns in most sensitivities do not deviate from the *Base Case*. Excess energy from the Central regions is transferred to the load centers in the North and the South. However, the interchange pattern in the *HVDC* sensitivity differs significantly from the *Base Case*. With the additional 6 GW in transfer capability from the South-Central region to the North region, the total energy export from the South-Central region exceeds 150,000 GWh, which is 50% higher than the *Base Case*. With access to cheap vRE energy from the South-Central region, the North maintains high import level until 2040 instead of tapering off after 2030, as in the *Base Case*. The net interchange by region for the *HVDC* sensitivity is shown in Figure 5-25.

Figure 5-24: Net Interchange by Region for the Policy-based scenarios

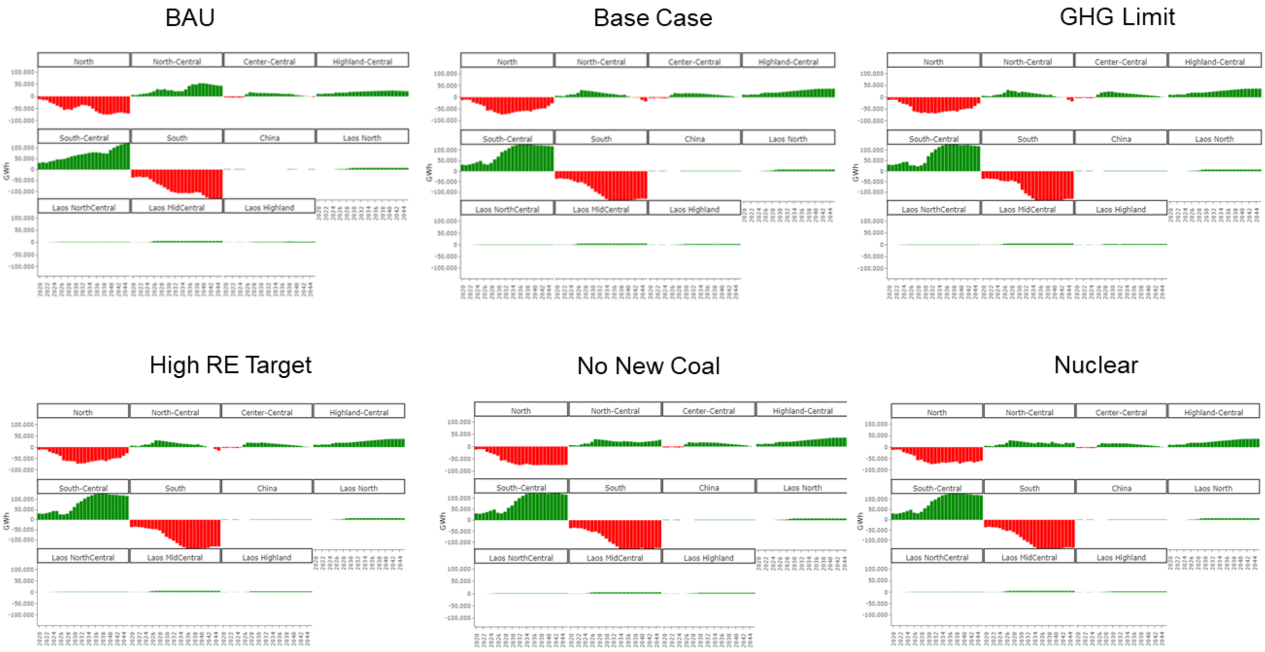
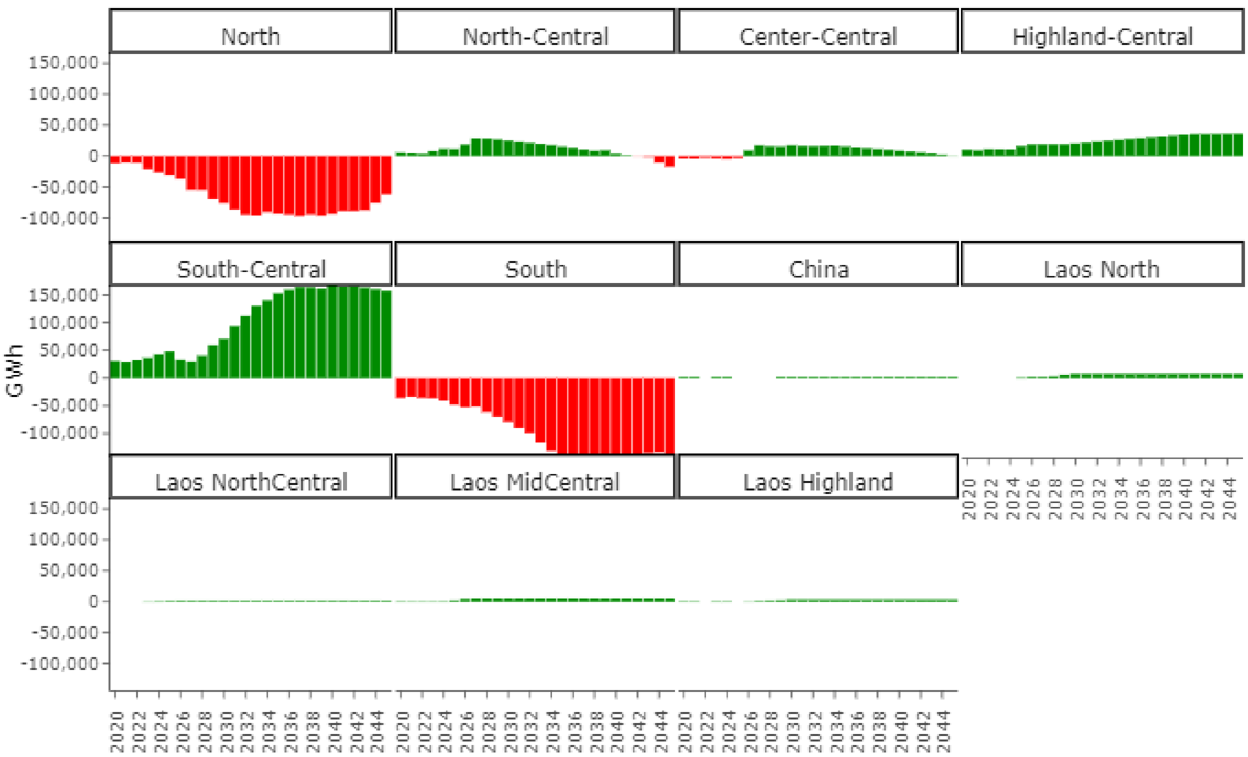


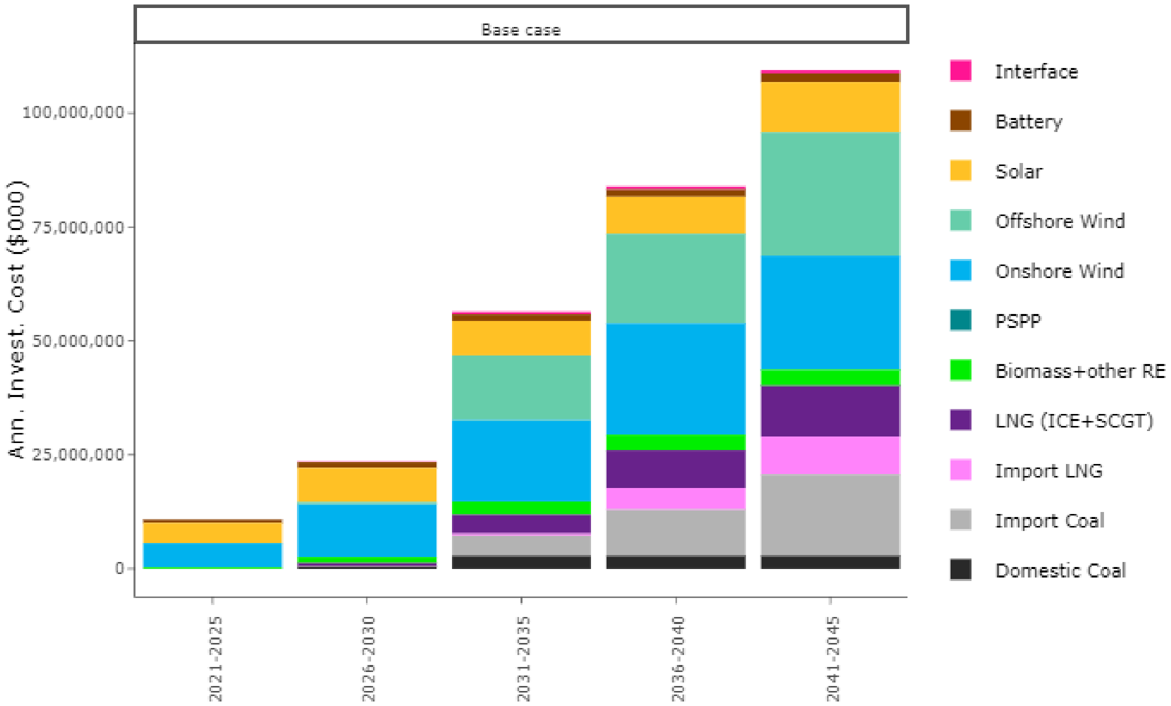
Figure 5-25: Net Interchange by Region for the HVDC sensitivity



5.4 COST COMPARISON RESULTS

Figure 5-26 shows the annualized investment cost for the *Base Case* scenario. Given that solar expansion in the *Base Case* scenario is concentrated in the first and the last five years, the cost contribution of solar to the annualized investment cost is flat throughout the planning horizon. Onshore and offshore wind contribute the most to the annualized investment cost over time. The cost of interface expansion is relatively small compared to the cost of generation capacity expansion.

Figure 5-26: Annualized Investment Costs for the Base Case scenario



The total system cost for the *Base Case* is shown in Figure 5-27. The total system cost includes the operational costs (production + externality) and the annualized investment costs. Despite the greater investments in vRE resources, the total system cost for the Base Case is dominated by the fuel and emissions costs of fossil resources. Total system costs from coal (import and domestic) resources make up 43% of the cost in 2020 and 35% of the total system costs in 2045. System costs of LNG-based power plants also increase over time. Operational (production + emission) costs in Figure 5-28 shows slower growth in two five-year periods (after 2030 and after 2040) due to the large increases in renewable resources in these periods.

Figure 5-27: Total System Cost for the Base Case scenario

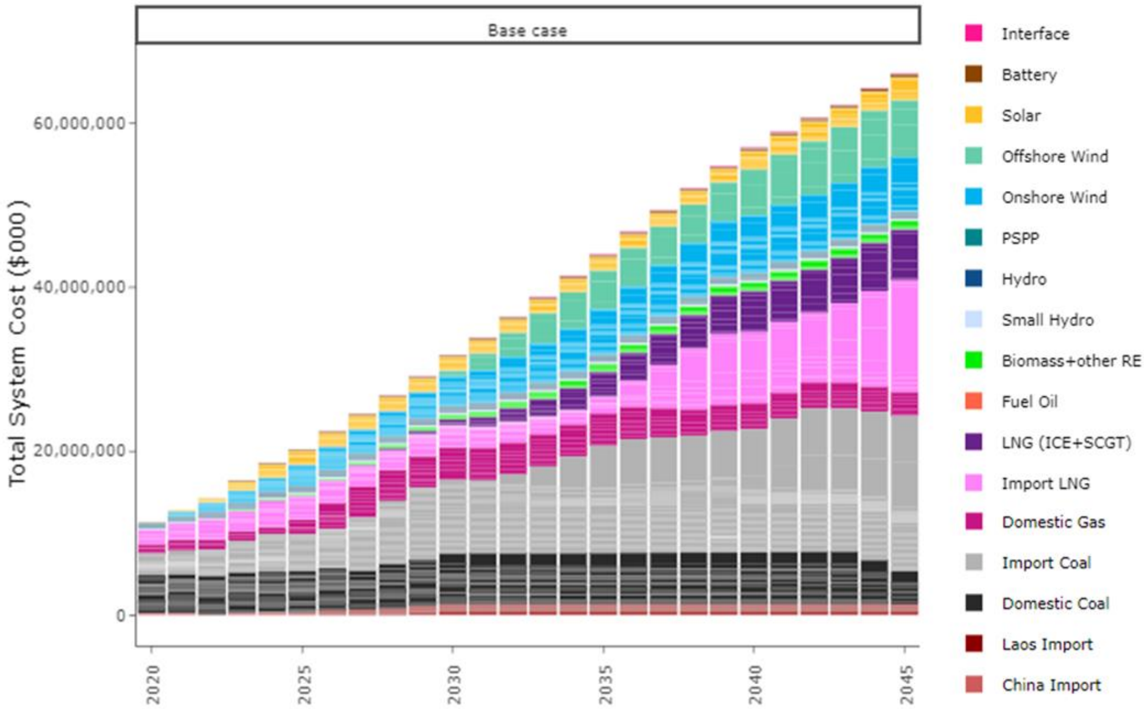


Figure 5-28: Operational (production + externality) for the Base Case scenario

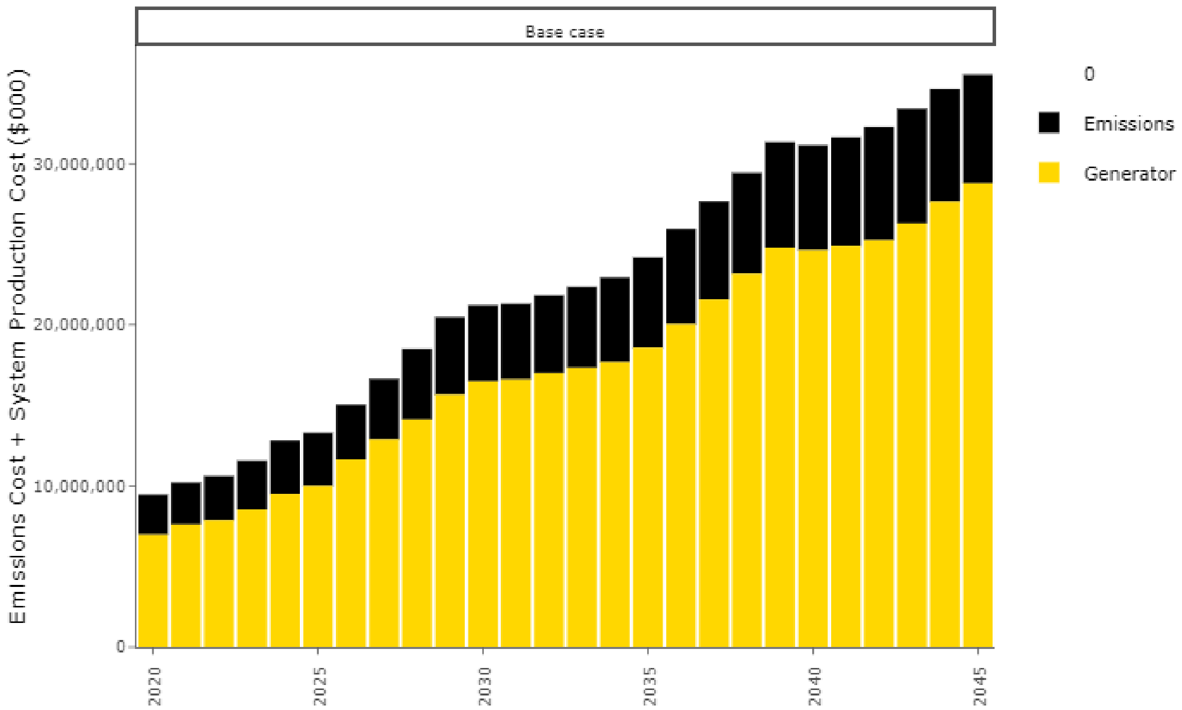
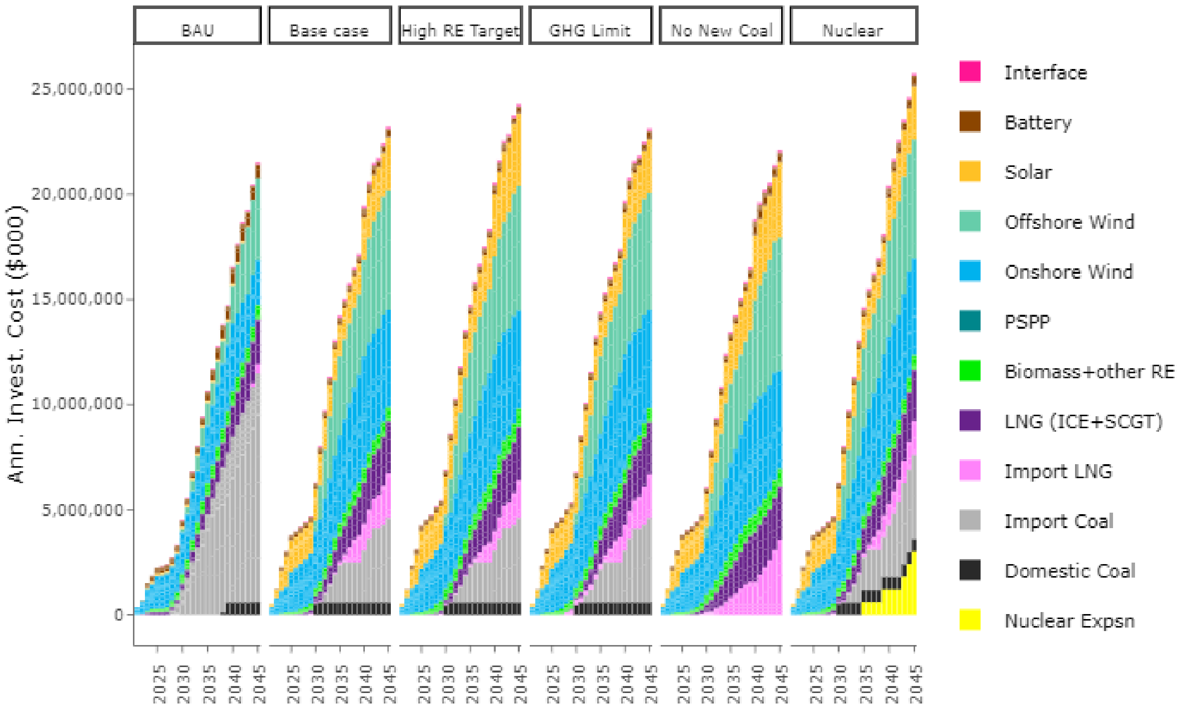


Figure 5-29 shows the annualized investment costs for the policy-based scenarios. Except for the *BAU* scenario, wind expansion accounts for most of the cost in all scenarios throughout the planning horizon. The *Nuclear* scenario has the highest annualized investment cost compared to other scenarios, due to the high cost of nuclear plants, despite having lower solar PV expansion.

Figure 5-29: Annualized Investment Costs for the policy-based scenarios



The total system costs for the policy-based scenarios are shown in Figure 5-30. The *BAU* scenario has the lowest total cost because of its reliance on coal generators—by not having any RE targets or externality costs. On the other hand, the cost of nuclear makes the *Nuclear* scenario the most expensive. For all scenarios, interface expansion is a minor part of the total system cost.

Figure 5-31 shows the operational (production + emission) costs for the policy-based scenarios. The *No New Coal* scenario has the highest production cost because of the higher level of LNG usage. The *GHG Target* scenario shows a spike in emission costs from 2027 to 2031, because in these years, the model is constrained by the CO_2 limit and the shadow price of CO_2 emissions increases from $4/ton to a high of $39/ton in 2030 to ensure that the emission limit is met. Smaller increases in the shadow price of CO_2 also occur in 2020 and 2024 in this scenario.

Figure 5-30: Total System Cost for the policy-based scenarios

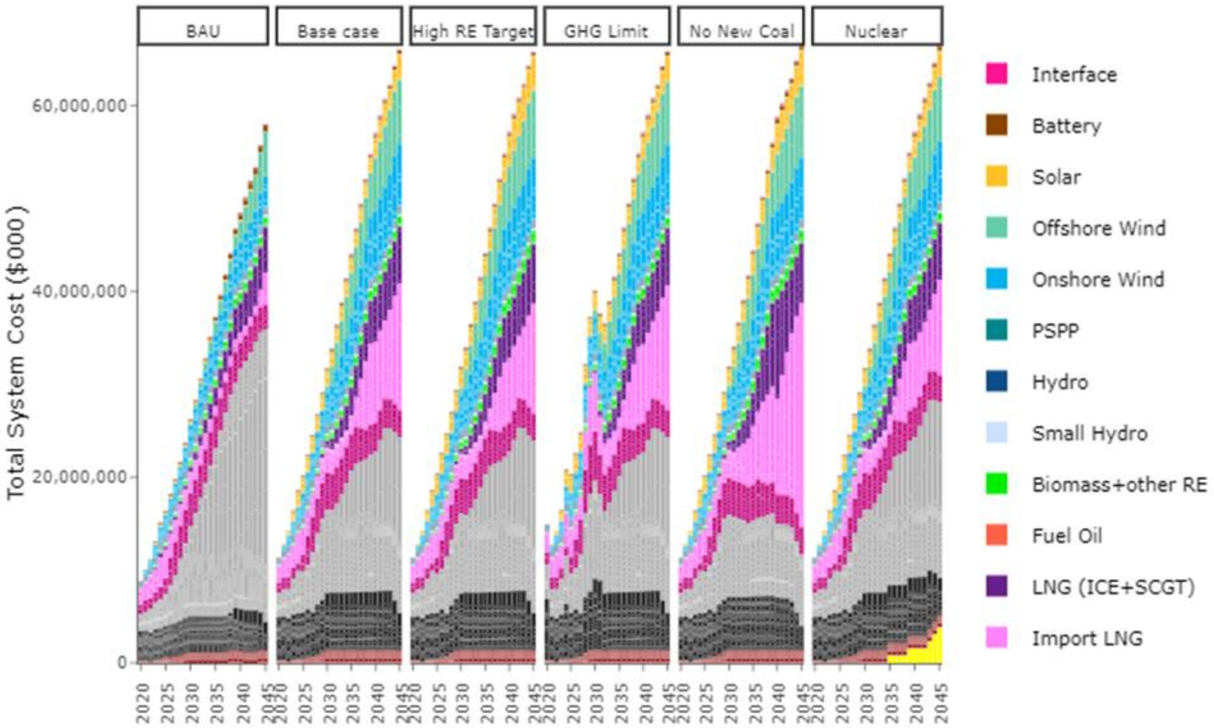


Figure 5-31: Operational (production + externality) costs for the policy-based scenarios

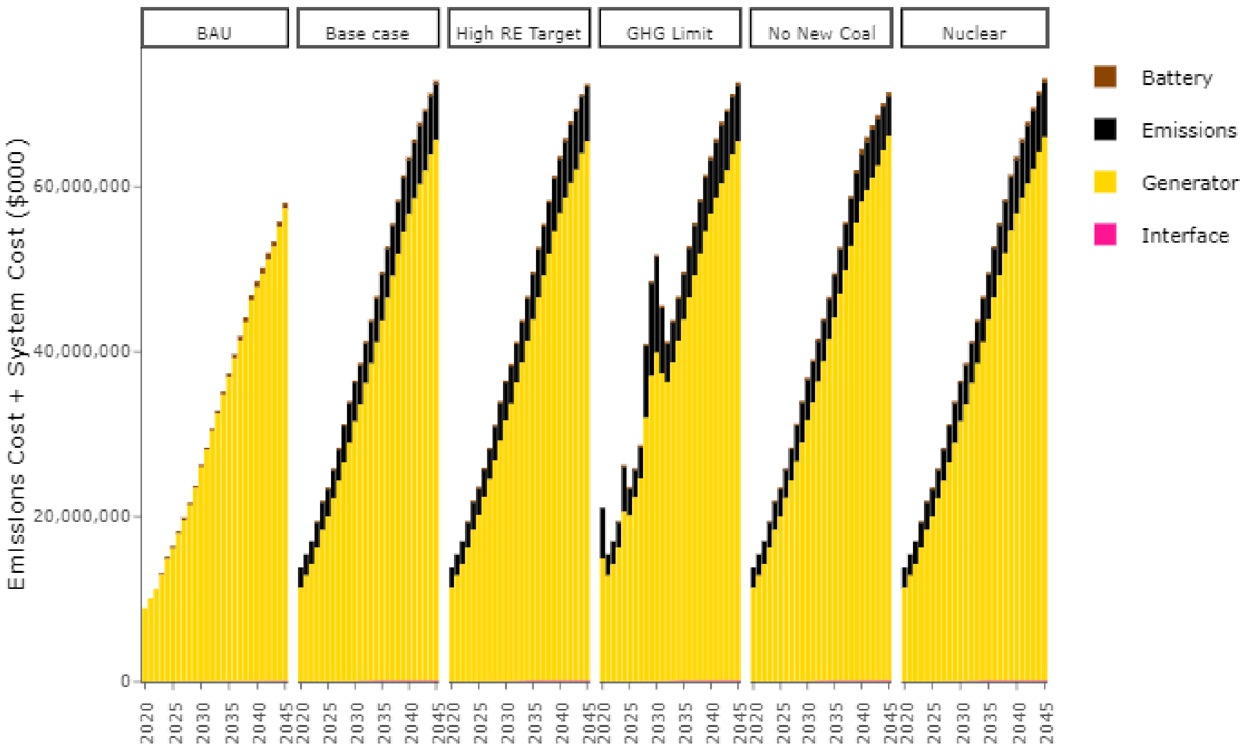


Figure 5-32 shows the annualized investment costs between the *Base Case* and the *No Externality Cost* sensitivity. The *No Externality Cost* sensitivity has higher investment cost than the *Base Case*, despite having less vRE resources. Although it saves money on the investment costs of vRE, the greater expansion of coal generation drives the overall investment cost. The expansion in coal generation is justified because coal has much lower fuel cost and lower production cost due to no emissions cost in this sensitivity (see Figure 5-33 for the total system costs).

Figure 5-32: Annualized Investment Costs for No Externality Cost sensitivity

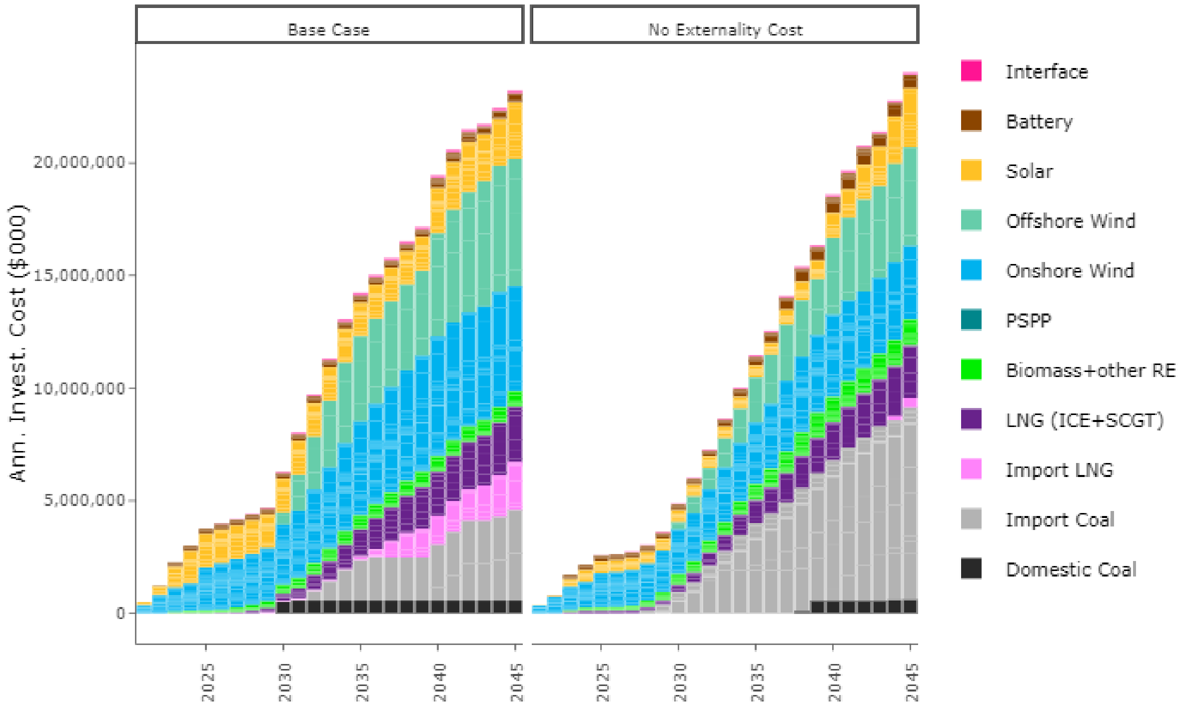


Figure 5-33: Operational (production + externality) for No Externality Cost sensitivity

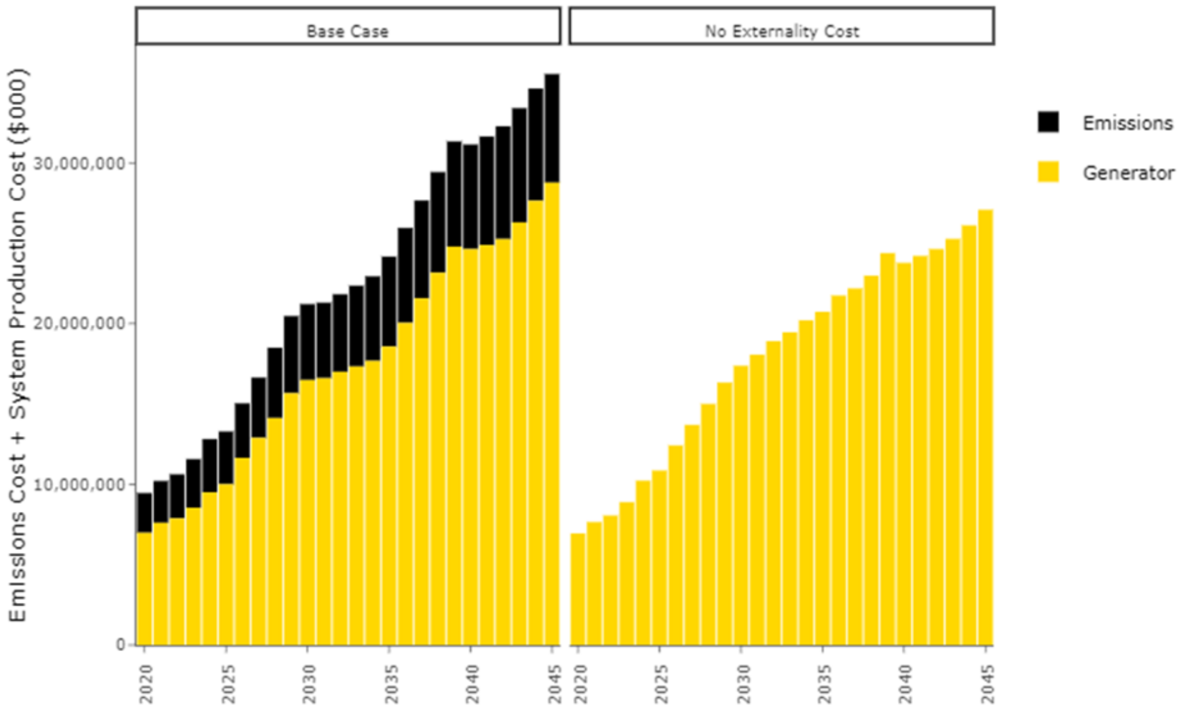
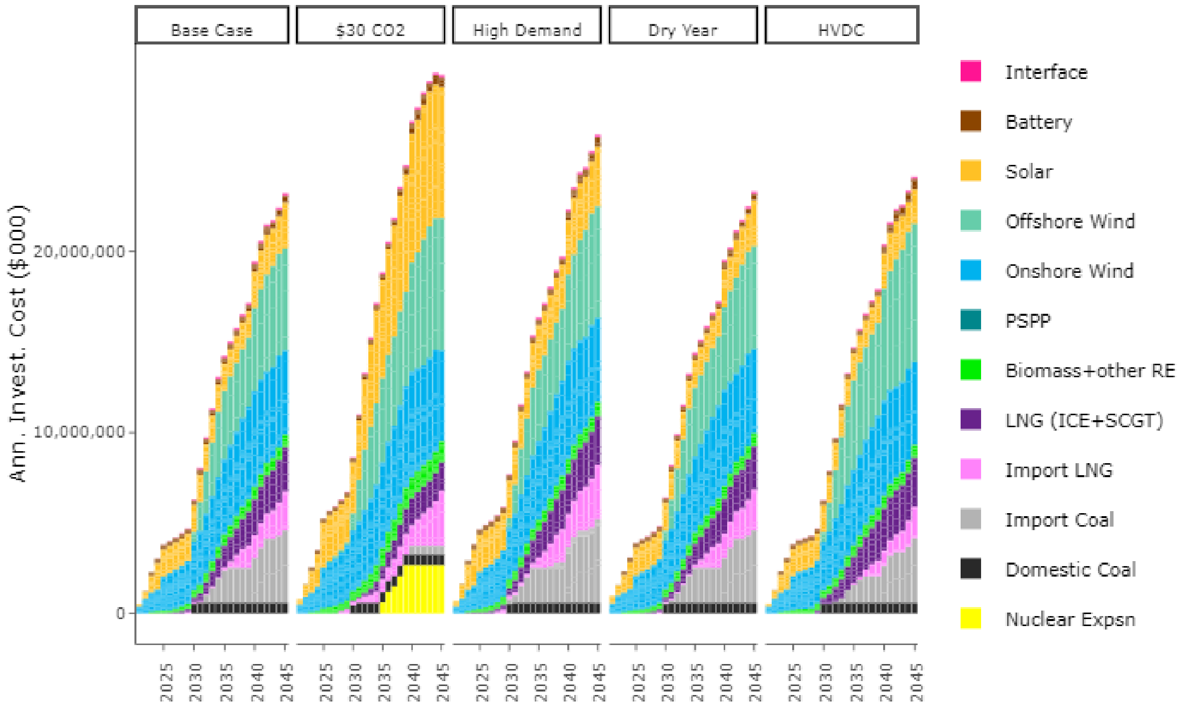


Figure 5-34 shows the annualized investment cost for the operational sensitivities. Due to the high cost of nuclear and vRE, the *\$30 CO_2* sensitivity has the highest investment cost. In the extreme case where the price of CO_2 is increased to \$100/ton, the investment cost is 15% higher than that of the *\$30 CO_2* sensitivity.

Because the *HVDC* connection is “forced” in the model for the corresponding sensitivity, the cost of the *HVDC* investment is not reflected in Figure 5-34. The annualized investment cost of the “forced” *HVDC* line is \$390 million per year starting from 2030. With this added cost, the *HVDC* sensitivity is higher than the *Base Case*. Even though the cost of interface expansion in the *HVDC* sensitivity is about four times that of interface expansion cost from in the *Base Case*, it is still only a small part of the annualized investment cost.

Figure 5-34: Annualized Investment Costs for Operational sensitivities



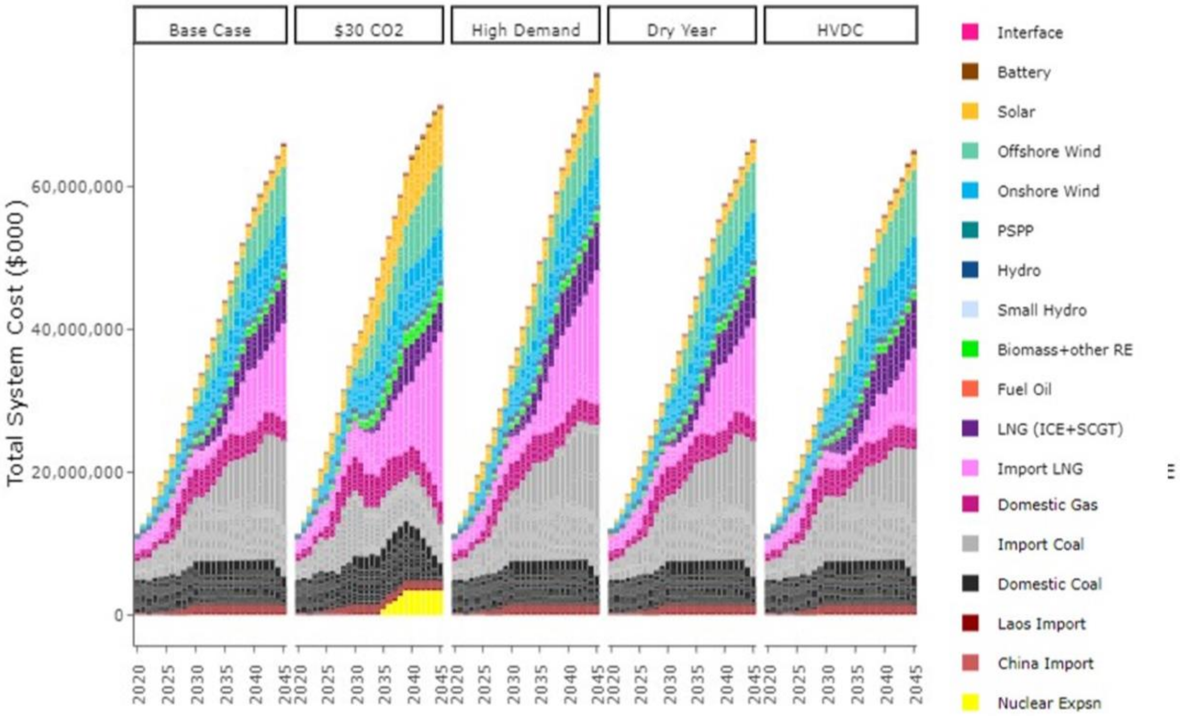
The total system costs for the operational sensitivities are shown in Figure 5-35. When fuel and externality costs are considered, the *High Demand* sensitivity has the highest total system cost. In the *\$30 CO_2* sensitivity, the cost contribution of coal decreases sharply as the price of CO_2 reaches US\$30/ton.

The *HVDC* sensitivity, despite having high investment costs, has the smallest total system cost. The HVDC connection transfers the offshore wind generation to the North, replacing the need for fossil resources, which leads to a lower operational cost and lower overall system cost. Table 5-4 shows the total system costs for the *Base Case* and the *HVDC* sensitivities in 5-year increments. The cost saving benefit of the HVDC connection started after its installation in 2030 and remains through the end of the planning horizon. This shows that new transmission interconnections between regions can significantly change how the system is built and dispatched. As such, it is important to further evaluate the cost and benefits of building an HVDC line in Vietnam, including its timing.

Table 5-4: Total System Costs for the *Base Case* and *HVDC* sensitivity

Total System Cost (Thousands USD)		
Year	Base Case	HVDC
2020	11,387,876	11,387,876
2025	20,233,216	20,218,321
2030	31,777,931	32,070,728
2035	44,084,007	43,810,013
2040	57,106,764	56,489,678
2045	66,113,722	65,546,448

Figure 5-35: Total System Costs for Operational sensitivities



The production and emission cost for the operational sensitivities is shown in Figure 5-36. The impact of the additional externality costs in the *$30 CO_2* sensitivity allows it to have the lowest production cost but the highest emission cost of all the operational sensitivities.

Figure 5-36: Operational (production + externality) Costs for Operational sensitivities

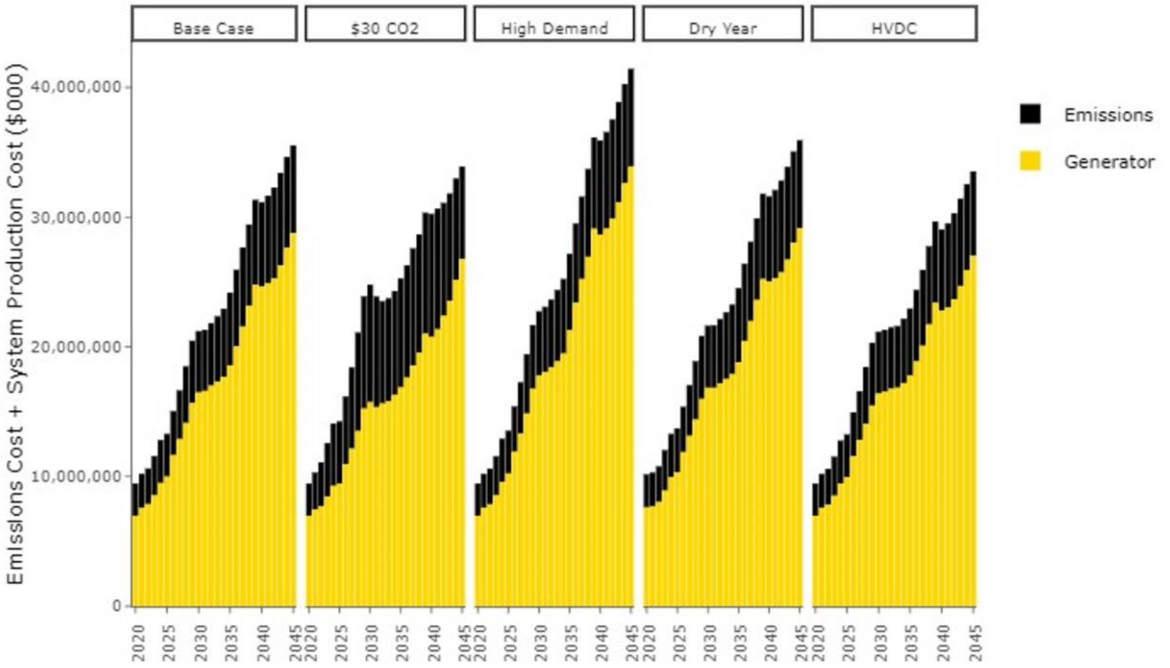
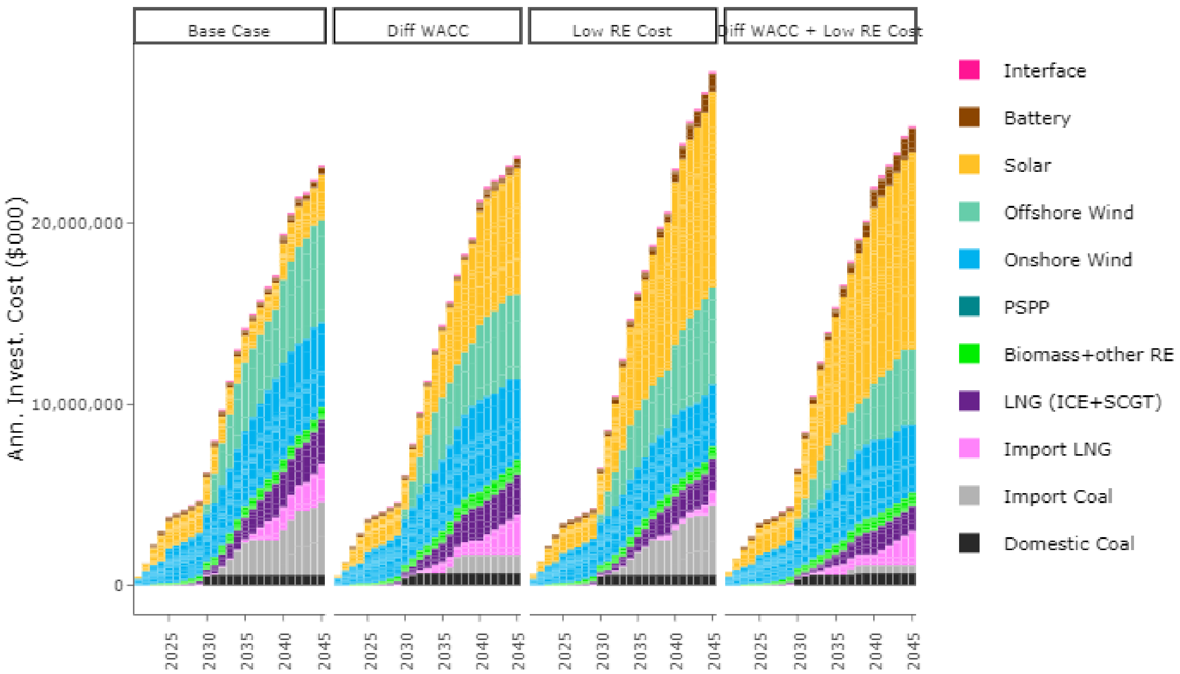


Figure 5-37 shows the annualized investment costs for the cost-reduction sensitivities. Greater investment in solar expansions throughout the time horizon contributes more to the annualized investment costs in these sensitivities. The higher WACC for coal reduces the investment in new imported coal plants, until 2035 when some new imported coal plants are built.

Figure 5-37: Annualized Investment Costs for the cost-reduction sensitivities



The yearly cost patterns for the *Low RE Cost* sensitivity is similar to that of the *Base Case*, where there is steady expansion through 2045; however, the *Low RE Cost* sensitivity has the highest investment cost due to more solar capacity being built.

Even though it has the highest investment cost, the *Low RE Cost* sensitivity has a lower total system cost than the *Base Case* and *Diff WACC* sensitivity (Figure 5-38) once fuel and emissions costs are taken into consideration (Figure 5-39). The *Diff WACC+Low RE Cost* sensitivity has the lowest system cost because it replaces new coal builds with LNG and significantly utilizes the low-cost solar. The cost-reduction sensitivities show that lowering RE costs (through policy) can reduce the overall system costs, and therefore power tariffs, for Vietnam.

Figure 5-38: Total System Cost for the cost-reduction sensitivities

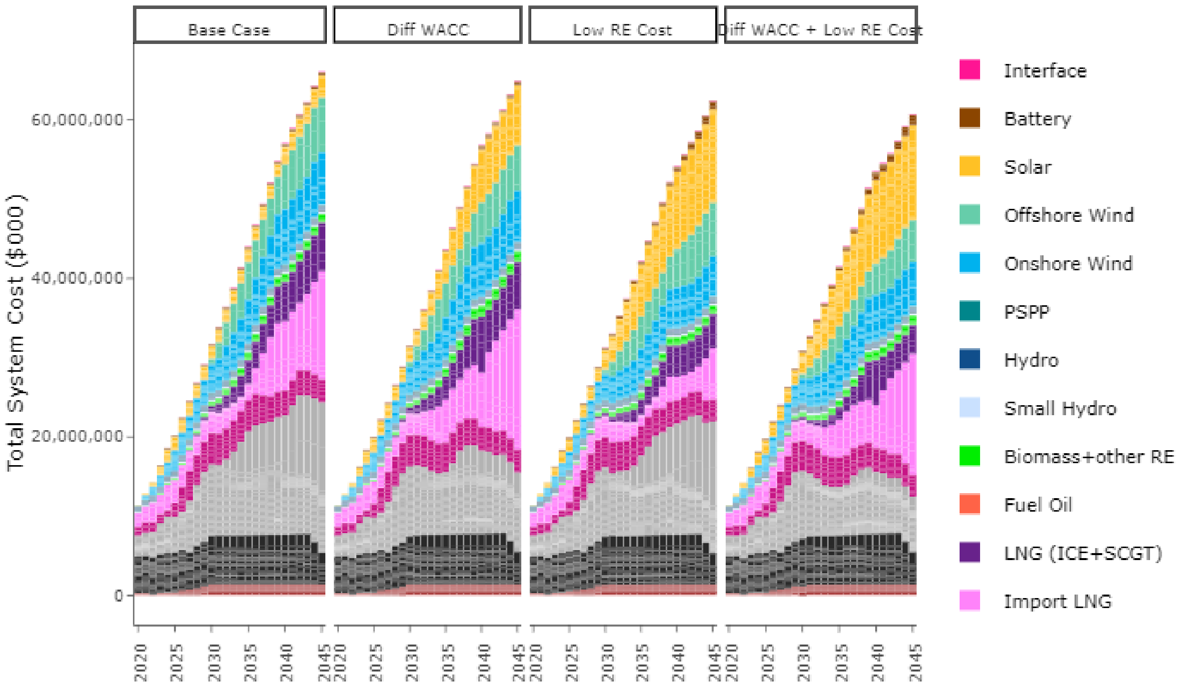
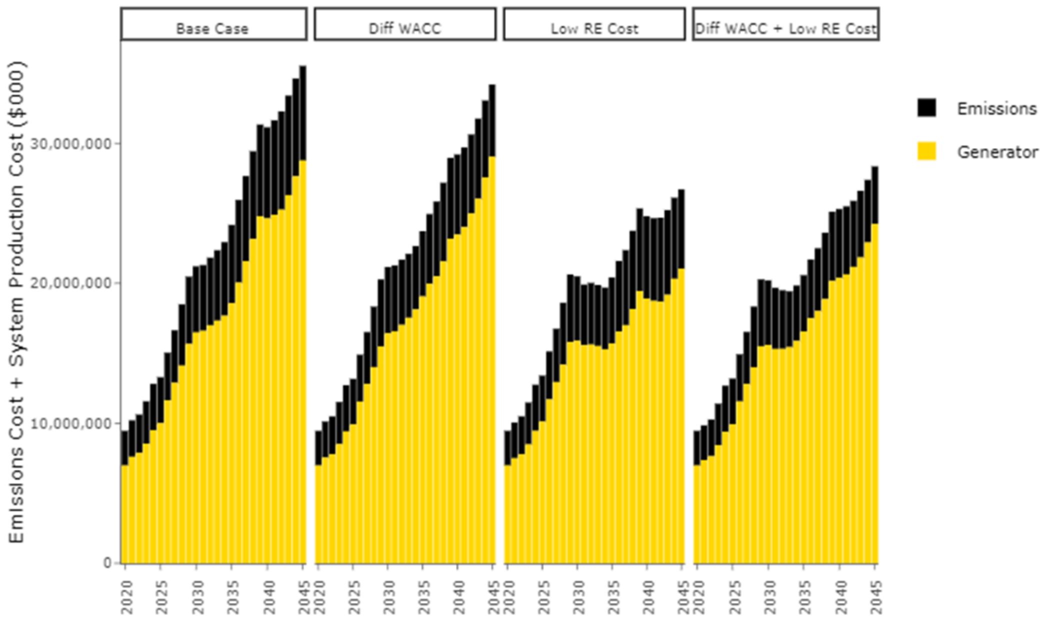


Figure 5-39: Operational (production + externality) for cost-reduction sensitivities



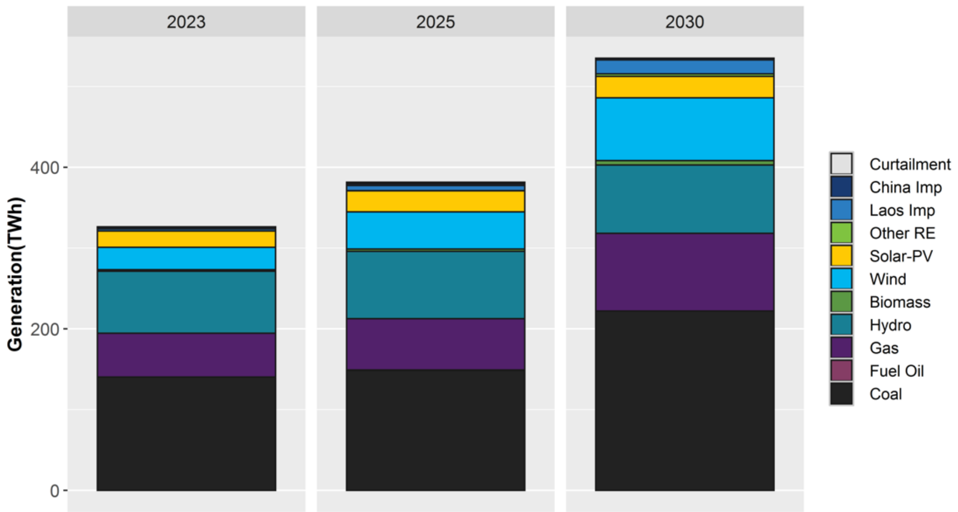
6 PRODUCTION COST ANALYSIS OF PCM RESULTS

This chapter examines the operational impact of the generation results and transmission assumptions from the LT model's *Base Case* scenario. The analysis covers three selected years –2023, 2025, and 2030. Years beyond 2030 are not discussed due to uncertainty in transmission assumptions that require validation from Vietnam's transmission planners.

6.1 GENERATION MIX

Figure 6-1 shows the annual generation mix in the three target years. Excluding biomass and imports, solar and wind (variable renewable energy or vRE) generation have the highest annual growth rate[3] at 12% from 2023 to 2030, followed by gas and coal generation at 9% and 7%, respectively. Hydro generation has a modest annual growth rate at 1%. In 2030, the projected energy mix in Vietnam consists of 41% coal, 19% vRE, 18% gas, 16% hydro, 4% imports, and 2% other RE. The generation profile indicates a 37% RE percentage in the generation mix, which is well above the 32% target under the *Base Case* scenario.

Figure 6-1: Annual Generation Mix

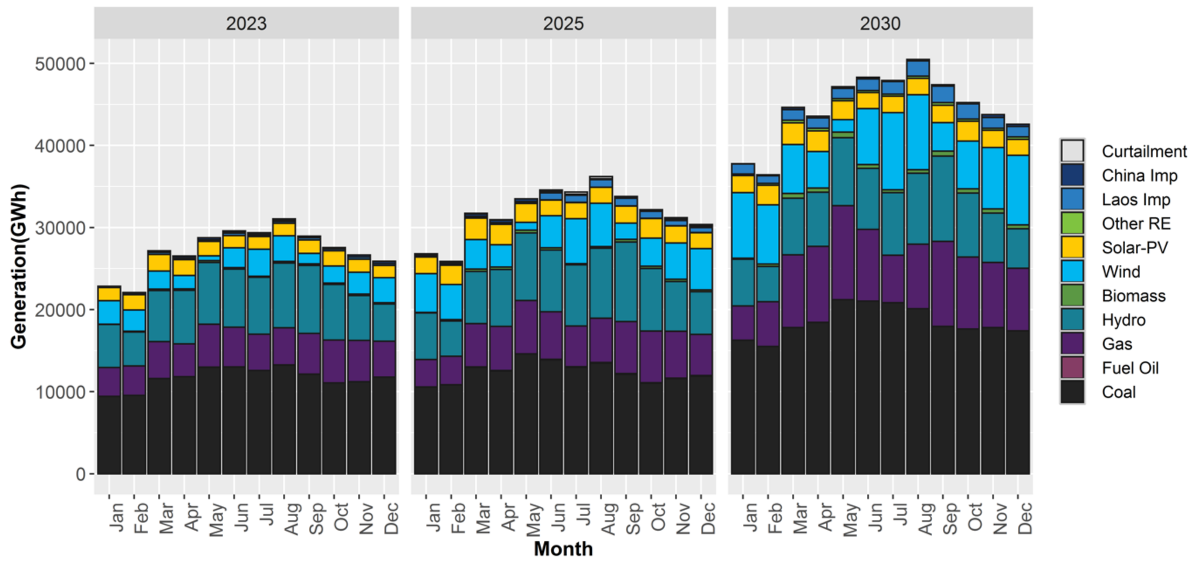


Note: PSPP is categorized as Hydro. LNG (ICE+SCGT) is categorized as Gas. Batteries are excluded.

Figure 6-2 shows the monthly generation mix in the three target years. There is a negative correlation between the monthly generation of wind and gas – as wind generation increases, gas generation decreases. Excluding the months of July and August, there is also a negative correlation between the monthly generation of wind and hydro. July and August are high wind and hydro generation months. While wind resources depend on meteorological patterns, hydro resource usage is based on water management. Hydro generators are required to release more water for flood control during rainy months (i.e., July and August). From 2023 to 2030, the negative correlation between wind and gas (or hydro) is strengthened as more wind is integrated into the grid.

[3] Annual growth rate is calculated as (Final value/Beginning value)^(1/Time in years) - 1

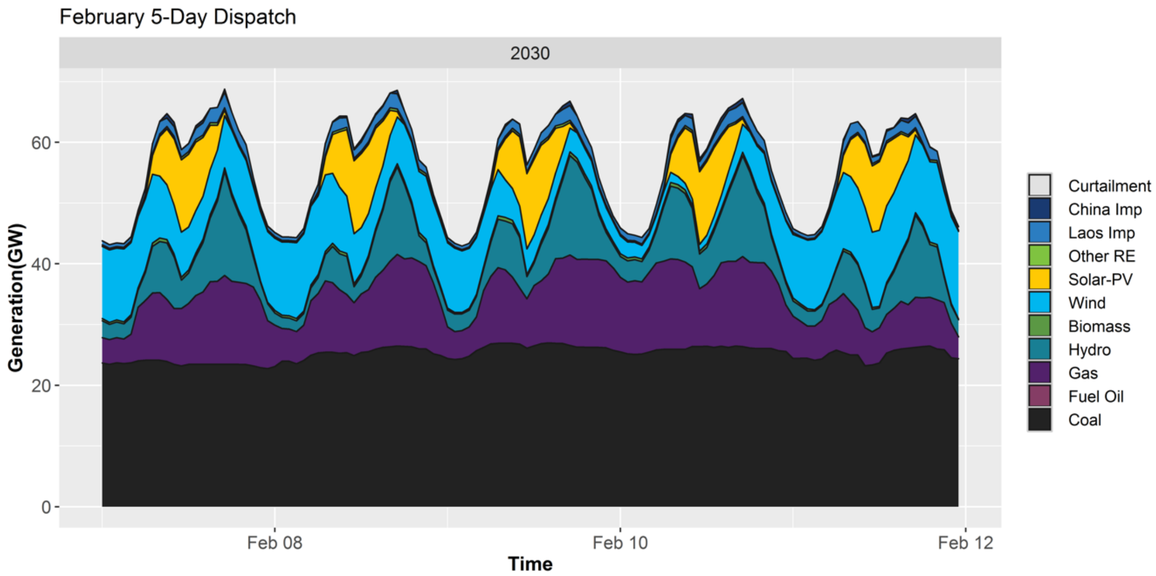
Figure 6-2: Monthly Generation Mix



Note: PSPP is categorized as Hydro. LNG (ICE+SCGT) is categorized as Gas. Batteries are excluded.

Figure 6-3 shows the selected low demand dispatch days in 2030, demonstrating hydro generation's role in providing flexibility to the grid. These low demand days will occur during the Tet holidays in Vietnam.

Figure 6-3: Selected Low Demand Dispatch Days in 2030



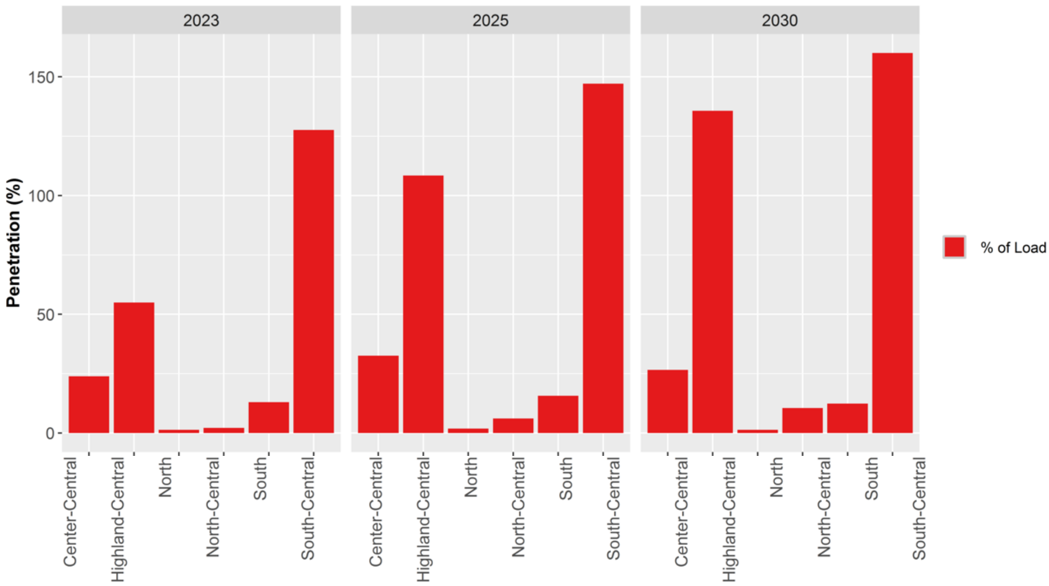
Note: PSPP is categorized as Hydro. LNG (ICE+SCGT) is categorized as Gas. Batteries are excluded. See Figure 8-11 for the dispatch by resource, where PSPP and LNG (ICE+SCGT) are categorized separately.

From midnight to early morning, hydro generators operate at a low level because of low demand. When wind generation is high during this time period, hydro generation tends to go lower while maintaining the minimum hydro storage release requirements. As the load increases, hydro generation changes to accommodate more vRE generation, avoiding vRE curtailment. Along with gas generation, hydro generation increases in the afternoon, when solar generation is not available and wind generation is low, to meet the peak load. See Appendix A for the dispatch stack of additional selected days in 2030.

6.2 VRE PENETRATION AND CURTAILMENT

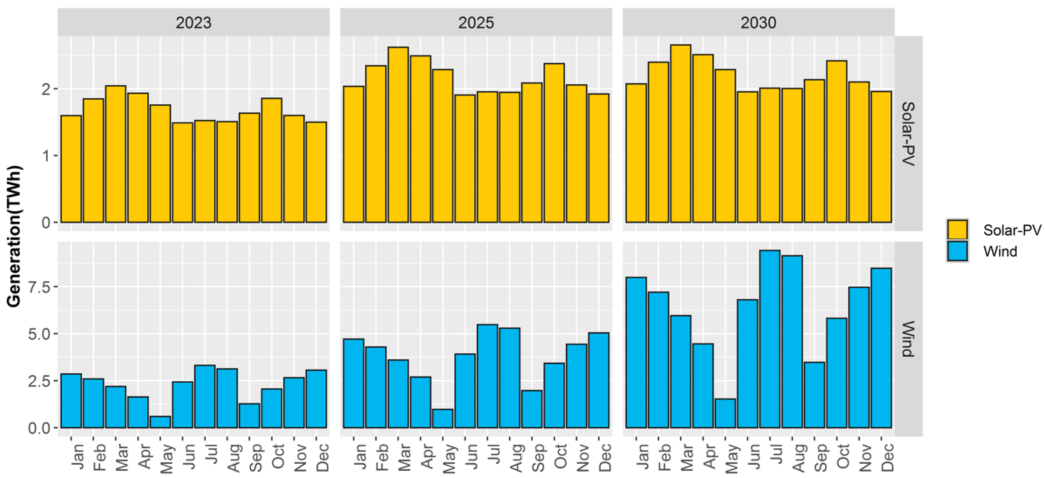
On a national level, the projected vRE penetration as a percentage of the total load increases from 15% in 2023 to 19% in 2030. When calculated on a regional level (Figure 6-4), a high vRE penetration is seen in the Center-Central, Highland-Central, and South-Central regions. In 2023, vRE penetration in the South-Central region is already above 100%, indicating that this region is a net exporter of vRE generation. In 2025, the Highland-Central region also becomes a vRE net exporter. The North region, on the other hand, continues to have the lowest vRE penetration across the years analyzed.

Figure 6-4: vRE Penetration by Region



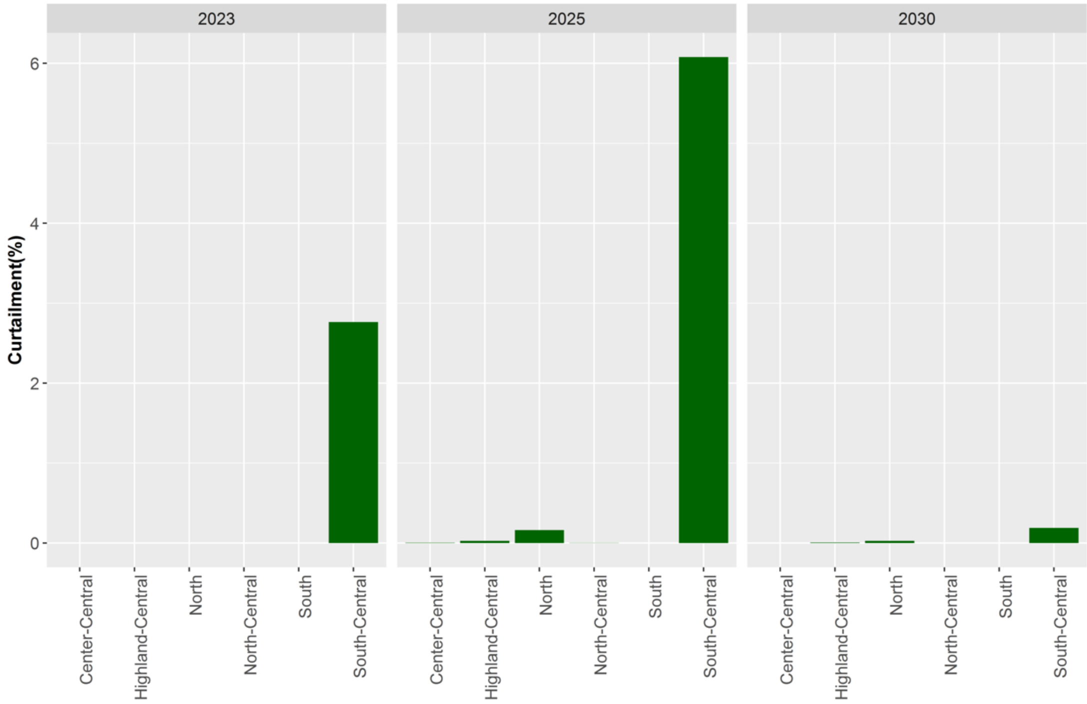
On a monthly basis, solar generation is relatively flat across all the months, with peaks in March and October (see Figure 6-5). Wind generation is the highest in the summer months (July and August) and the winter months (December to February), with low periods in May and September.

Figure 6-5: Monthly VRE Generation



The vRE curtailment as a percentage of available vRE capacity is negligible across all the regions, except in the South-Central region (see Figure 6-6). The vRE curtailment percentage in this region increases from 3% in 2023 to 6% in 2025, then decreases to 0.3% in 2030. In 2023 and 2025, the interface connecting the Center-Central and South-Central regions is congested for more than 90% of the year. This indicates the need for additional transmission to accommodate more vRE generation. In 2030, the increase in the export limit of Mid Central-to-South Central interface from 270 MW to 1,500 MW lowers the curtailed vRE in the region by enabling more vRE generation in the grid (see Mid Central-South Central in Figure 6-14).

Figure 6-6: vRE Curtailment by Region



6.3 PLANT LOAD FACTORS, ANNUAL STARTS, AND HOURS AT MINIMUM STABLE LEVEL

Plant load factor (PLF) is equal to total annual generation divided by the product of maximum capacity and 8760 hours. The median (50th percentile) plant load factors of solar, wind, and hydro power plants are relatively flat – 17% for solar, 48-50% for wind, and 39-40% for hydro. While the median PLFs of gas power plants are decreasing, the median PLFs of coal power plants are changing.

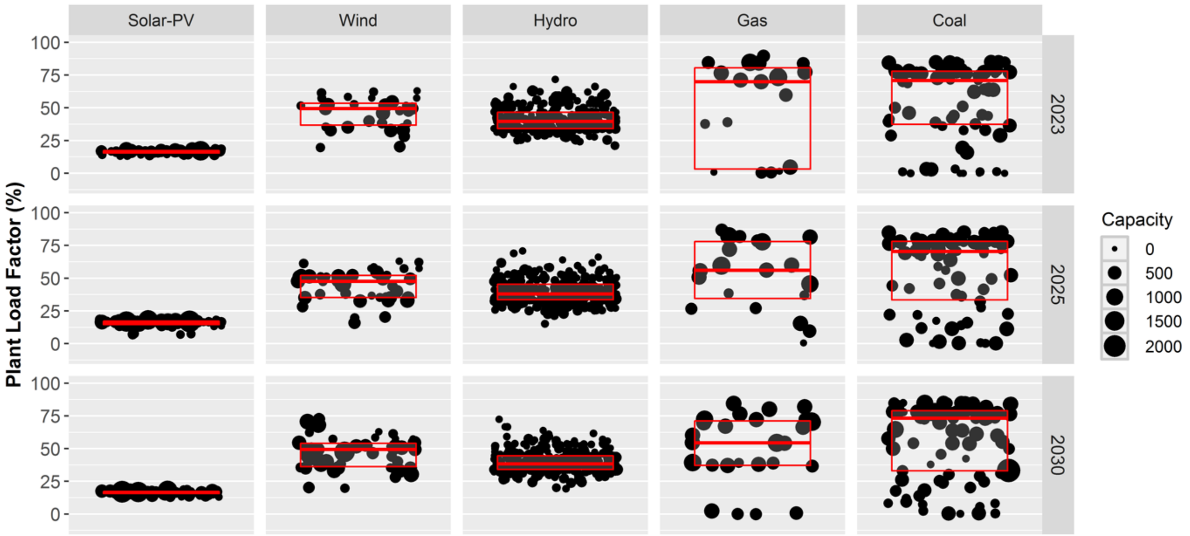
Table 6-1: Plant Load Factor by Resource Type (%)

Percentile	Solar			Wind			Hydro			Gas			Coal		
	2023	2025	2030	2023	2025	2030	2023	2025	2030	2023	2025	2030	2023	2025	2030
25th	15	14	16	35	35	36	34	34	34	2	27	37	37	22	30
50th	17	17	17	50	48	50	40	40	39	70	56	55	70	69	73
75th	17	17	17	53	52	55	47	47	45	78	78	71	78	78	79

Note: PSPP and LNG (ICE+SCGT) are excluded.

The difference between 25th and 75th percentile of PLFs for solar, wind, and hydro power plants is below 20%. On the other hand, gas and coal power plants have a large difference in PLFs, the largest of which (76%) occurs in gas power plants in 2023. The PLF difference for gas plants declines to 34% in 2030 when there is an increase in gas units' capacity utilization at the 25th percentile.

Figure 6-7: Plant Load Factor by Resource Type



Note: PSPP and LNG (ICE+SCGT) units are excluded. See Figure 8-12 for the PLFs of PSPP and LNG (ICE+SCGT) units.

Some gas and coal units operate at very low PLF – seven gas units operate below 10%, while 17 coal units operate below 5% PLF. This may be due to the annual fuel limits across the national gas and coal fleet, causing the less efficient thermal units to have lower capacity utilization, as shown in Figure 6-8 and Figure 6-9.

Figure 6-8: Heat Rates of Gas Units with Very Low PLF

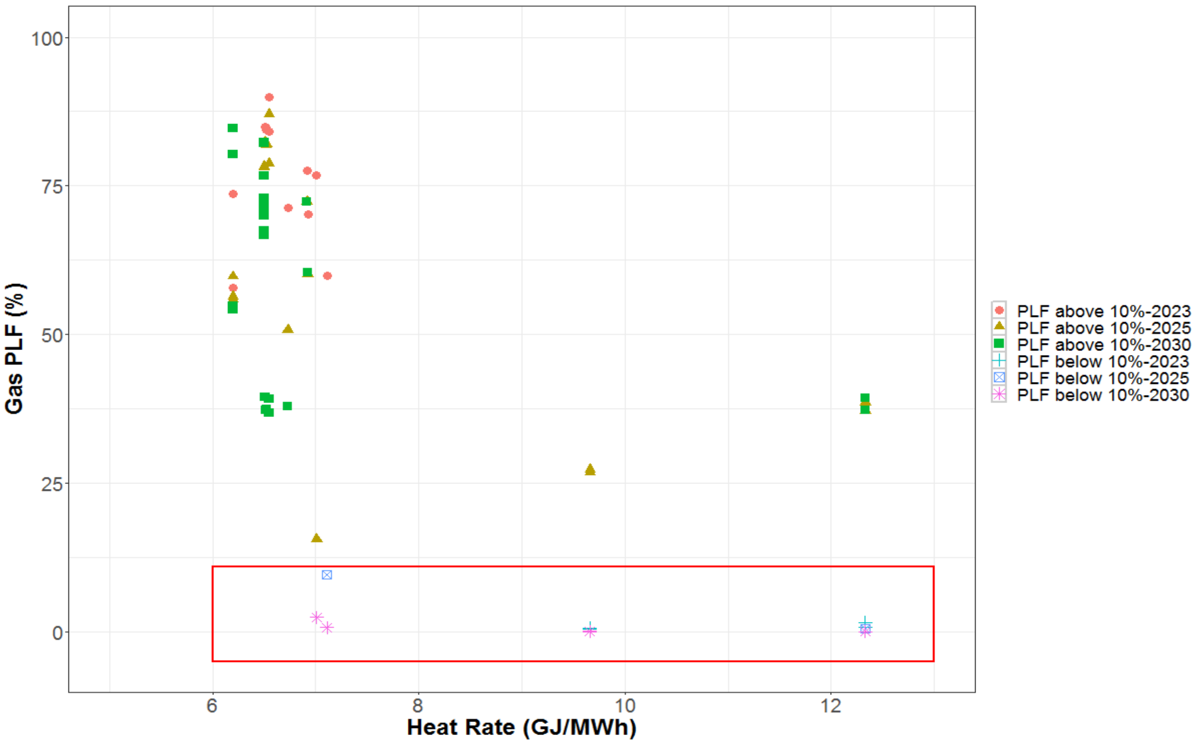


Figure 6-9: Heat Rates of Coal Units with Very Low PLF

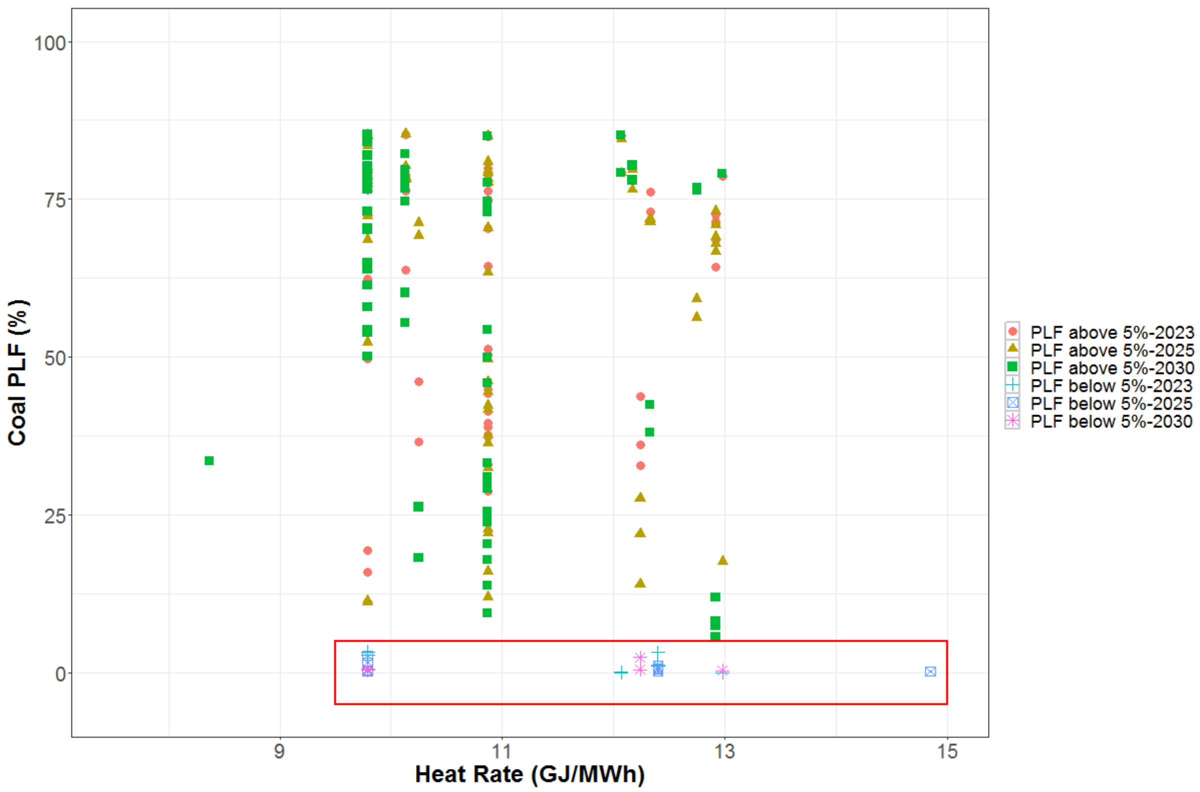
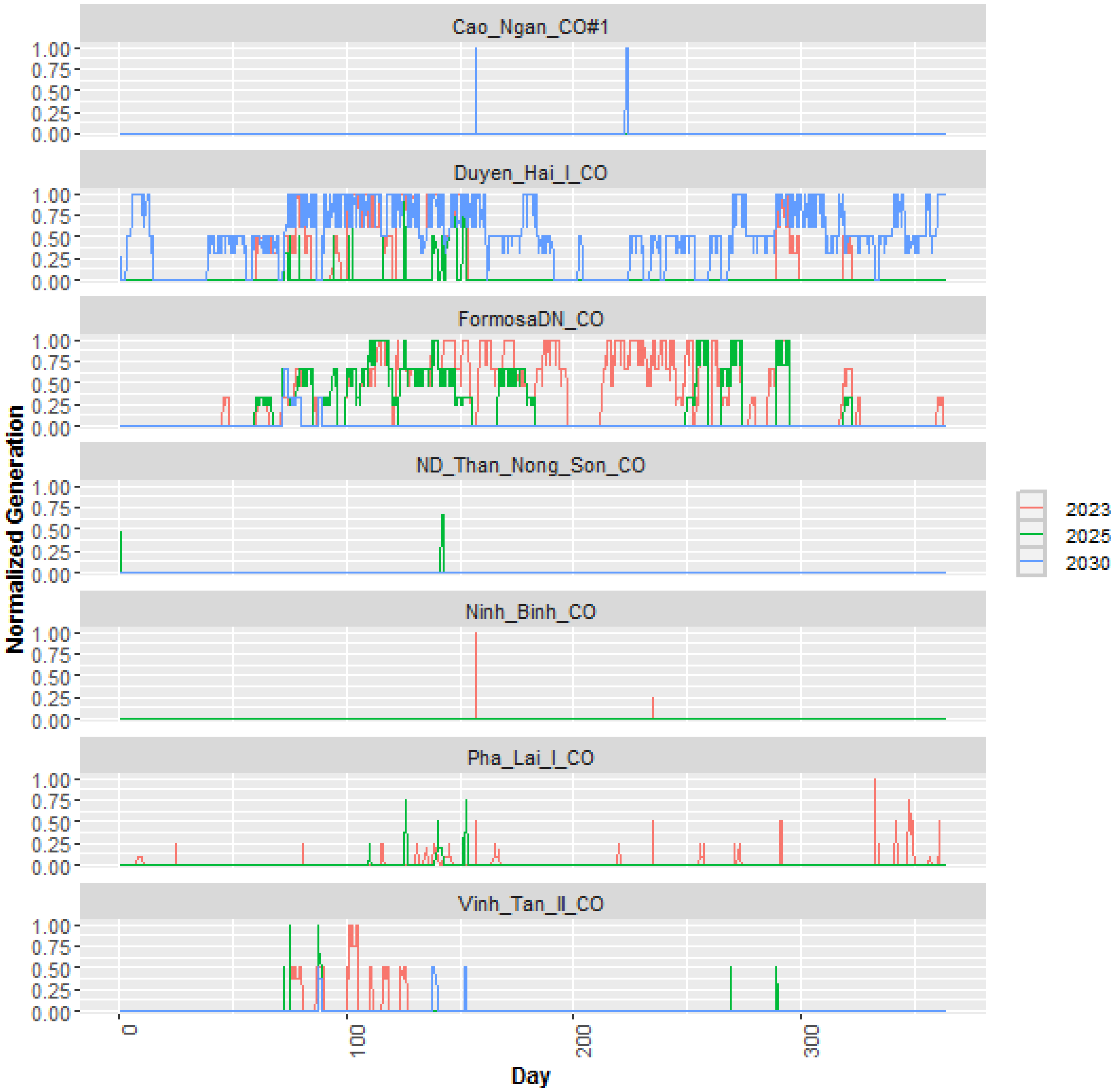


Figure 6-10 shows the cycling profiles of the seven coal plants (or 17 coal units) with very low PLF. Most of the coal plants experience a decreasing number of cycles from 2023 to 2030, except for Duyen Hai. For example, Pha_Lai_I_CO#1's total number of starts falls from 7 in 2023 to 5 in 2025. In 2030, some of these plants are no longer operating – Ninh_Binh_CO, and Pha_Lai_I_CO—and can therefore be potential early retirement candidates. On the other hand, some units, such as Duyen Hai, experienced increase use in 2030.

Figure 6-10: Cycling of Coal Plants with PLF Below 5%



Note: Normalized generation is calculated as hourly generation over maximum capacity. In 2023 and 2025, the PLFs of FormosaDN_CO units are above 10%. In 2030, the PLFs of Duyen_Hai_I_CO units are above 50%.

This type of chronological analysis of power plants suggests that there is a need for a detailed analysis of the generators' input parameters and the maximum fuel availability limits. This can help evaluate the implications of the low PLF of these units. The cycling and plant load factors of the power plants are influenced by the allocation decisions in the Medium-Term (MT) Schedule[4], which will have to be reviewed in more detail in future analysis.

[4] Details of MT Schedule are discussed in the *"Assessment of Revised Power Development Plan 7 by using Production Cost Model with PLEXOS"* [the 'PCM-Report'].

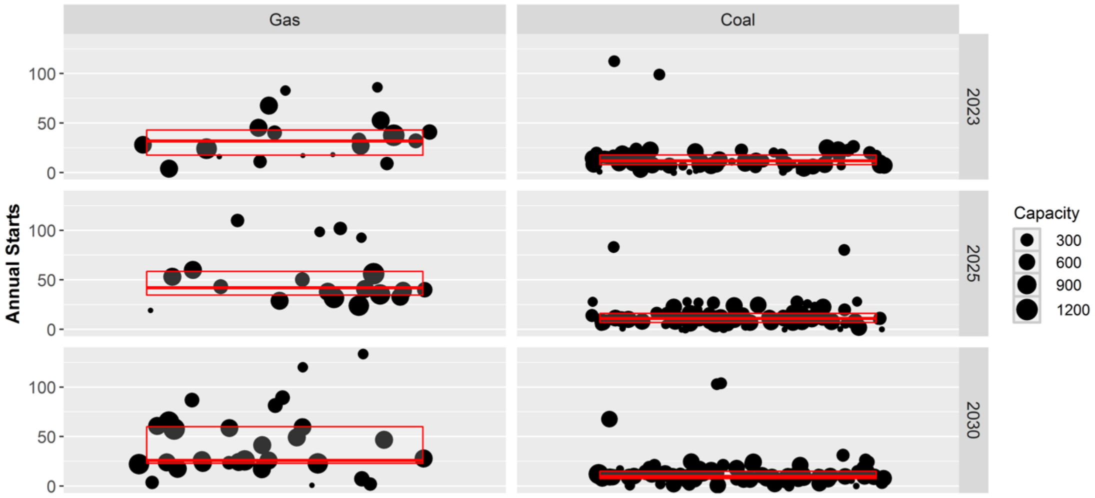
The annual starts of more than half of the gas units in 2030 is lower than in 2023 and 2025, signifying an increased role of gas generation as a "base load" resource and in providing flexibility to the grid (see Figure 6-11). The median annual starts of gas units increases from 2023 to 2025, then decreases in 2030. The percentile difference between 25th and 75th percentile increases from 24% in 2023 to 38% in 2030 as more vRE is integrated into the grid. On the other hand, the median annual starts of coal units experience a modest decrease from 2023 to 2030.

Table 6-2: Annual Starts of Gas and Coal Units

Percentile	Gas			Coal		
	2023	2025	2030	2023	2025	2030
25th	17	33	22	8	7	7
50th	32	41	26	12	11	10
75th	41	58	60	18	16	15

Note: LNG (ICE+SCGT) are excluded.

Figure 6-11: Annual Starts of Gas and Coal Units



Note: LNG (ICE+SCGT) units are excluded.

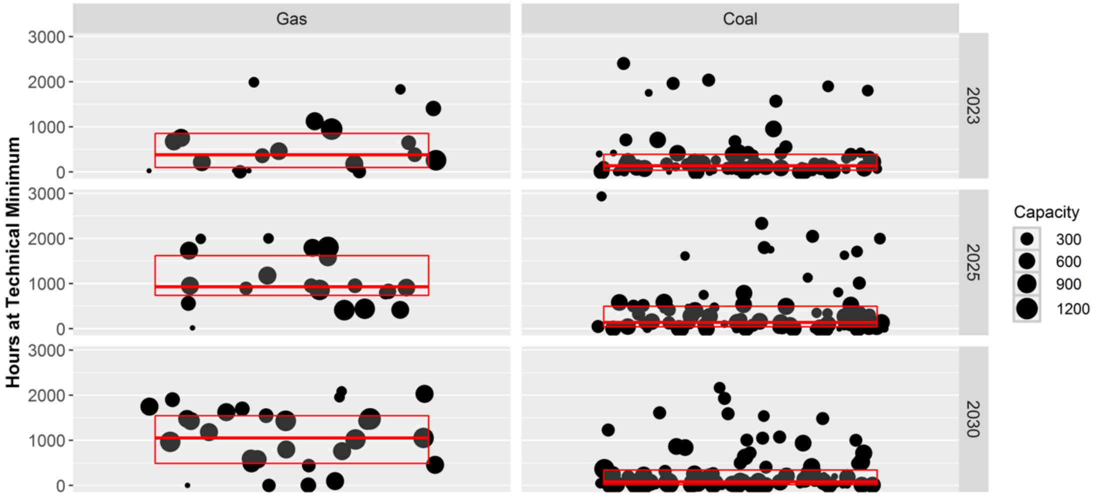
By only considering the operating hours at a minimum stable level (MSL), the median annual hours of gas units increases by almost three times between 2023 and 2030 (see Figure 6-12). Although the annual hours of coal units remain modest, the number of coal units operating at MSL for more than 10% of the year (approx. 876 hours) increases from 8 in 2023 to 14 in 2030. These indicate an increasing need for flexible generation as more vRE gets integrated onto the grid.

Table 6-3: Annual Hours at MSL of Gas and Coal Units

Percentile	Gas			Coal		
	2023	2025	2030	2023	2025	2030
25th	25	561	456	36	56	27
50th	383	910	1055	144	157	93
75th	755	1583	1546	390	518	407

Note: LNG (ICE+SCGT) are excluded.

Figure 6-12: Annual Hours at MSL of Gas and Coal Units

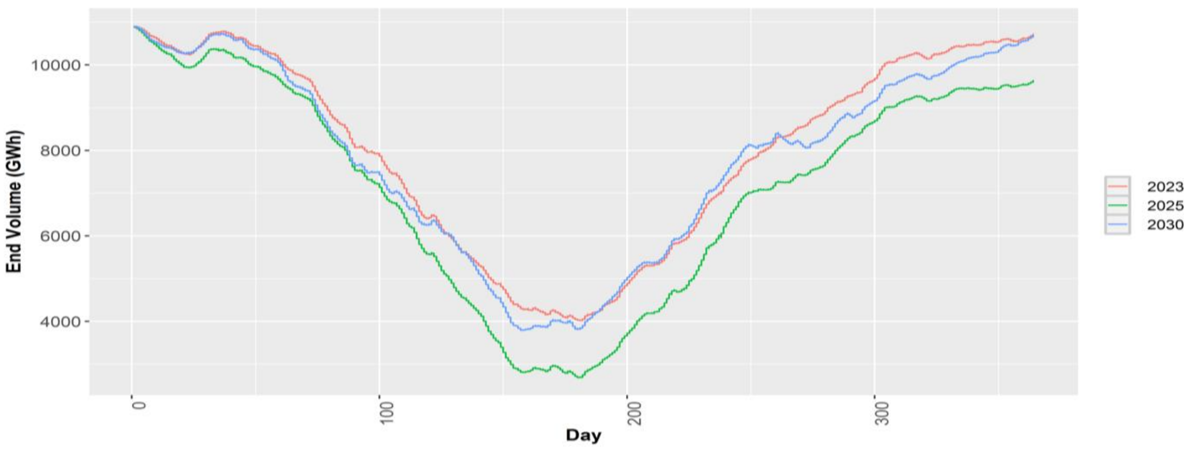


Note: LNG (ICE+SCGT) are excluded.

6.4 HYDRO STORAGE TOTAL VOLUME

Figure 6-13 illustrates the hydro storage scheduling in 2023, 2025, and 2030, where the lowest total volume occurs in mid-July. In 2023 and 2030, the total volume at the end of the year is able to return to the initial volume for the next year's supply. On the other hand, the total volume at the end of 2025 is lower than the initial volume by more than 10%, signaling overutilization of hydro generation in that year. This is problematic for the following year in 2026. The PCM assumptions used in this study consider hydro storage targets as soft constraints, with a high penalty price. These results suggest further analysis and changes in assumptions are needed to better represent the hydropower usage in Vietnam.

Figure 6-13: Total End Volume of Hydro Storages



6.5 TRANSMISSION FLOW

Figure 6-14 shows the changes in the energy flow across the interfaces from 2023 to 2030. All the interfaces, except the Mid Central-to-High Land interface, have increased flows. Although the capacity of many interfaces increases over time, congestion across the central regions still exists. This indicates that further analysis, using PSSE, would be helpful to understand the necessary increases in interface capacity in the central regions.

Figure 6-15 shows total congestion hours by interface. The highest increase in capacity is for the North-to-North Central interface, where the import and export limits are more than doubled from 2023 to 2030. The capacity addition reduces the congestion from 40% in 2023 to 20% in 2025 and further to 10% in 2030. This indicates that there is room for additional expansion to avoid potential congestion that could limit vRE generation. In 2030, the flow towards the North exceeds the 2025 interface limit 90% of the year and the 2023 interface limit 99% of the year. This demonstrates the high value of the expansion of this interface.

Figure 6-14: Flow Duration Curve by Interface

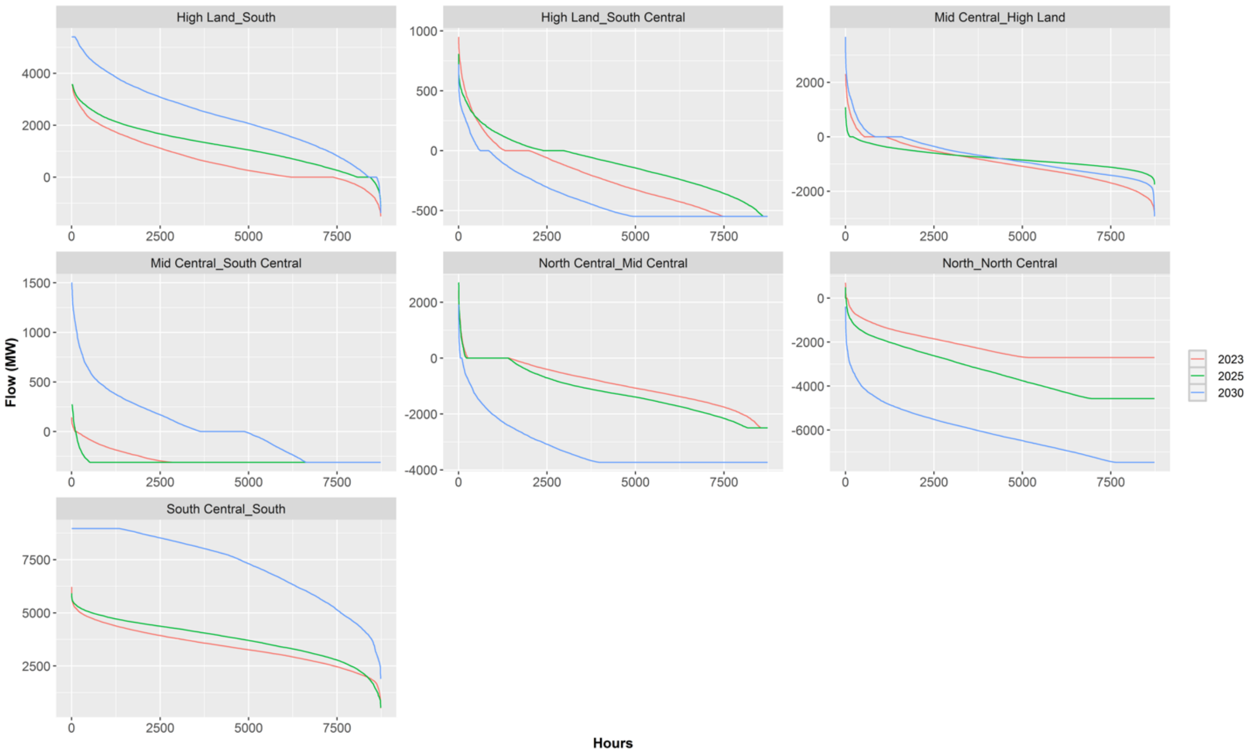
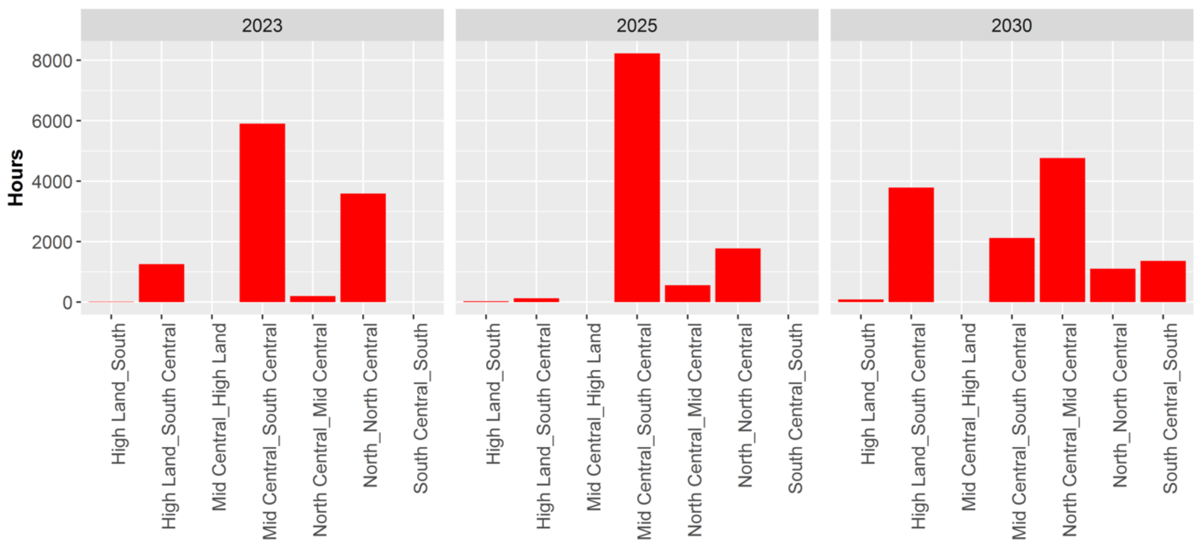


Figure 6-15: Total Congestion Hours by Interface



In 2030, the North Central-to-Mid Central and High Land-to-South Central interfaces are congested for more than 40% of the year. The Mid Central-to-South Central, South Central-to-South, and North-to-North Central interfaces are congested for more than 10% of the year. This congestion suggests that further transmission expansion in the central region is warranted.

6.6 IMPLICATIONS FOR GREATER RENEWABLE ENERGY INTEGRATION

Vietnam's power system can support more vRE generation, which can reduce the country's dependence on imported fuels and lower total system costs. Consequently, the power system can reduce additional cost of fuel as well as the level of emissions (both CO_2 and other air pollutants).

The country's grid already has existing flexibility to enable more vRE generation. This is provided by hydro and gas generation as explored in Section 6.1. The LT model's *Base Case* scenario targets 43% RE by 2050 as mentioned in Chapter 4. To achieve this target, Vietnam's power system will require more flexibility from both demand-side and supply-side resources to enable additional vRE generation and grid integration. This study has revealed additional areas that warrant further study and analysis to better understand the ways to increase grid flexibility in Vietnam. These include:

- **Price analysis –** can provide a signal of under- or over-capacity in the system.
- **Transmission network analysis, including congestion** – can identify the location of the transmission needs.
- **vRE location analysis** (similar to renewable energy zones) – can identify the location of best vRE resources.
- **Sensitivity analysis on battery storage location and duration** – can identify and quantify the battery storages beneficial in the system.
- **Inclusion of more weather-years into the analysis –** can capture more uncertainties in the system.
- **Extreme weather analysis** – can examine the technical challenges of the grid during extreme weather events.
- **vRE capacity credit analysis** – can quantify the capacity value of vRE generation that impacts the reserve margin of the grid.
- **Forced outage analysis –** can capture the uncertainty in the system related to forced outages.
- **Maintenance scheduling analysis** – can improve the allocation of resources across the planning horizon.
- **Analysis of hourly chronological dispatch of coal units** – can help to consider whether the coal units are being operated realistically, considering the technical and maintenance limitations. Such analysis will be useful for evaluating the potential thermal units that can provide flexibility to the grid.

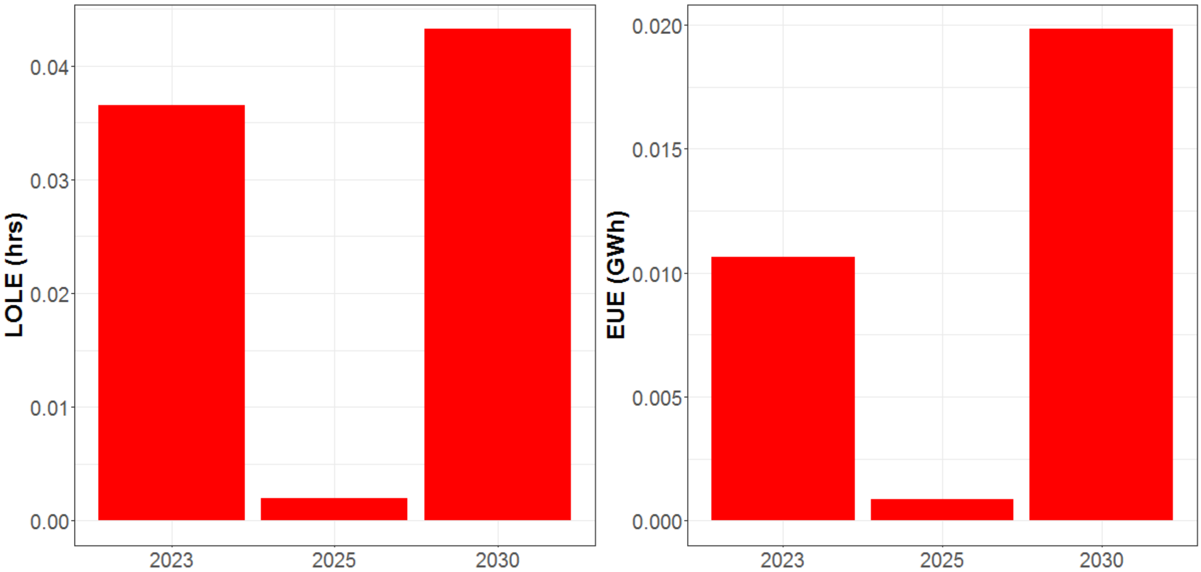
7 RESOURCE ADEQUACY ANALYSIS OF PCM

In addition to production cost analysis, a resource adequacy analysis was conducted using NREL's Probabilistic Resource Adequacy Suite (PRAS) to assess Vietnam's power system adequacy using the following three metrics:

- **Loss-of-load expectation (LOLE)** refers to the expected value of the total number of periods with shortfall across the studied horizon. The unit of LOLE in this study is hours.
- **Expected unserved energy (EUE)** refers to the expected value of the total energy shortfall across the studied horizon. The unit of EUE in this study is Gigawatt-hours (GWh).
- **Normalized EUE (NEUE)** refers to the expected value of the total load that will not be served across the studied horizon. This is calculated as the EUE over the total load multiplied by 1,000,000. The unit of NEUE in this study is parts per million (ppm).

In the modeling process, the generation and transmission results from the production cost model (PCM) are imported into PRAS. Using a Monte Carlo method, the PRAS tool simulates outage events to capture the uncertainties in generator availability and inter-regional power transfer constraints in order to quantify the energy shortfall risk (see Appendix B).

Figure 7-1: LOLE and EUE



The preliminary results indicate LOLE's lower than 0.05 hour and EUE's lower than 0.02 GWh across the studied time period – 2023, 2025, and 2030 (see Figure 7-1). The projected LOLE's meet Vietnam's reliability criterion of 12 hours. Normalizing the EUEs translates to NEUE's lower than 0.04 ppm, which also meets the typical standards set in other countries (10-30 ppm).[5]

Figure 7-2 shows the EUE by region. On a regional level, the unserved energy is expected in the North and South regions. Other regions have zero EUE. The EUE is the highest in 2023 in the North region and in 2030 in the South region.

Figure 7-2: EUE by Region

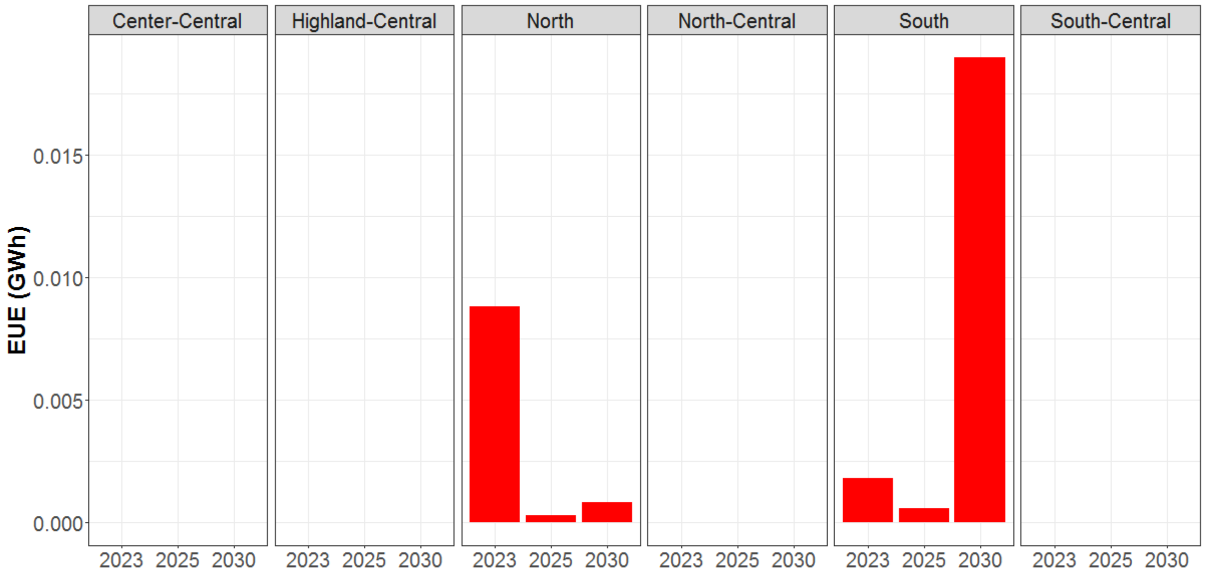
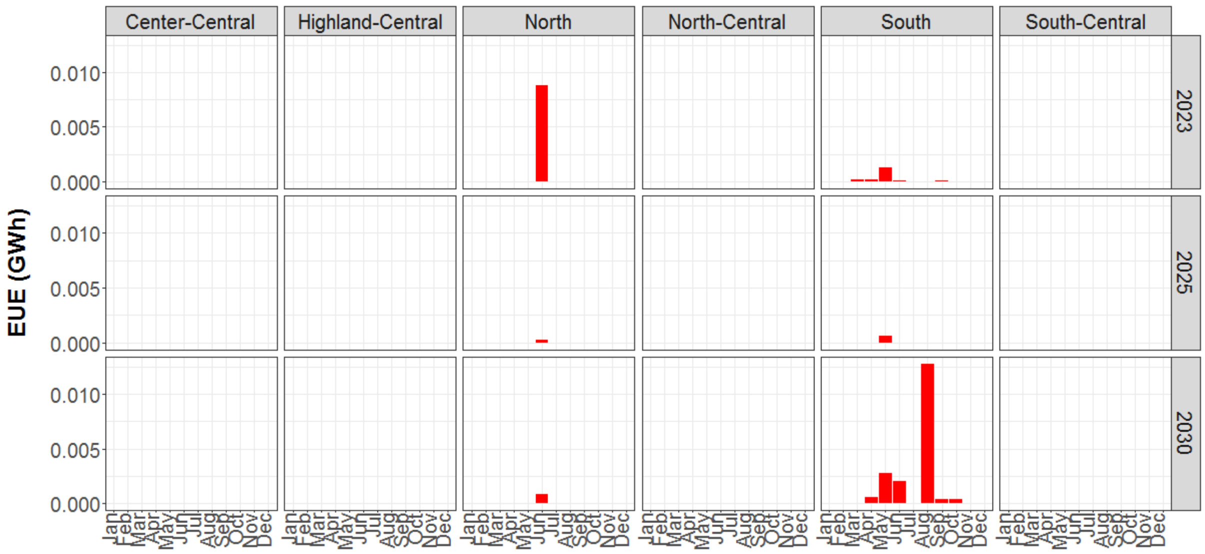


Figure 7-3: Monthly EUE by Region



[5] AESO, Resource Adequacy, A Comparison of Reliability Metrics, https://www.aeso.ca/assets/Uploads/Capital-Power-Reliability-Target-Summary-CM.pdf.

On a monthly basis, the EUE in the North region is projected to occur in June in 2023, 2025, and 2030. On the other hand, the EUE in the South region is distributed across the year. In 2023 and 2025, the highest EUE is observed in May. In 2030, the highest EUE is forecasted in August, followed by May and June (see Figure 7-3).

In general, the unserved energy occurs in the North region in the afternoon at 13:00-14:00 hours. In the South region, most of the unserved energy events happen in the afternoon and evening at 15:00 and 18:00-20:00 hours. These events coincide with the time of the peak load in their respective regions (see Figure 8-1, Figure 8-2, and Figure 8-3).

It is important to further analyze options for reducing the LOLE in the country. For demonstration purposes, three options that could reduce the LOLE were considered as part of an initial analysis:

- Increase the capacity of the batteries installed in the North;
- Increase the North-Central-to-North interface capacity; and
- Use a combination of battery and interface capacity increases.

The results for these options are shown in Table 7-1. This demonstrates the value of using PRAS for further analysis of potential supply and demand side options to increase the system's reliability.

Table 7-1: Scenario Analysis of Options to Reduce LOLE

Year	Scenario	LOLE (hours)	EUE (GWh)	NEUE (ppm)
2023	Base Case	0.037	10.6	0.033
	2x Battery	0.010	3.0	0.009
	Higher N-NC Interface Limit	0.007	1.8	0.006
	2x Battery + Higher N-NC Interface Limit	0.006	1.8	0.006
2025	Base Case	0.002	0.9	0.002
	2x Battery	0.001	0.6	0.002
	Higher N-NC Interface Limit	0.001	0.6	0.002
	2x Battery + Higher N-NC Interface Limit	0.001	0.6	0.002

The preliminary results of the resource adequacy analysis presented in this chapter reveal that Vietnam's grid meets the LOLE reliability criterion and the typical NEUE standards. However, no definitive conclusion can be drawn at this time. There are other factors, such as fuel limits for coal/gas, minimum release requirements, load uncertainty, VRE uncertainty, etc., which are important for resource adequacy and need to be suitably included in the analysis. We will continue to expand the Vietnam PRAS model to include these factors and analyze the results to better assess the resource adequacy of the country's power system.

8 APPENDIX A

This appendix contains additional figures that support the analysis done in the PCM.

Figure 8-1: Diurnal Pattern of EUE by Region in 2023

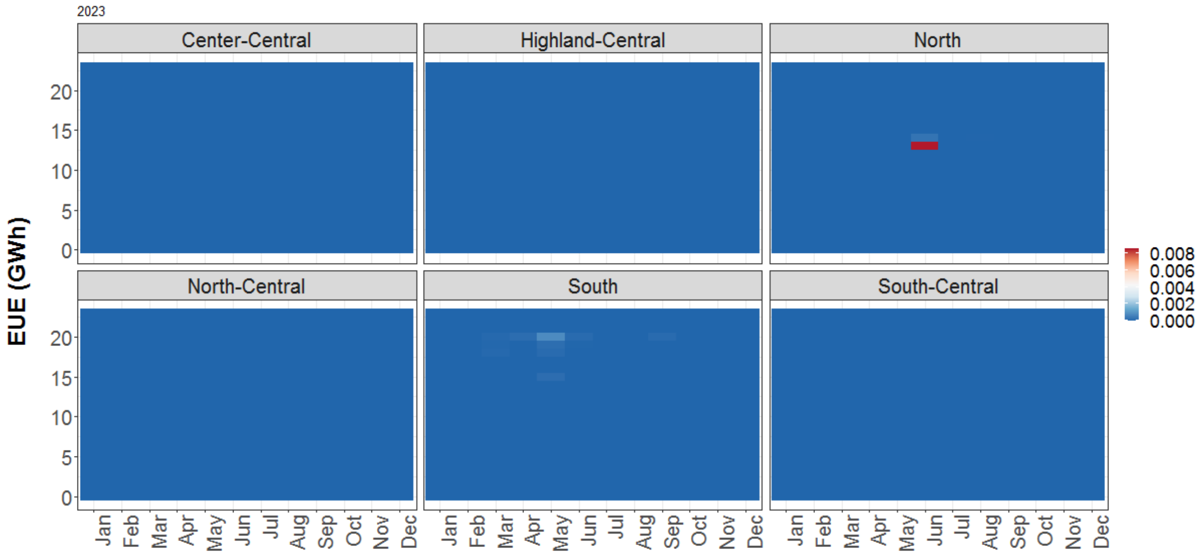


Figure 8-2: Diurnal Pattern of EUE by Region in 2025

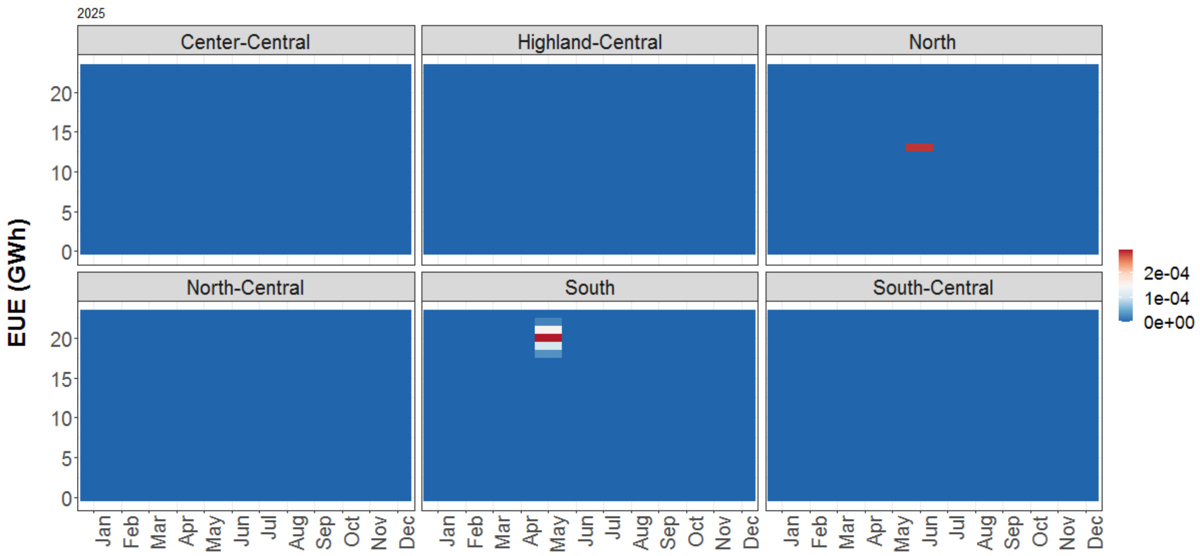


Figure 8-3: Diurnal Pattern of EUE by Region in 2030

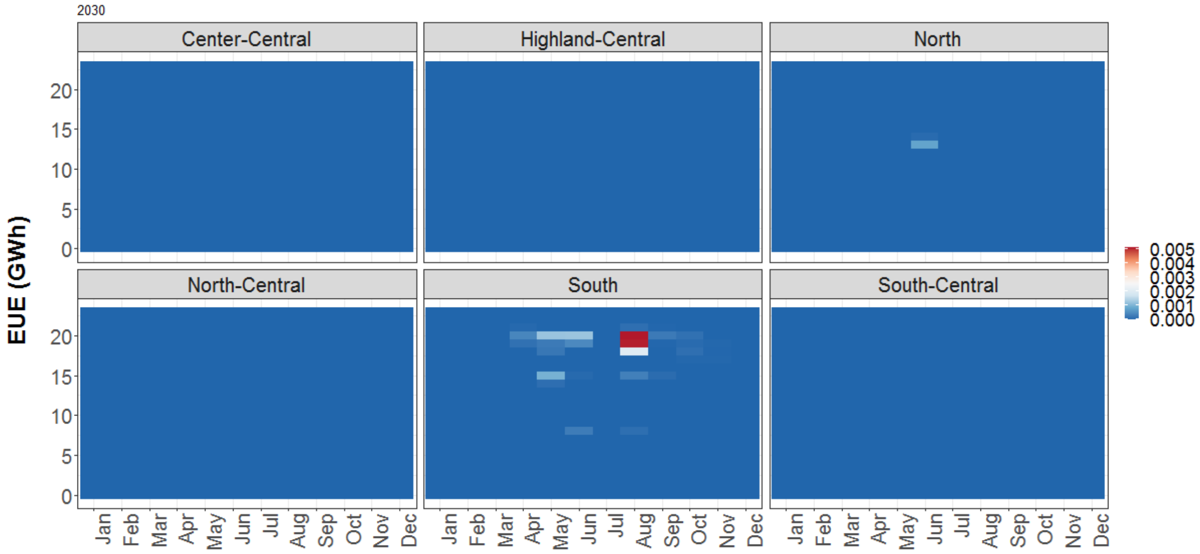


Figure 8-4: Maximum Load Day

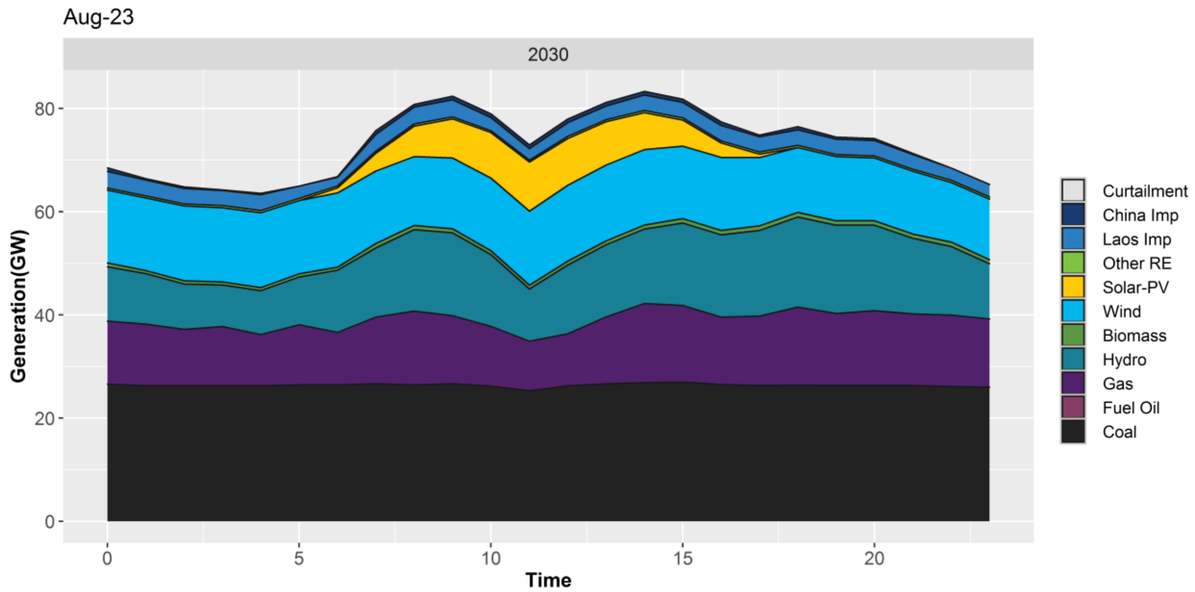


Figure 8-5: Minimum Load Day

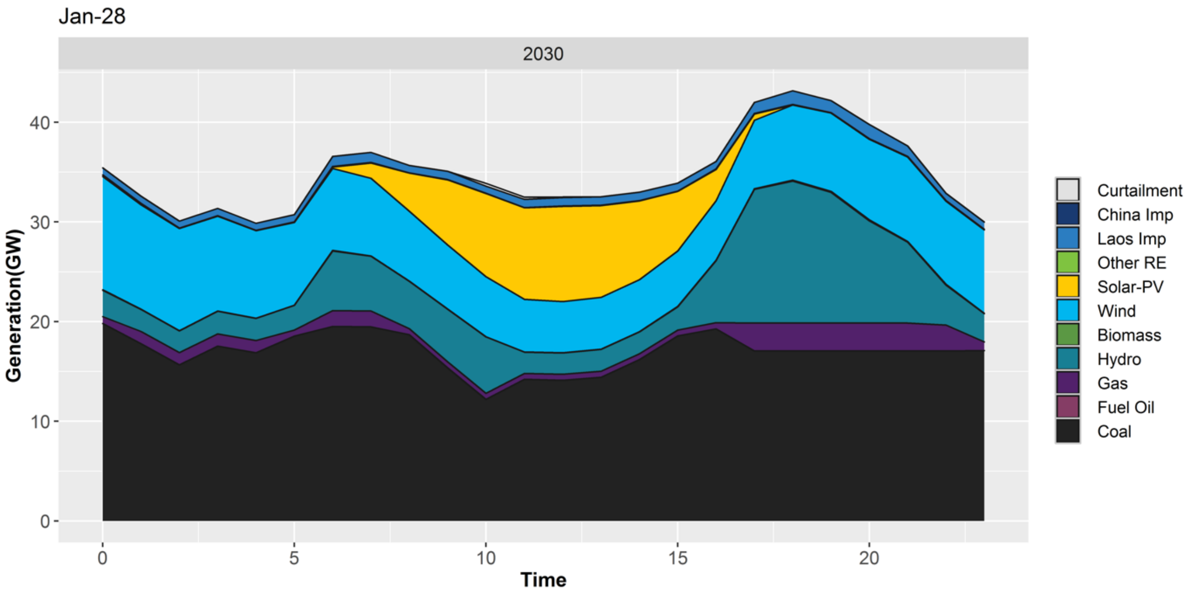


Figure 8-6: Maximum vRE Day

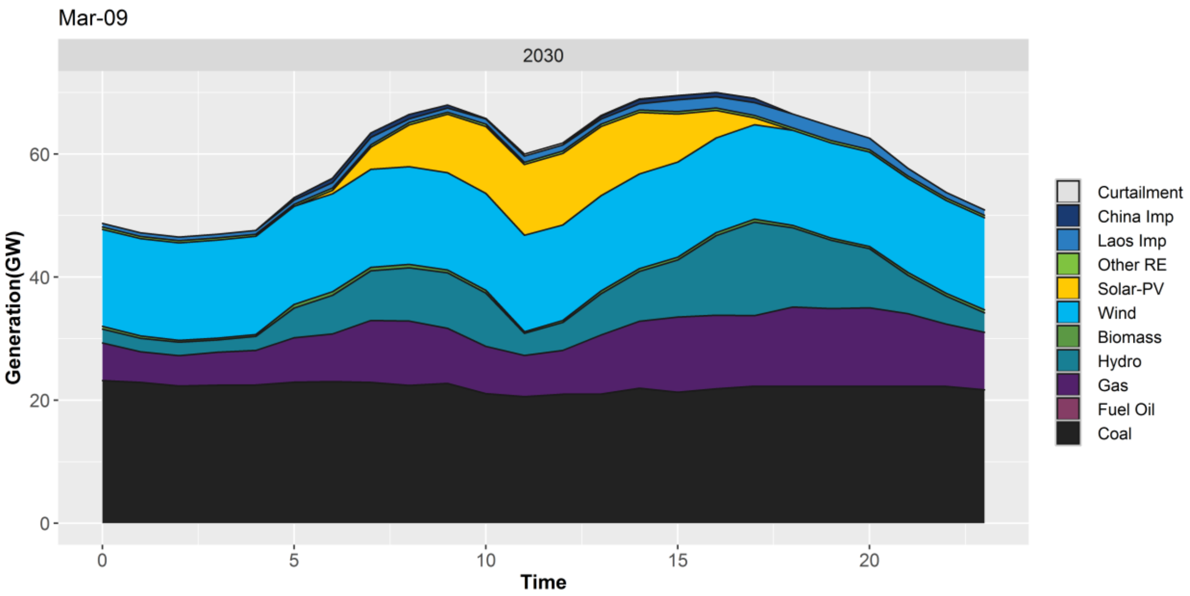


Figure 8-7: Minimum vRE Day

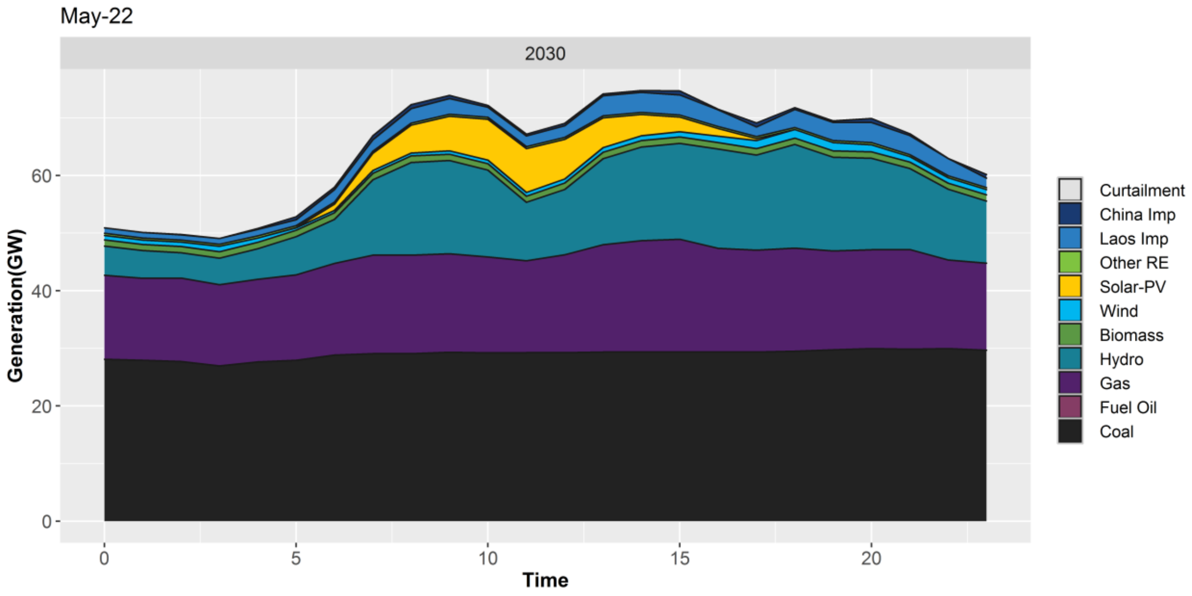


Figure 8-8: Maximum Net Load Day

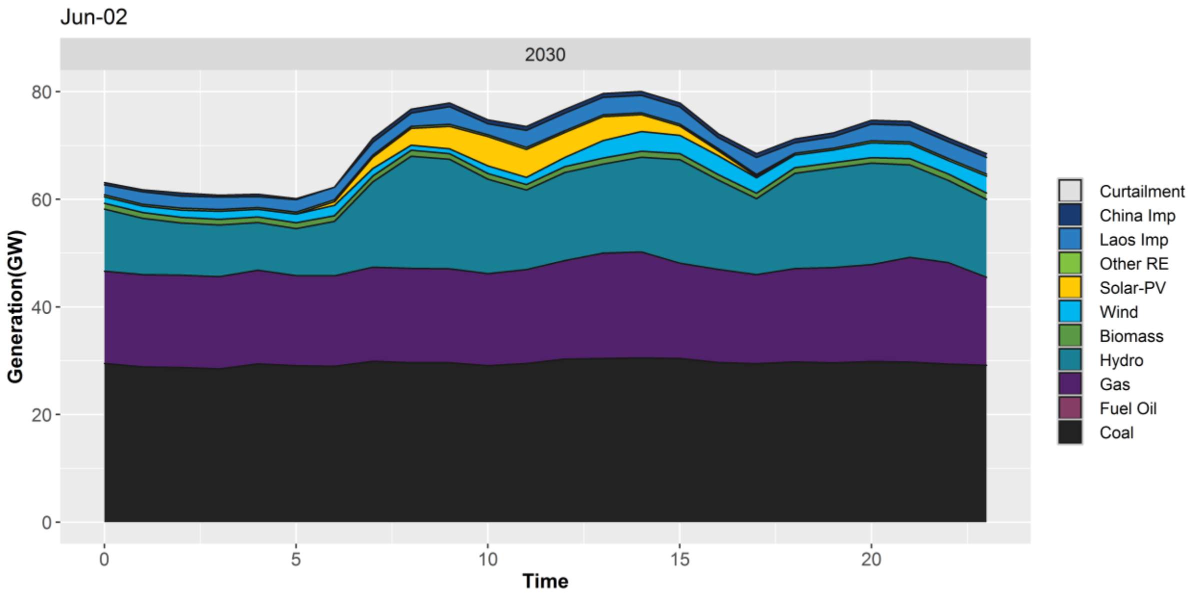


Figure 8-9: Minimum Net Load Day

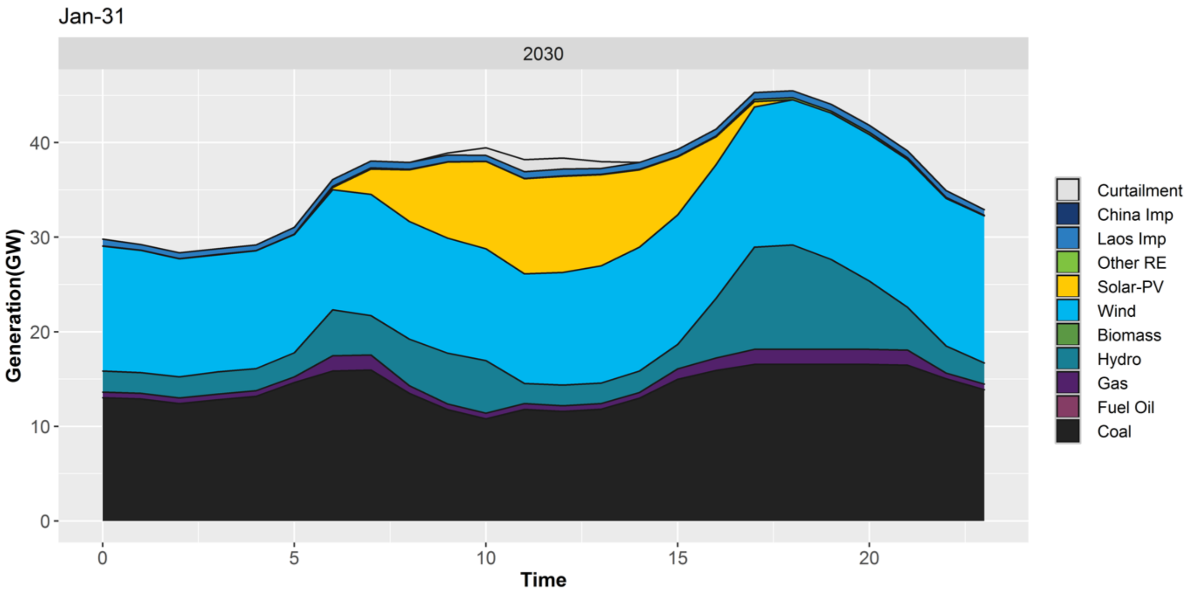


Figure 8-10: Maximum vRE Curtailment Day

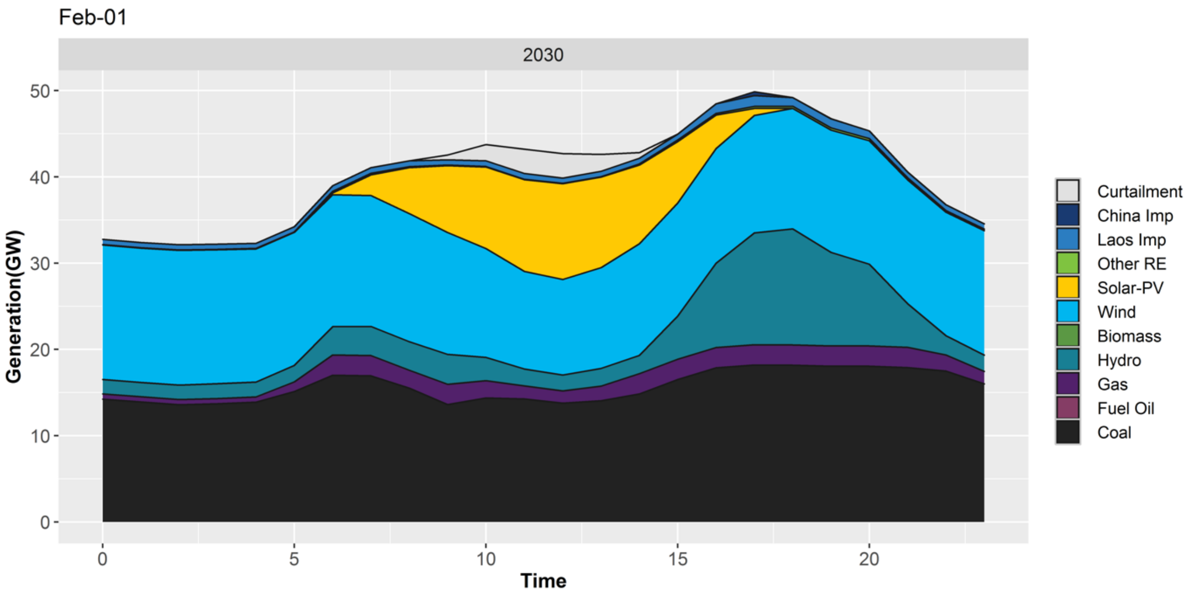


Figure 8-11: Selected Low Demand Dispatch Days in 2030 by Category

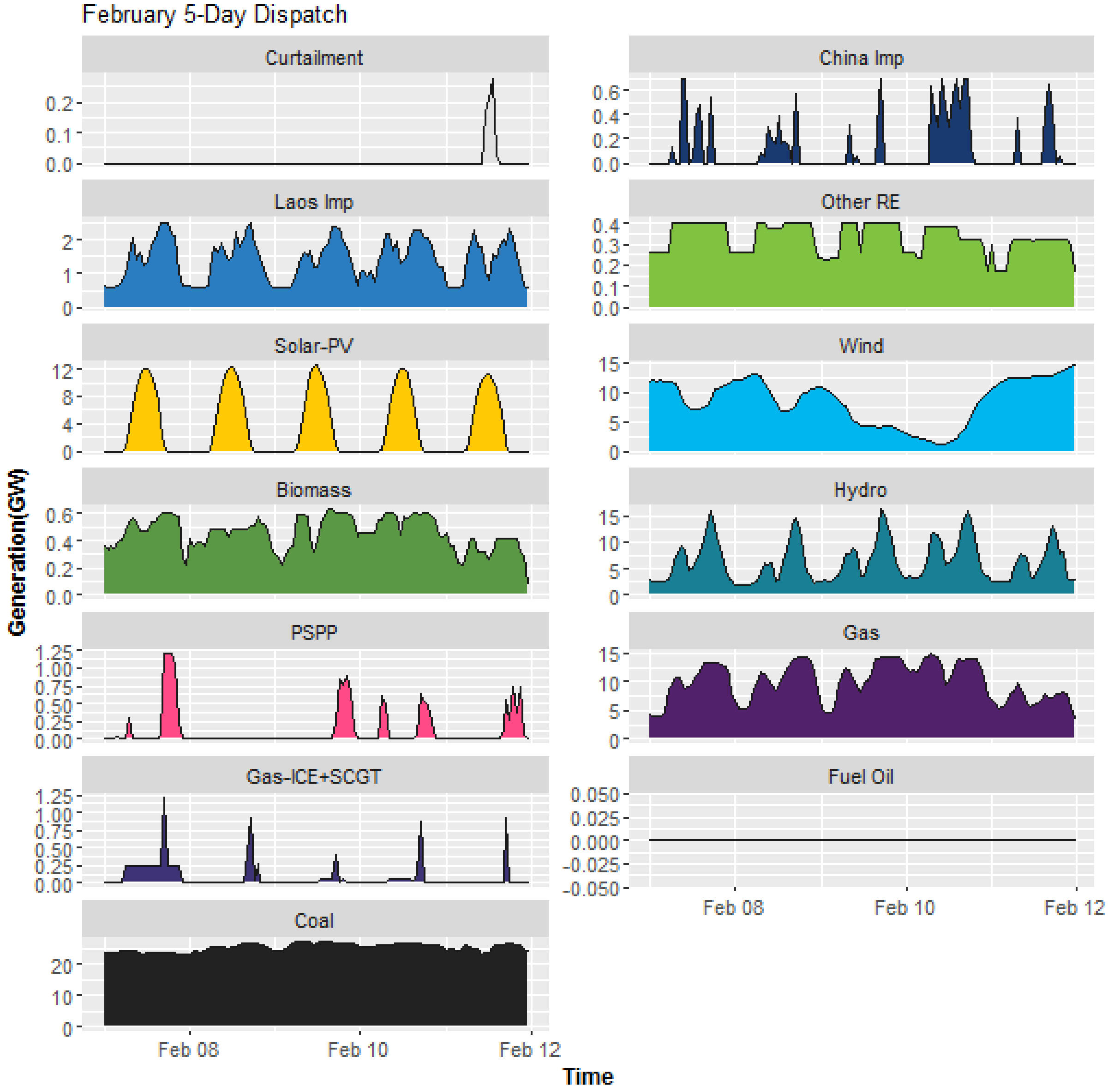
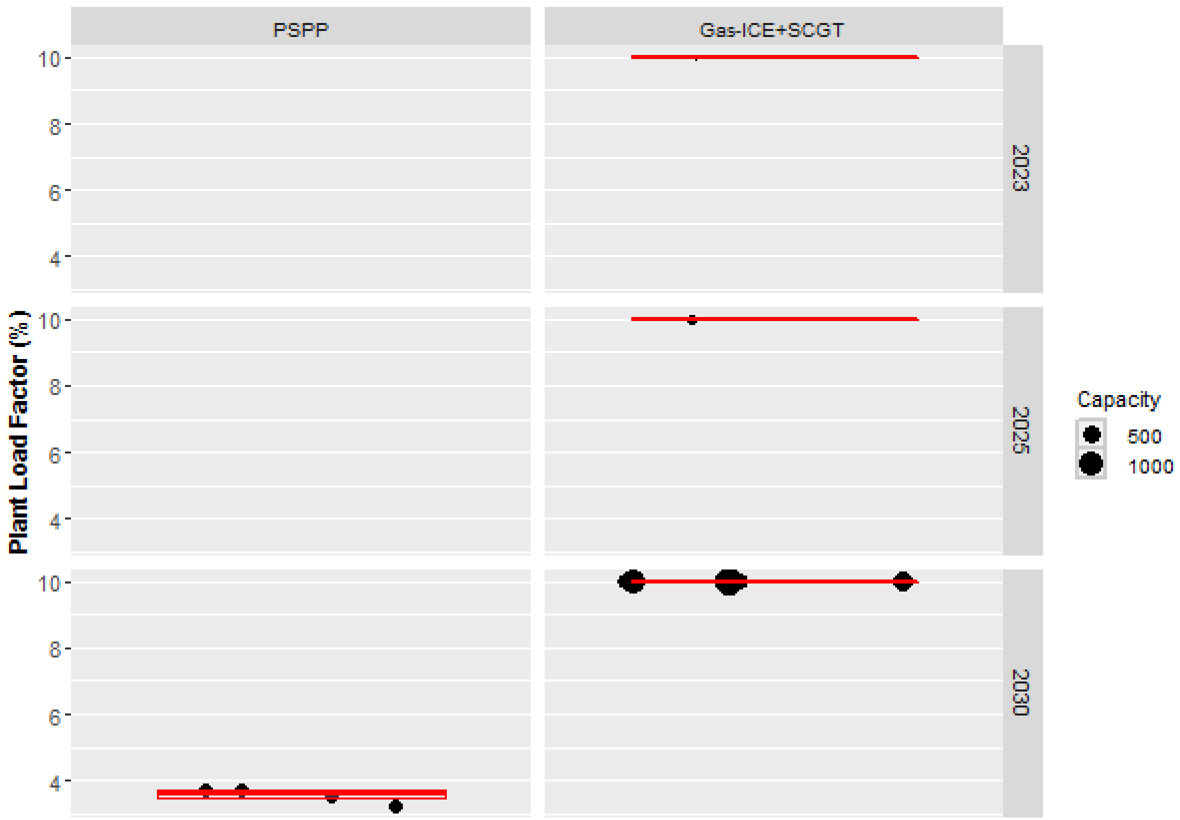


Figure 8-12: Plant Load Factor of PSPP and Gas-ICE+SCGT



9 APPENDIX B

NREL's PRAS simulates a simple transportation network flow model for inter-regional power flow. Unlike the PCM, transmission parameters (e.g., losses, impedance, and detailed line limits) and economic factors (e.g., fuel prices, start/shutdown costs, and coal/gas contracts/offtake limits) are not considered in PRAS. To assess power system's supply adequacy, PRAS draws Monte Carlo samples based on the outages assumed in the model.

In addition to forced outage rates, the following bullet points describe how PRAS represents transmission topology and generation resources in the model.

1. Interface lines are characterized by their import and export limits.
2. Thermal generators (e.g., coal, gas, fuel oil, biomass) are characterized by their maximum capacities.
3. Wind and solar generators are modeled as variable generation resources with hourly rating profiles based on geographic locations.
4. Small hydro generators, which are modeled as run-of-the-river with rating factors in the PCM, are also treated as variable generation resources.
5. Large hydro generators are also characterized by their maximum capacities. Because they are connected to long-term storages, they are treated as energy-limited resources constrained by the natural inflow and energy capacity (or volume) of the storages where they are connected.
6. Pumped storage hydro generators and battery storages are treated as firm capacities with 100% capacity and capability to charge and discharge energy.

Temporal effects are respected for large hydro generators, pumped hydro generators, and battery storages. The available generation capacity, charge capacity, and discharge capacity of these generation resources at the current period are determined from the previous period.