ENERGY TRANSITION PARTNERSHIP
Powering Prosperity and Enabling Sustainability in South East Asia

REPORT

Accelerating Clean Energy Scenario in the Philippines

Deliverable 5: Clean Energy Scenario Investment Plan

29 April 2026

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UNOPS · AFD Agence Française de Développement · Federal Ministry for Economic Affairs and Climate Action · Department for Energy Security & Net Zero · Environment and Climate Change Canada / Environnement et Changement climatique Canada · Australian Government Department of Climate Change, Energy, the Environment and Water · Children's Investment Fund Foundation · Sequoia Climate Foundation

Version History

Version	Date	Change
V01d	20 October 2025	Initial Draft
V02b	19 December 2025	Addresses UNOPS feedback
V03b	29 January 2026	Addresses UNOPS feedback and minor edits
V04a	4 April 2026	Removed coal retirement schedule
V05b	29 April 2026	Minor fixes and edits

This report is developed by IES, PTERRA & NCL as part of Southeast Asia Energy Transition Partnership's ACES project.

Disclaimer

Acronyms

ACES	Accelerated Clean Energy Scenario
ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
BIR	Bureau of Internal Revenue
CES	Clean Energy Scenario
CNP	Cebu-Negros-Panay
CREZ	Competitive Renewable Energy Zone
CTS	Cable Termination Station
DER	Distributed Energy Resource
DOE	Department of Energy
ERC	Energy Regulatory Commission
ETP	Energy Transition Partnership
HVDC	High-Voltage Direct Current
LA	Lanao Area
LCOE	Levelised Cost of Energy
LNG	Liquefied Natural Gas
LVIP	Luzon – Visayas Interconnection Project
MVA	Mega Volt-Amperes
MVAR	Mega Volt-Amperes reactive
MVIP	Mindanao – Visayas Interconnection Project
MW	Mega Watt
NCMA	North Central Mindanao Area
NEMA	Northeastern Mindanao Area
NGCP	National Grid Corporation of the Philippines
NREL	National Renewable Energy Laboratory
NWMA	Northwestern Mindanao Area
OSW	Offshore Wind
PEP	Philippine Energy Plan
PDP	Philippine Development Plan
PHP	Philippine Peso
PGC	Philippine Grid Code
REZ	Renewable Energy Zone
SEMA	Southeastern Mindanao Area
SWMA	Southwestern Mindanao Area
TDP	Transmission Development Plan
TransCo	National Transmission Corporation
UNOPS	United Nations Office for Project Services
USAID	United States Agency for International Development
USD	United States Dollar
VRE	Variable Renewable Energy

Glossary of Terms

Term	Definition
Carbon Price	An assumed or implicit cost applied to carbon dioxide emissions to reflect policy and regulatory impacts.
Clean Energy Scenarios	Planning scenarios that assume high uptake of renewable or low-emissions generation and supporting infrastructure consistent with more ambitious decarbonisation pathways.
Curtailment	The reduction of available electricity generation due to network constraints, system security limits or oversupply conditions. Curtailment in the report specifically refers to variable renewable energy sources.
Flexible Transmission	Transmission projects that are only needed to support specific (not all) generation scenarios.
Levelized Cost of Energy	The average cost per unit of electricity generated. The cost includes capital, operating, fuel and financing costs for generation and transmission assets, and any shortfall costs in relation to unmet load.
Net Present Value	The present value of projected costs and benefits over a horizon discounted to reflect the time value of money.
Robust Transmission	Transmission projects that form the planned transmission backbone upgrades, necessary across all generation scenarios.
Sunk Cost	A cost that has already been incurred or committed to and cannot be recovered or reversed. It is therefore excluded from forward-looking investment decisions.
Transmission Planning Attributes	Transmission planning criteria that serve as guide for determining upgrades for transmission development, which are defined at the start of the transmission planning process. These attributes typically start with reliability as the top priority, followed by cost efficiency.

Table of Contents

Executive Summary

The intention of the broader Accelerating Clean Energy Scenarios capacity development and mentoring exercise is aimed at developing the skills needed to determine the investments needed for the country's transition to clean energy. Instead of traditional planning where generation and transmission planning is conducted sequentially, the co-optimization or integrated approach assesses power plants and grid upgrades jointly to form the long-term development plans. The generation portion of the Philippines Energy Plan Clean Energy Scenarios identifies the most economical combination of renewable energy, nuclear power, and flexible resources, while the transmission portion outlines the infrastructure and funding needed to connect these resources and maintain secure grid operations. The result is a clear direction for long-term investments that support the clean energy scenarios.

This report relates to Deliverable 5: Clean Energy Scenario Investment Plan, which sets out a long-term planning document divided into five-year investment periods to guide near-term decisions. This stepwise approach ensures that near-term investments align with the overall strategic plan and that transmission infrastructure development progresses in step with new generation capacity and rising demand.

Modelled Scenarios

The Department of Energy (DOE) released the Philippine Energy Plan 2023-2040 (PEP) in 2024. The document provides clear development paths for the Philippine energy and underlying power sector across various scenarios. The purpose is to guide the country's energy transition towards increased renewables generation. The central policy driver of the country's transition is based on increasing renewable energy generation in the supply mix to over 35% by 2030 and over 50% by 2040, while gradually reducing fossil fuel reliance.

This project builds on the Philippine Energy Plan, further developing the modelling to explore additional details and aspects of power system planning that become increasingly relevant under more ambitious decarbonisation objectives. It aims to support policymakers in understanding the impacts of the coal moratorium policy, alternative clean energy scenarios, and the displacement of fossil fuels on energy supply and system costs.

The energy development outlook explored in the Philippine Energy Plan is anchored on two scenarios: the Reference Scenario (REF) and the Clean Energy Scenario. The Reference Scenario assumes the continuation of current energy policies, while the Clean Energy Scenario reflects more ambitious renewable energy targets within the planning horizon. The way these scenarios translate into power sector development pathways is summarised in Table 1 below. The Clean Energy Scenario is further split into alternative pathways (CES1 and CES2), differentiated by the amount of offshore wind. Key features of these scenarios are outlined below:

- Single demand projection common to all scenarios. Forecast scheduled (or grid) demand will increase by more than threefold by 2050.
- Nuclear and offshore wind comprising a large share of the overall supply mix in the Clean Energy Scenarios.
- Leveraging Philippines' vast renewable energy resource to achieve ambitious emissions reduction targets under the Clean Energy Scenarios.

Table 1 Scenario Definitions

Scenario	REF	CES 1	CES 2
Description	Existing policies remain in place to meet the threefold increase in electricity demand by 2050[1]	Supply-side policies targeting nuclear and offshore wind deployments, with an added 60% emissions reduction target.	More ambitious OSW targets and a higher carbon emissions reduction of 80%.
Demand	PEP annual energy and peak demand forecast (same across all scenarios). Distributed energy resources and demand-side policies not modelled.[2]		
Technology Development	Deployment of clean energy technologies remains consistent with the current policies.	REF case with minimum addition of 19 GW offshore wind and nuclear capacity of 1200 MW by 2032, 2400 MW by 2035, and 4800 MW by 2050.	
Policy Frameworks	Existing Policies (primarily towards meeting renewable energy targets).	REF case with emissions reduction policies and coal retirement framework to facilitate orderly retirements (as required). Small-scale generation and demand-side policies not modelled.	
Infrastructure and Grid Modernisation	Transmission network and CREZ transmission investment and to accommodate higher levels of utility-scale renewable energy.		
Emission Reduction Targets	None, other than what is implied through renewable energy targets.	60% reduction in emissions against the Reference Case by 2050.	80% emissions reduction against the Reference Case by 2050.
Curtailment	Allow for up to 15% curtailment across all solar, onshore and offshore wind projects.[3]		

Capacity Development

The Clean Energy Scenarios are presented for comparison against the Reference Case. The primary modelling differences in these scenarios are the inclusion of 4.8 GW of nuclear capacity by 2050 and the implementation of explicit offshore wind policy targets, set at 19 GW and 50 GW by 2050 for CES1 and CES2, respectively. As shown in Figure 1, the inclusion of nuclear and the substantial build-out of offshore wind under CES1 and CES2 displace much of the solar and onshore wind

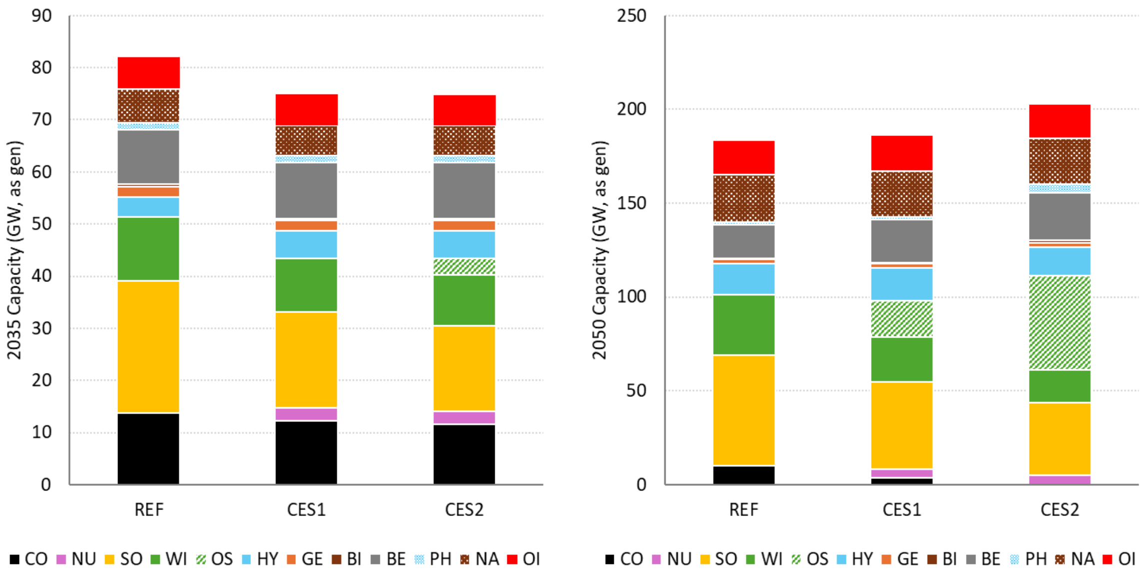
[1] Exception is the change to the current 'priority dispatch' arrangements aimed at minimising curtailment for certain generator types.

[2] Small-scale generation and demand-side management measures were not explicitly modelled in the present analysis. Nevertheless, it should be noted that the Philippines already has an established policy and regulatory framework promoting energy efficiency and conservation, particularly under Republic Act No. 11285 or the Energy Efficiency and Conservation Act, its Implementing Rules and Regulations, and the National Energy Efficiency and Conservation Plan and Roadmap.

[3] Assumes priority dispatch is retained for all other eligible generation types but allows for higher levels of curtailment for future developments. Refer to the D4 'Report on BAU and Clean Energy Scenarios' for a more detailed discussion.

capacity that would otherwise be developed under the Reference Case. The solar PV and onshore wind development trajectories diverge from the Reference Case around 2032 with the commissioning of the first nuclear units, and from 2036 and 2041 respectively as offshore wind capacity expands. Most of the additional renewable capacity is developed in Philippines' renewable energy zones and requires supporting transmission investment.

Figure 1 Capacity Development Comparison



SO = solar, WI = onshore wind, OS = offshore wind, BE = BESS, PH = pumped hydro, OC = open cycle gas turbines, CC = combined cycle gas turbines, CO = coal, HY = hydro, BI = biomass, GE = geothermal, NA = natural gas, OI = oil.

Carbon Emissions

Total carbon emissions under CES2 decrease by approximately 75% relative to the Reference Case by 2050, while CES1 achieves a reduction of around 53% (Figure 2). Emission levels between the scenarios begin to diverge from 2032, coinciding with the commissioning of the first nuclear units and the commencement of offshore wind developments in CES2 from 2036. The rate of emissions reduction slows in the final five years across the clean energy scenarios, while in the Reference Case, emissions rise relative to 2026 levels due to the tripling of demand by 2050.

On a grid intensity basis (Figure 3), the results show a rapid reduction across all scenarios, reflecting the increasing share of low-emission generation technologies. The decline is most pronounced in CES2, followed by CES1, consistent with the higher levels of nuclear and offshore wind development relative to the Reference Case.

Figure 2 Total System Emissions Comparison

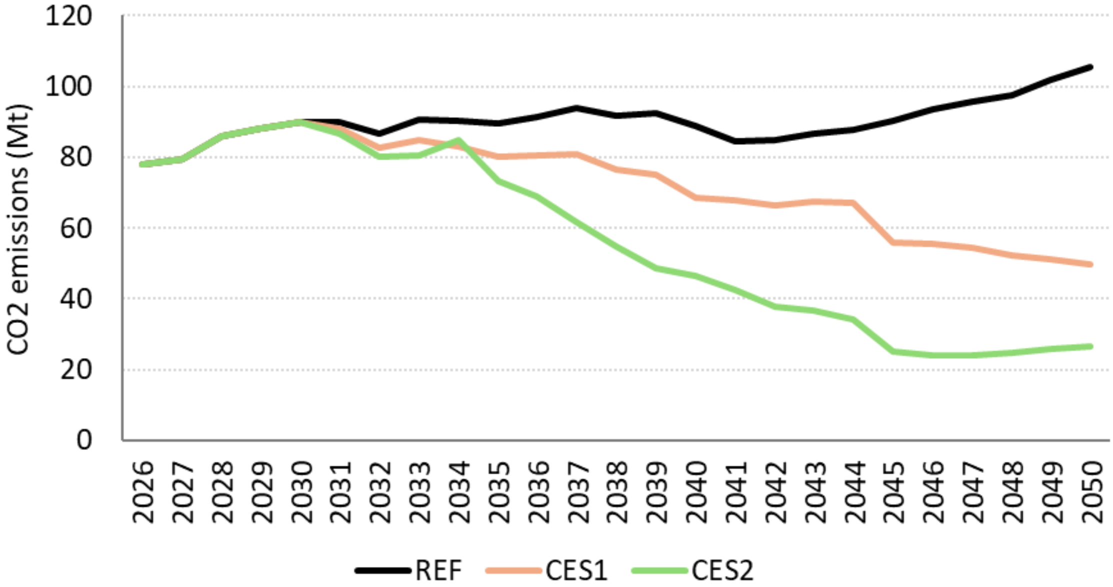
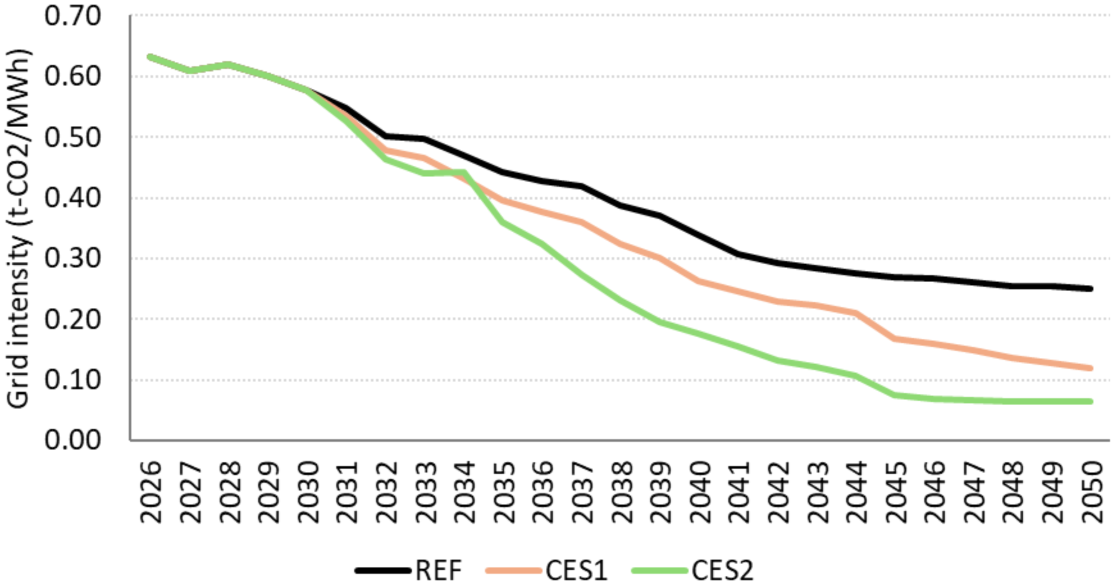


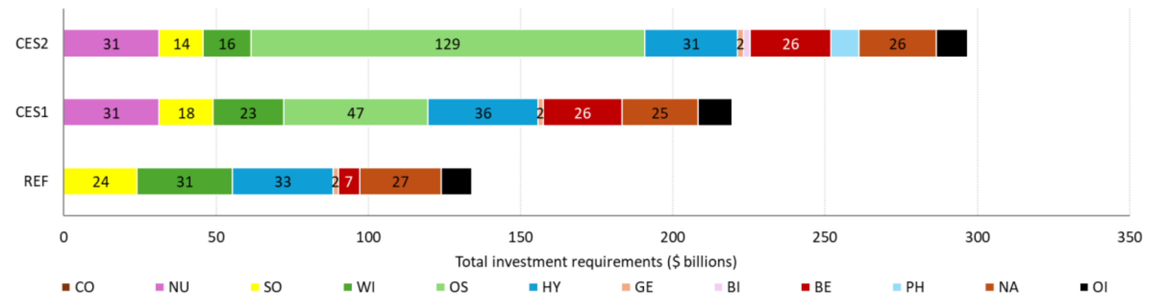
Figure 3 Grid Emissions Intensity Comparison



Generation Investment Plan

The generation investment requirements differ markedly across the Reference Case and Clean Energy Scenarios (CES1 and CES2). By 2050, total generation investment in CES2 reaches $296 billion, more than double the Reference Case ($134 billion), while CES1 requires $219 billion (Figure 4). The divergence begins as early as 2035, primarily due to the introduction of nuclear units ($31 billion by 2050) and significant investment in offshore wind ($129 billion under CES2).

Figure 4 Generation Investment Comparison

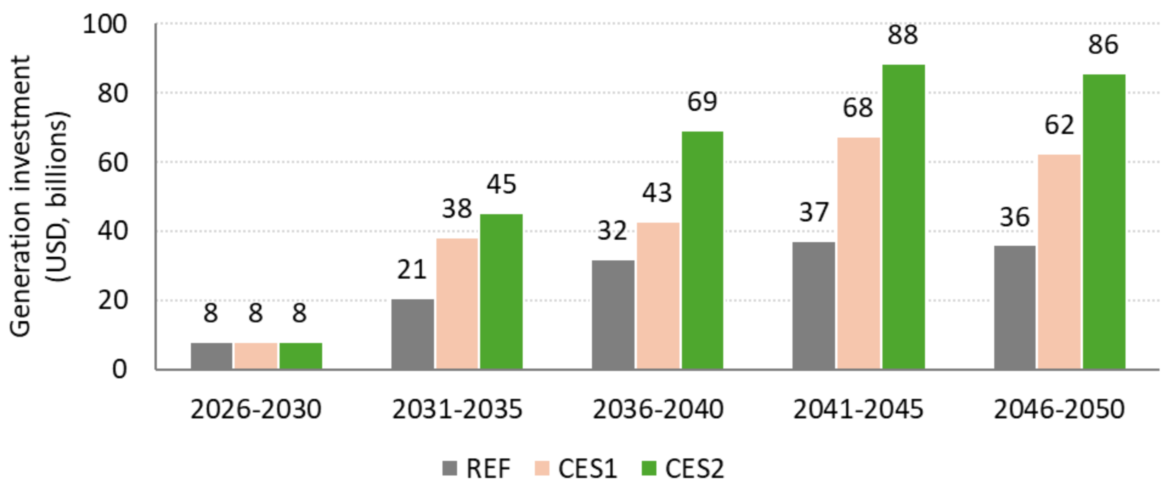


SO = solar, WI = onshore wind, OS = offshore wind, BE = BESS, PH = pumped hydro, OC = open cycle gas turbines, CC = combined cycle gas turbines, CO = coal, HY = hydro, BI = biomass, GE = geothermal, NA = natural gas, OI = oil.

Investment timing is a key driver of these differences. All scenarios require substantial early investments to support renewable deployment and system expansion, with solar, wind, and battery projects needing around $6 billion by 2030 towards the 2040 50% renewable share target and address reserve shortfalls in the near-term. Sustained investment continues throughout the 2030–2050 period to meet demand growth and support system reliability. The Reference Case requires an average of $6 billion per year in generation investment, compared to $11 billion and $14 billion per year for CES1 and CES2, respectively.

CES1 and CES2 involve additional capital-intensive technologies. Nuclear capacity demands $15.5 billion per 2,400 MW across two deployment periods (2031–2035 and 2041–2045). Offshore wind development drives substantial investment in CES1 starting 2041 ($50 billion over 2041–2050) and CES2 ($35 billion per 5-year period in Luzon from 2036, plus $10 billion in the Visayas). CES2 also requires significant investment in battery energy storage (around $6 billion per 5-year period) and long-duration pumped hydro ($9 billion in Luzon).

Figure 5 Generation Investment Comparison (5-year Snapshots)



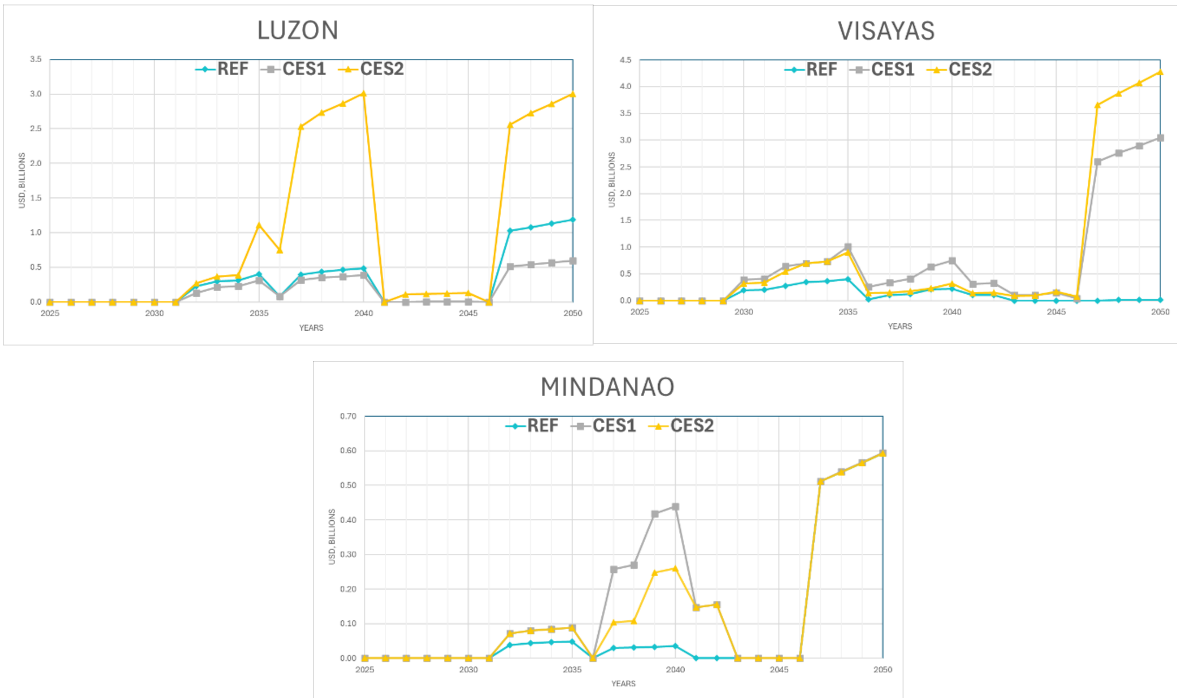
The Clean Energy Scenarios also include costs associated with early coal retirements, potentially up to $3.6 and $9.1 billion under CES1 and CES2. The overall CES1 and CES2 benefits are evident in the much lower emissions relative to the Reference Case. Assuming a carbon price of $200/t-$CO_2$, CES2 generates a carbon cost saving of $170 billion (undiscounted), which roughly offsets the generation cost difference between the REF and CES2 scenarios, highlighting the economic and environmental rationale for pursuing a more sustainable energy pathway.

Transmission Investment Plan

In the study, which considers the economic generation dispatch, the horizon plan supports the transition from the REF scenario to CES 2 in the Luzon and Visayas grids via an investment plan that requires about 4 to 5 times that of the REF scenario. For Mindanao, the investment needed under CES 2 is roughly twice that of the REF scenario. The economic dispatch results indicate that the Mindanao grid can achieve a cleaner energy transition with relatively lower additional investment.

The disbursement schedule for the sample plan shows that investment activities increase gradually from the early years to the medium-term period, as transmission reinforcements must be completed to keep pace with new generation entry and growing demand (Figure 6). Consequently, the medium term reflects the highest concentration of investments. Beyond 2040, investment spending is expected to peak again due to the required series of HVDC links that will support the growing power exchange among the Luzon, Visayas, and Mindanao grids.

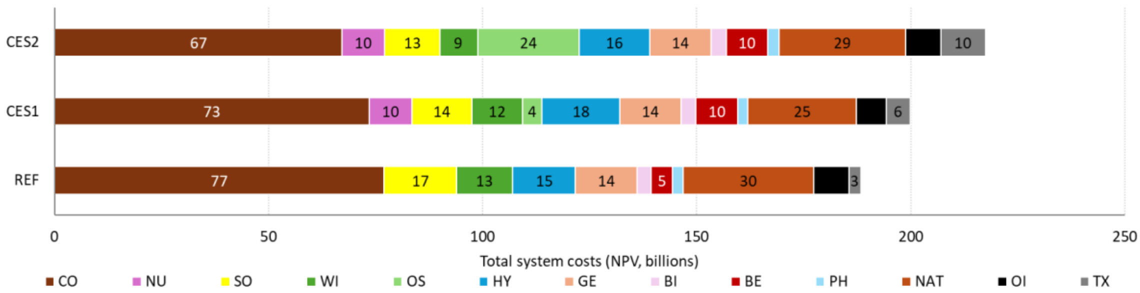
Figure 6 Annual Transmission Investment Comparison



Levelised Cost of Energy

The levelised cost of energy (LCOE), which includes generation and transmission costs, diverges significantly between the Reference case and Clean Energy Scenarios. The reasons for the differences can be seen in the net present value of total system costs, presented in Figure 7. The main contributors are: (a) significantly higher coal generation costs from maintaining the coal fleet to the end of its technical life, (b) $10 billion in nuclear costs associated with the 4.8 GW nuclear target, (c) up to $24 billion in offshore wind costs, and (d) higher transmission and battery investment costs. Ultimately, the results highlight the cost trade-off between sustainability and cost, assuming reliability and security are maintained.

Figure 7 System Cost Comparison (Net Present Value)



Note: Net present value calculated as of 2026 at a discount rate of 10% pa. SO = solar, WI = onshore wind, OS = offshore wind, BE = BESS, PH = pumped hydro, OC = open cycle gas turbines, CC = combined cycle gas turbines, CO = coal, HY = hydro, BI = biomass, GE = geothermal, NA = natural gas, OI = oil.

The planning scenarios demonstrate the impact of various policy directions on the future development of the power system. The Reference Case assumes a continuation of current policies and least-cost generation expansion, resulting in a balanced mix of conventional and renewable technologies. Conversely, the Clean Energy Scenarios (CES1 and CES2) investigate ambitious decarbonisation pathways that prioritise sustainability and emissions reduction through policy-led investments in offshore wind and nuclear capacity.

These scenarios highlight the trade-offs between system complexity, sustainability, and cost. While the Clean Energy Scenarios deliver significant emissions reductions, they require substantially higher investment. The integration of nuclear, offshore wind, and high levels of VRE necessitates expanded transmission networks, storage development, and coordinated grid operations to ensure reliability and minimise curtailment.

The scenarios examine the effects of accelerated coal retirements and increased renewable penetration on system operations. As VRE becomes the dominant power source, system flexibility, inter-regional transmission, and long-duration storage emerge as critical factors for security of supply and efficient dispatch. These dynamics underscore the necessity of coordinated CREZ development and the strategic timing of regional infrastructure investments.

Total costs rise as the generation scenario composition changes the Reference Case to Clean Energy Scenarios. This trend reflects the higher proportion of renewable energy, which increases loading on primary transmission corridors. Furthermore, the substantial MW interchange between grids in the clean energy pathways contributes to elevated infrastructure expenditure.

Conclusion

Power system planning is critical in ensuring the development is aligned to the broader energy objectives. Government agencies, such as the DOE and Energy Regulatory Commission, need this planning work to inform regulatory actions and policy decisions. The modelling framework covered in this report allows these bodies to evaluate policy robustness, project readiness and approve expansion programmes, ensuring that both generation and transmission developments are coordinated under a unified national strategy. By providing a consistent basis for oversight, the plan facilitates the systematic alignment of infrastructure goals with national energy objectives.

The investment plan further serves as a guide for all stakeholders in the timely and efficient operationalisation of transmission projects. While the private sector drives the majority of generation investments, particularly regarding flexible resources and renewable energy, their commercial decisions on the location and timing of new capacity ultimately also depend on transmission reinforcements. Consequently, the plan acts as a vital link between private sector activity and the necessary expansion of the grid.

Overall, the investment plan outlines project timelines, projected costs, and the required cooperation between government entities to reform market incentives for least-cost development. It provides a common reference point for decision-making in both generation and transmission planning, ensuring that infrastructure is deployed efficiently. This synchronised approach ensures that investments are made at the appropriate time to support the country's transition towards cleaner energy.

1 Introduction

1.1 Project Background

Intelligent Energy Systems Pty Ltd (IES) and Nel Consulting Limited (NCL) have been selected by UNOPS to carry out the project titled "Accelerating Clean Energy Scenario in the Philippines". The project is implemented under the UNOPS Southeast Asia Energy Transition Partnership. The expected long-term outcomes from this project are:

- Increase in renewables and readiness for impacts of fossil fuel displacement.
- Enhanced capability in generation expansion and transmission expansion planning by the government to support policymaking, clean energy target setting, and investment promotions.
- Coordinated upgrading of the transmission network with the development of power generation plants, ensuring that renewable energy plants can readily connect to the grid.
- Increased renewable energy ambition while promoting energy security, reliability, and affordability.

1.2 ETP Role in Supporting the Energy Sector Transition in the Philippines

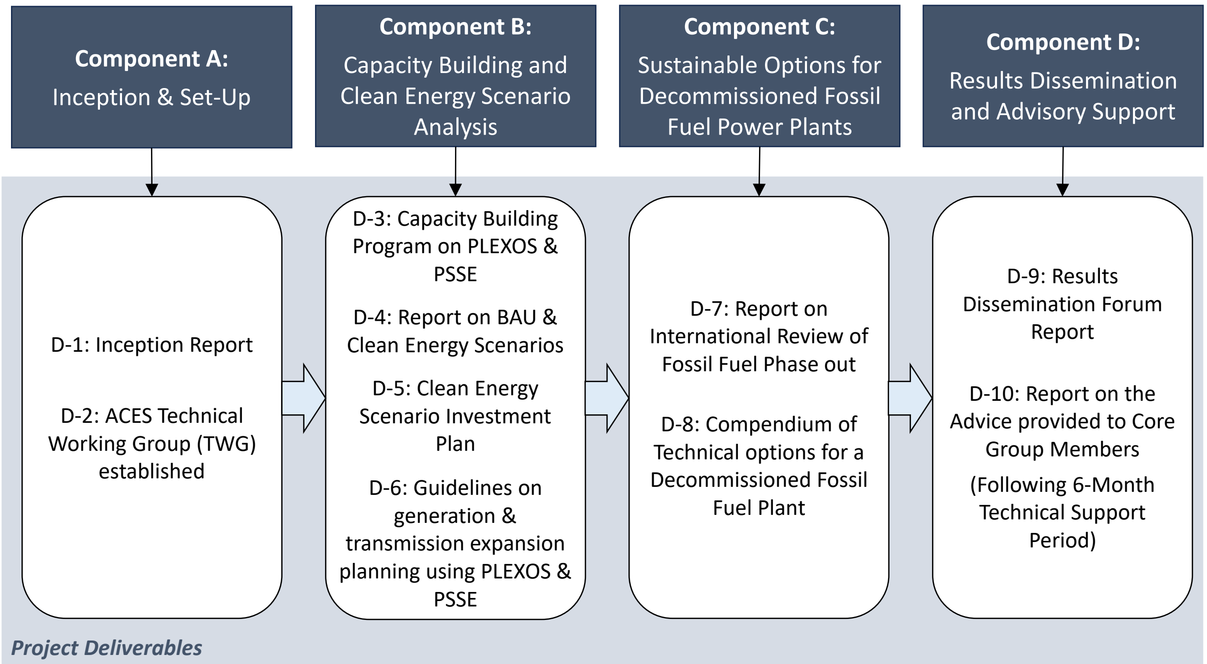
ETP unites philanthropies and governments to collaborate with regional partners. It is in favour of the switch to contemporary energy systems that can guarantee environmental sustainability, energy security, and economic prosperity all at once. With the first three agreements signed with Indonesia, the Philippines, and Vietnam; the ETP operates in Southeast Asia to help accomplish the goals of the Paris Climate Agreement and the UN's Sustainable Development Goals (SDGs). Four interconnected strategic engagement pillars that are well matched to overcome the obstacles to energy transition form the foundation of ETP's approach. These include:

- Aligning policies with climate commitments,
- Reducing the risk associated with investments in renewable energy and energy efficiency,
- Expanding smart grids, and
- Just transition.

1.3 Scope of Work

The Philippines is aggressively working towards a clean energy scenario (CES) target of 50% share of renewables in the power generation mix by 2040. The project focuses on understanding how the CES displaces fossil-based plants, particularly coal-fired power plants, and analyses the impact on energy supply, tariffs, and grid reliability through strategic integrated power generation and transmission planning. It develops capabilities in simulating medium- and long-term power and transmission scenarios using modelling software where results support policy making, target setting, and investment promotions. The project promotes an integrated planning approach by aligning long-term power generation development plans with transmission planning. This report, Deliverable 5, presents the investment requirements for the Reference Case and Clean Energy Scenarios. It forms one of four deliverables in Component B as indicated in Figure 8.

Figure 8: Components and Deliverables

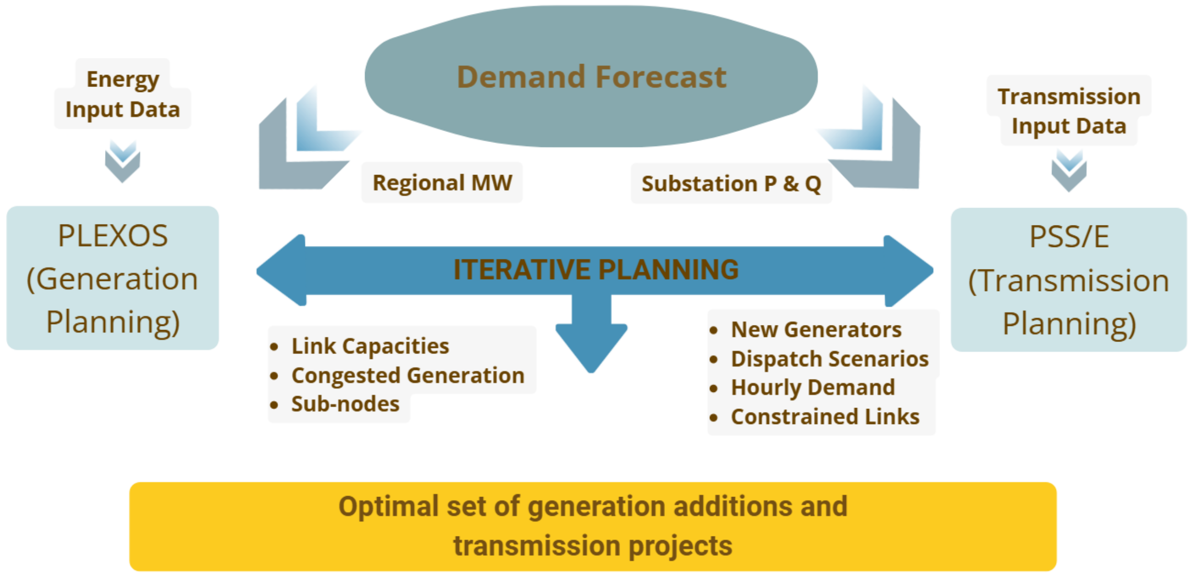


1.4 Integrated Power Generation and Transmission Planning

Power generation and transmission planning over the medium-term and long-term collectively support the policies, decisions, strategies, target setting, and determination of investment programs and financing requirements for the industry. In this project, two separate software tools are used: PLEXOS for least-cost generation planning and PSS/E for transmission planning.

The overall approach for the integrated power generation and transmission planning is illustrated in Figure 9. Although the generation and transmission planning are conducted separately, the two processes are linked through an iterative exchange of outputs. The least-cost generation expansion planning outputs from PLEXOS are used to identify suitable system snapshots, which are then assessed in PSS/E using a more detailed model to determine whether the transmission network operates within the confines of the 2016 Philippine Grid Code (PGC) standards. The transmission network modelling and assessments may then identify the need for additional investments or measures to ensure power system stability and reliability. The findings are subsequently incorporated into PLEXOS for additional simulations. This iterative process is repeated until the outcomes converge on a solution that is both economically viable and technically robust.

Figure 9 Integrated Power Generation and Transmission Planning



1.5 Structure of Report

The Clean Energy Scenario Investment Plan report (Deliverable 5) is structured as follows:

- Section 1 introduces the project and Deliverable 5 objectives.
- Section 2 presents a summary of the scenario modelling outcomes from the BAU and Clean Energy Scenarios Report (Deliverable 4).
- Section 3 details the generation investment plan.
- Section 4 details the transmission investment plan.
- Section 5 presents the levelised cost of energy outcomes.
- Section 6 summarises the key findings and conclusion.

1.6 Report Notes

The basis of figures quoted in this report, unless otherwise stated, are based on the information listed in Table 2 below. Deliverable 4 refers to the BAU and Clean Energy Scenarios Report and should be read in conjunction with this report.

Table 2 Reporting basis

Type	Basis
Years	Calendar year basis starting Jan to Dec
Capacity and generation (MW & MWh equivalents)	As generated

Type	Basis
Dollars/Philippines Pesos	Real 2024
Demand	Operational demand (as generated basis)[4]
Acronyms used for generation types	SO = solar, WI = onshore wind, OS = offshore wind, BE = BESS, PH = pumped hydro, OC = open cycle gas turbines, CC = combined cycle gas turbines, CO = coal, HY = hydro, BI = biomass, GE = geothermal, NA = natural gas, OI = oil.

[4] Operational demand is defined as native demand minus impacts from rooftop PV, and other non-aggregated embedded generation technologies.

2 Reference Case and Clean Energy Scenarios

The planning scenarios illustrate how different policy directions influence the future development of the power system. The Reference Case represents a continuation of current policies and least-cost generation expansion, reflecting a balanced mix of conventional and renewable technologies aligned with existing trends. In contrast, the Clean Energy Scenarios (CES1 and CES2) explore more ambitious decarbonisation pathways that prioritise emissions reduction and sustainability objectives, supported by policy-led investment in nuclear and offshore wind capacity.

These scenarios provide insight into the trade-offs between cost, sustainability, and system complexity. While the Clean Energy Scenarios achieve substantial emissions reductions, they do so at considerably higher investment costs. The integration of high levels of VRE, offshore wind, and nuclear generation also drives greater reliance on transmission expansion, storage development, and coordinated grid operation to maintain reliability and minimise curtailment.

The scenarios also test the implications of accelerated coal retirements, higher renewable penetration, and emerging technologies on overall system operation. As VRE becomes dominant, system flexibility, inter-regional transmission, and long-duration storage become critical enablers of efficient dispatch and security of supply. These dynamics reflect the increasing importance of planning for coordinated CREZ development and the timing of infrastructure investments across the regions.

2.1 Philippines Energy Plan

The Department of Energy (DOE) released the Philippine Energy Plan 2023-2040 (PEP) in 2024. The document provided clear development paths for the Philippine energy sector as a whole, and underlying power sector across three distinct scenarios. The underlying purpose was to guide the country’s energy transition towards increased renewables generation. The central policy driver of the country’s transition was based on increasing renewable energy generation in the supply mix to over 35% by 2030 and over 50% by 2040, while gradually reducing fossil fuel reliance.

Much of the important groundwork for power system development has already been established through the Philippines Energy Plan framework and associated modelling. This project builds on that foundation, further developing the modelling to explore additional details and aspects of power system planning that become increasingly relevant under more ambitious decarbonisation objectives. It aims to support policymakers in understanding the impacts of the coal moratorium policy, alternative clean energy scenarios, and the displacement of fossil fuels on energy supply and system costs. The project also seeks to enhance evidence-based policy and decision-making by strengthening policymakers’ capability in PLEXOS and PSSE modelling and simulations for low-carbon power sector planning, including transmission planning. In addition, it provides technical options for repurposing, replacing, or disposing of decommissioned fossil fuel plants.

2.2 Scenario Descriptions

The energy development outlook explored in the PEP is anchored on two scenarios: the Reference Scenario (REF) and the Clean Energy Scenario (CES). The Reference Scenario assumes the continuation of current energy policies, while the Clean Energy Scenario reflects more ambitious renewable energy targets within the planning horizon. Although the development objectives extend across the entire energy sector, the power sector is recognised as critical in decarbonising the broader economy. The way these scenarios translate into power sector development pathways is summarised in Table 3 below. The Clean Energy Scenario presented in the PEP is further split into an alternative pathway, differentiated by the amount of offshore wind. Key features of these scenarios are outlined below:

- Single demand projection common to all scenarios. Forecast scheduled (or grid) demand will increase by more than threefold by 2050. This is a significant expansion of the Philippine power system.
- All scenarios focus on grid-supply developments. Small-scale generation and demand-side management measures were not explicitly modelled in the present analysis. Nevertheless, it should be noted that the Philippines already has an established policy and regulatory framework promoting energy efficiency and conservation, particularly under Republic Act No. 11285 or the Energy Efficiency and Conservation Act, its Implementing Rules and Regulations, and the National Energy Efficiency and Conservation Plan and Roadmap.[5]
- Nuclear and offshore wind comprising a large share of the overall supply mix in the Clean Energy Scenarios.
- Leveraging Philippines' vast renewable energy resource to achieve ambitious emissions reduction targets under the Clean Energy Scenarios.
- Key assumptions relating to fuel costs, generator and transmission build costs are also held constant across all scenarios.

Given the focus on capacity development, the Clean Energy Scenarios incorporate more ambitious emissions reduction targets. The rationale for this approach is to ensure that the modelling explores more challenging dynamics that are likely to emerge under conditions of higher renewable generation. This provides policymakers and system planners with insights into the complexities of operating and expanding a power system under accelerated decarbonisation pathways.

Table 3 Scenario Definitions

Scenario	REF	CES 1	CES 2
Description	Existing policies remain in place to meet the threefold increase in electricity demand by 2050[6]	Supply-side policies targeting nuclear and offshore wind deployments, with an added 60% emissions reduction target.	More ambitious OSW targets and a higher carbon emissions reduction of 80%.
Demand	PEP annual energy and peak demand forecast (same across all scenarios). Distributed energy resources and demand-side policies not modelled.		

[5] It may also be recognized that effective DSM and load management strategies can contribute to reducing transmission congestion and may potentially defer or optimize transmission and/or generation investments.

[6] Exception is the change to the current 'priority dispatch' arrangements aimed at minimising curtailment for certain generator types.

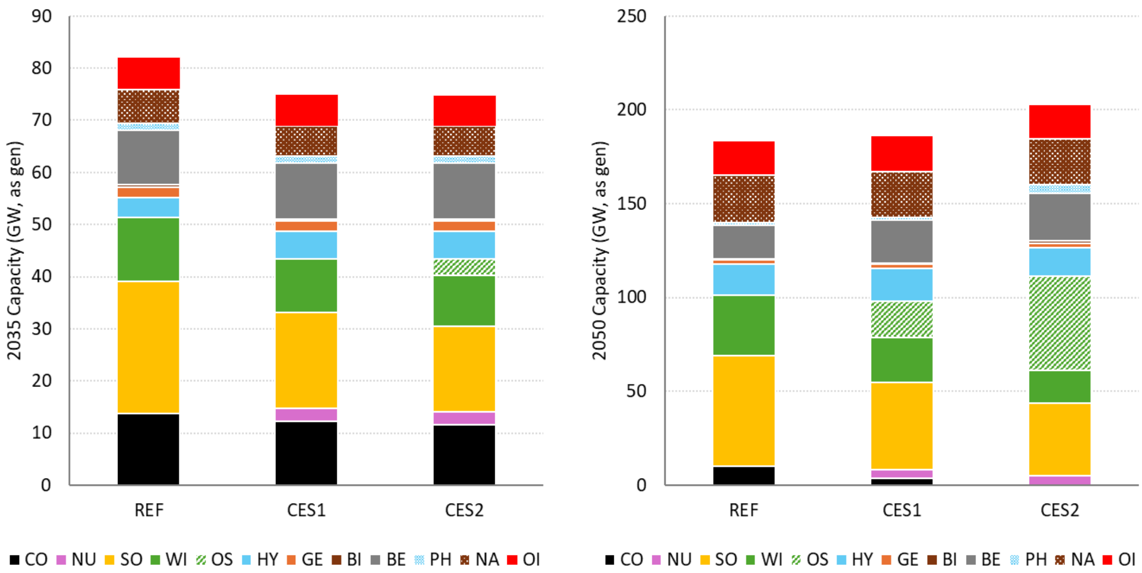
Scenario	REF	CES 1	CES 2
Technology Development	Deployment of clean energy technologies remains consistent with the current policies.	REF case with minimum addition of 19 GW offshore wind and nuclear capacity of 1200 MW by 2032, 2400 MW by 2035, and 4800 MW by 2050.	
Policy Frameworks	Existing Policies (primarily towards meeting renewable energy targets).	REF case with emissions reduction policies and coal retirement framework to facilitate orderly retirements (as required). Small-scale generation and demand-side policies not modelled.	
Infrastructure and Grid Modernisation	Transmission network and CREZ transmission investment and to accommodate higher levels of utility-scale renewable energy.		
Emission Reduction Targets	None, other than what is implied through renewable energy targets.	60% reduction in emissions against the Reference Case by 2050.	80% emissions reduction against the Reference Case by 2050.
Curtailment	Allow for up to 15% curtailment across all solar, onshore and offshore wind projects.[7]		

2.3 Capacity Requirements

The Clean Energy Scenarios are presented for comparison against the Reference Case. The primary modelling differences in these scenarios are the inclusion of 4.8 GW of nuclear capacity by 2050 and the implementation of explicit offshore wind policy targets, set at 19 GW and 50 GW by 2050 for CES1 and CES2, respectively. As shown in Figure 10, the inclusion of nuclear and the substantial build-out of offshore wind under CES1 and CES2 displace much of the solar and onshore wind capacity that would otherwise be developed under the Reference Case. The solar PV and onshore wind development trajectories, diverge from the Reference Case around 2032 with the commissioning of the first nuclear units, and from 2036 and 2041 respectively as offshore wind capacity expands.

[7] Assumes priority dispatch is retained for all other eligible generation types but allows for higher levels of curtailment for future developments. Refer to the D4 'Report on BAU and Clean Energy Scenarios' for a more detailed discussion.

Figure 10 Capacity Development Comparison



2.4 Key Assumptions

The assumptions underpinning the Reference Case and Clean Energy Scenarios are detailed in a precursory report on BAU and Clean Energy Scenarios, which discusses the assumptions used in the analysis. Key assumptions relevant to the investment plan include the following:

- **Capital expenditure or build costs for generation and transmission assets**: Figure 11 presents the capital cost assumptions for key generation technologies modelled in PLEXOS. Offshore wind and nuclear technologies exhibit significantly higher capital costs (per MW) compared to solar and onshore wind. Appendix B assesses the reasonableness of the offshore wind capex trajectory.
- **Competitive Renewable Energy Zones (CREZ) resource potential and generation profiles**: The Department of Energy, with support from USAID and NREL, has undertaken work to identify locations across the country with strong renewable energy potential. The study identified geographic areas with high concentrations of quality renewable energy resources, which have been designated as 25 CREZ, as illustrated in Figure 12. Each CREZ has a distinct profile, including renewable energy potential by generation type, resource quality and variability, and the associated costs of connecting prospective projects to the grid. The modelling prioritises these factors, while also recognising the benefits of diversifying resources across multiple locations to better manage the variable and intermittent nature of renewable generation.
- **Policy targets**: Several key supply-side policy settings drive the overall development direction across the modelled scenarios. First, renewable energy expansion is guided by the National Renewable Energy Program, which sets generation targets consistent with achieving a 35% share of renewable generation by 2030 and 50% by 2040. For the purposes of this modelling exercise, the share is assumed to increase further to 60% by 2050. In addition, the government has established nuclear development targets of 1,200 MW by 2032, 2,400 MW by 2035, and 4,800 MW by 2050. Offshore wind is also a major contributor in the Clean Energy Scenarios, with capacity targets of 19 GW under CES1 and 50 GW under CES2.

- **Fuel costs**: Fuel cost assumptions play a key role in how PLEXOS determines the least-cost generation expansion pathway, as they directly influence the variable operating costs of modelled generators. The base fuel price assumptions were taken from the Reference Scenario of the 2025 Annual Energy Outlook published by the U.S. Energy Information Administration.
- **Demand growth**: Total electricity demand, based on PEP projections, is forecast to rise from approximately 123 TWh in 2026 to around 420 TWh by 2050. This represents an increase of about 340%, equivalent to an average annual growth rate of 5.2%, and has the impact of having to develop significant new entrant capacity over the horizon.

Figure 11 Generator Capital Cost Projection (USD/kW)

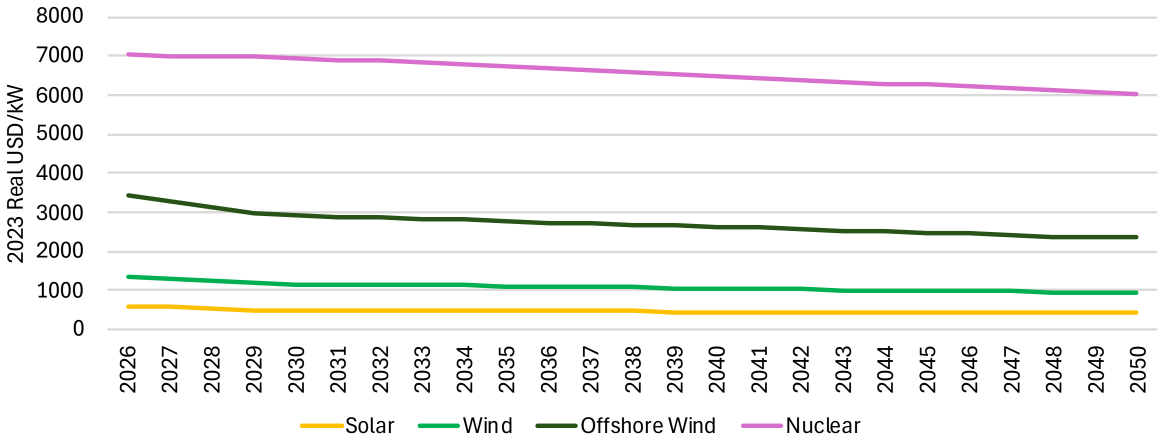
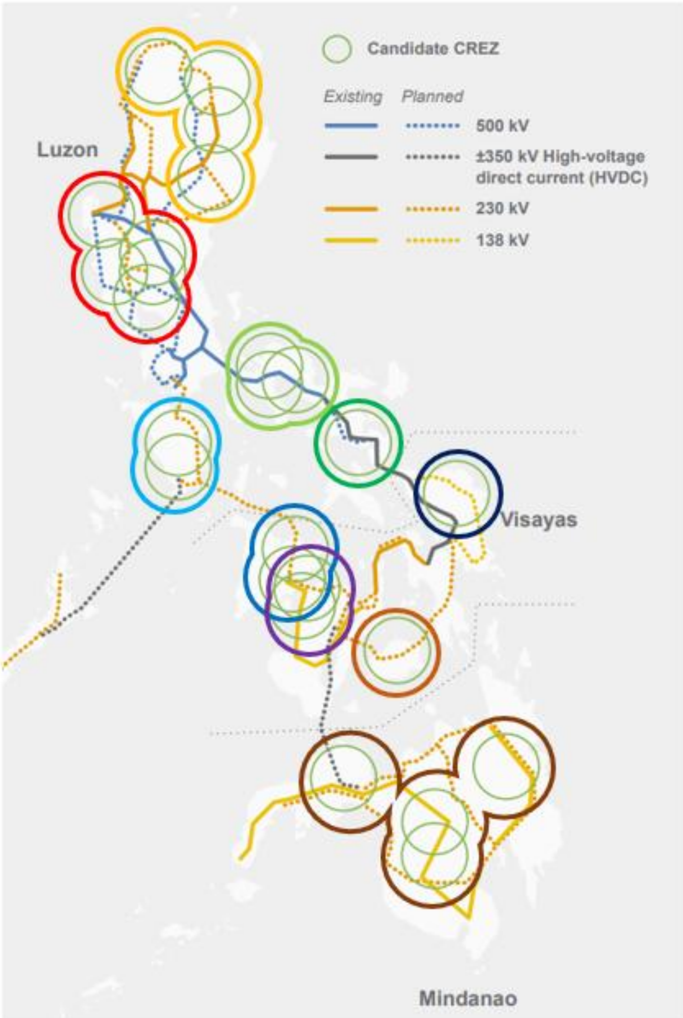


Figure 12 CREZ Locations and Aggregation



3 Generation Investment Plan

3.1 Generation Investment Plan

The Philippines' energy transition, similar to other countries, relies on the significant deployment of renewable energy capacity. Consequently, the cost structure of the power system will shift towards higher sunk costs in capital expenditure and fixed operation and maintenance costs, rather than the variable costs typically associated with traditional thermal generation such as coal. Therefore, total investment requirements are particularly important, as are the large upfront sunk costs involved.

The Figure 13 to Figure 15 plot presents the generation investment requirements across each scenario by generation type, highlighting several clear differences:

- The total generation investment in CES2 ($52 billion) is almost double that in the REF ($28 billion) over the first 10 years. By 2050, CES2 reaches more than double the REF ($296 billion compared to $134 billion).
- The divergence by 2035 is primarily driven by the first nuclear units, which account for $31 billion in CES1/2 by 2050.
- The main difference between the Reference Case and the Clean Energy Scenarios is attributed to offshore wind (approximately $2.5 million per MW, or $129 billion) and nuclear ($7 million per MW, or $31 billion).
- CES1 sits roughly midway between the REF and CES2, at $219 billion by 2050.

Figure 13 REF Generation Investment

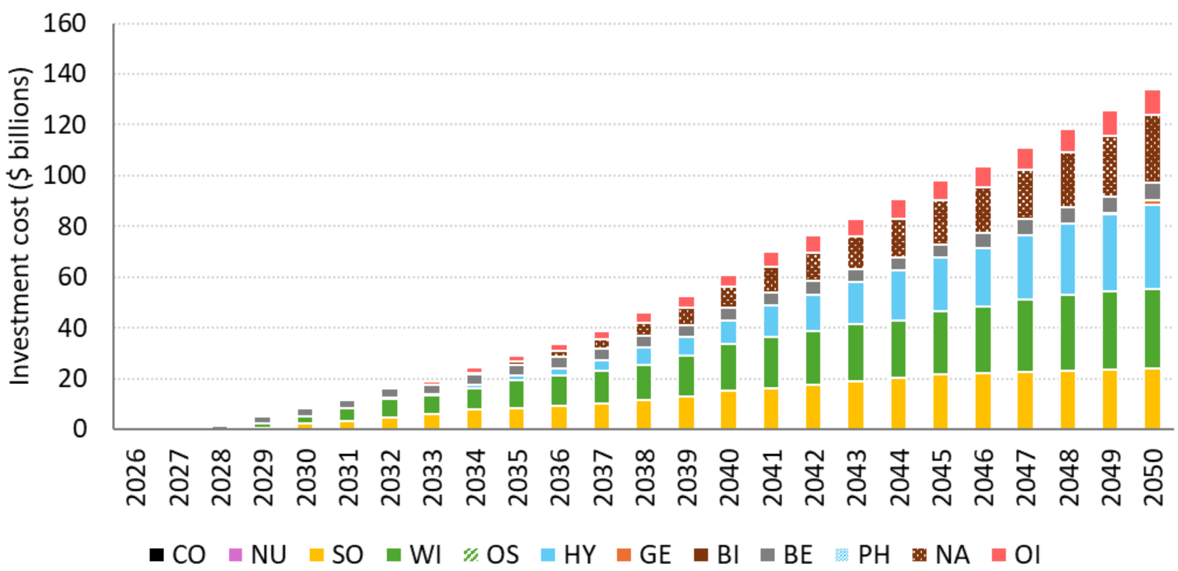


Figure 14 CES1 Generation Investment

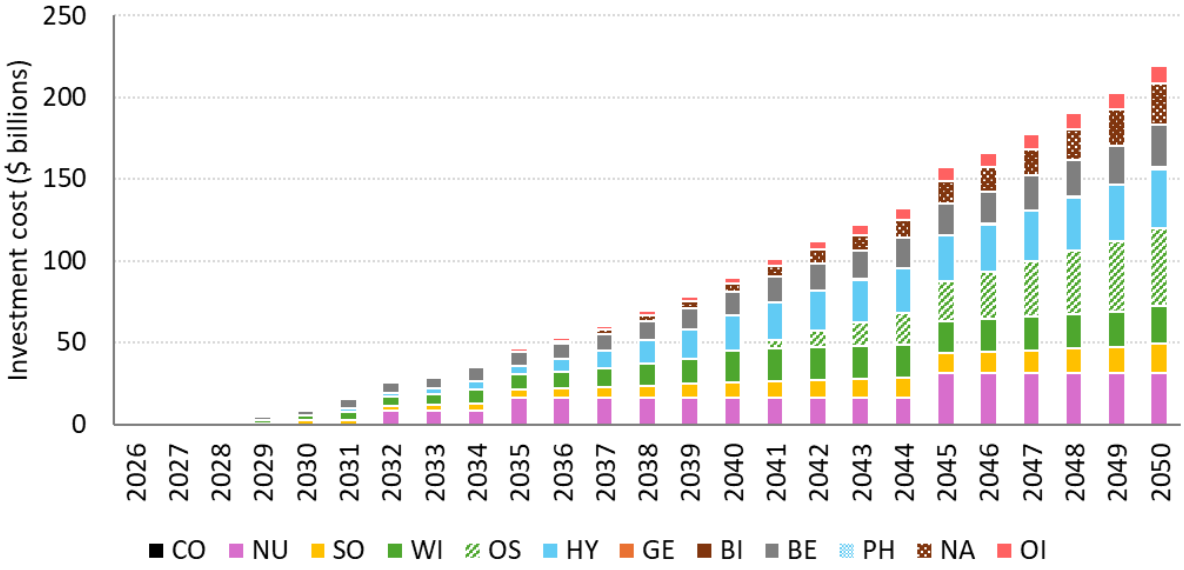


Figure 15 CES2 Generation Investment

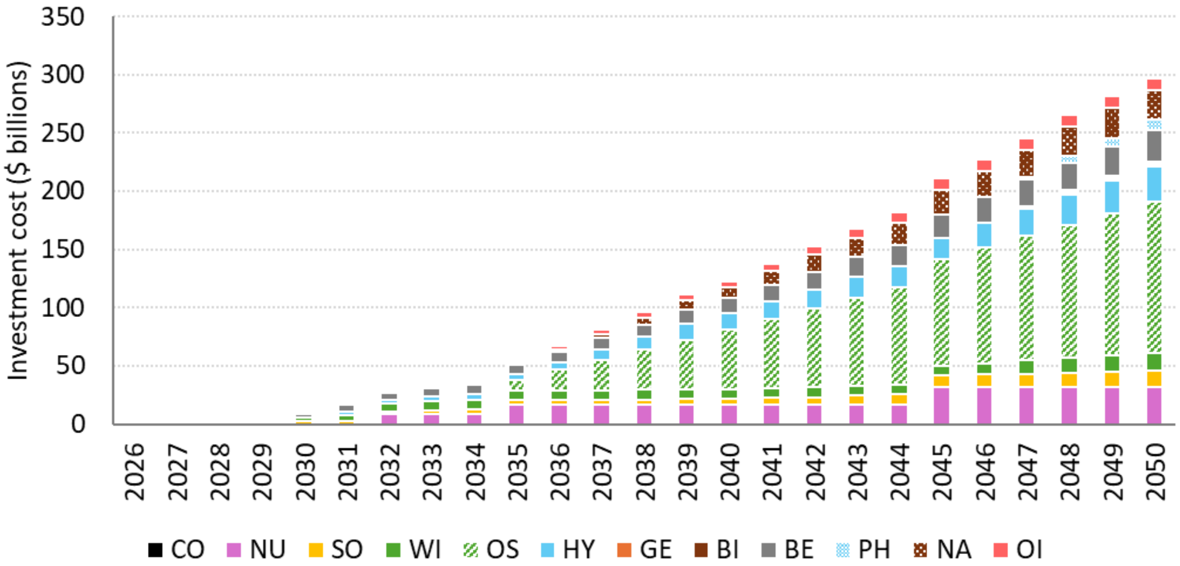
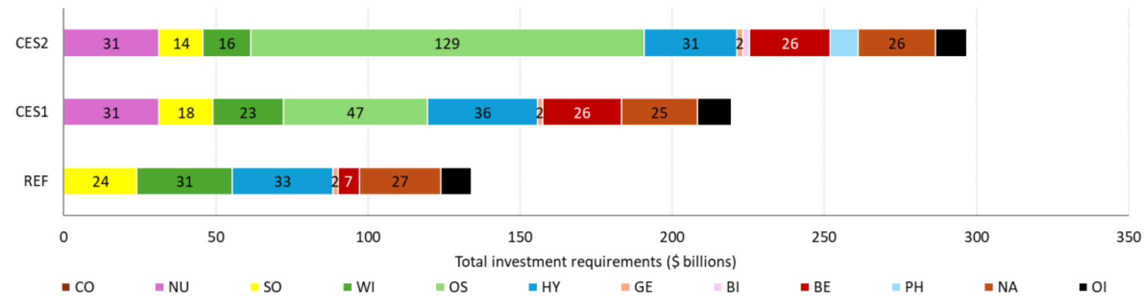


Figure 16 Generation Investment Comparison



The 5-yearly investment requirements are summarised in Figure 17. As noted earlier, the divergence in investment needs begins as early as the 2031–2035 period due to the inclusion of nuclear units, and this divergence continues through to 2050. While the Reference Case shows a moderate increase over the 2050 horizon, the required investments are significantly higher than historical levels observed in the WESM.

This is primarily due to two factors:

- The scenarios assume substantial demand growth, resulting in more than a threefold expansion of the power system over the period.
- The renewable energy transition is more capital-intensive than the traditional generation mix, particularly with the inclusion of offshore wind and nuclear.

On average, the Reference Case requires around $6 billion in generation investment per year from 2030 to 2050, compared to $11 billion and $14 billion per year for CES1 and CES2, respectively. The 2050 breakdown by broader generation grouping is outlined in Table 4.

Figure 17 Generation Investment Comparison (5-year Snapshots)

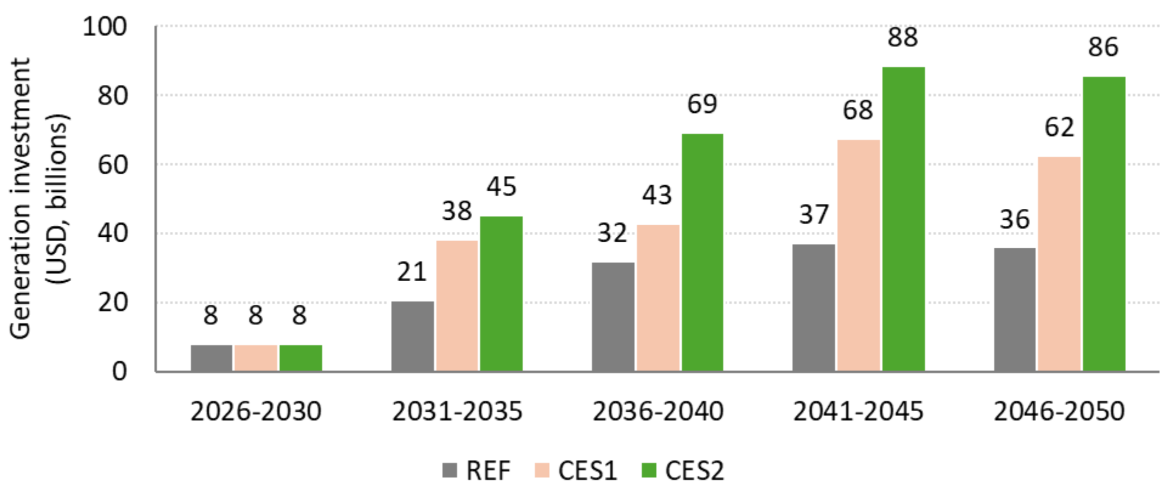


Table 4 Generation Investment by Type (2050, $ billions)

Generators	REF	CES1	CES2
Solar and onshore wind	55	41	30
Nuclear	0	31	31
Offshore wind	0	47	129
Gas, oil	37	36	36
Storage	7	26	36
Hydro, Geo, Biomass	35	38	35
Total	134	219	297

A detailed breakdown by scenario, period, and region is provided in Appendix A. However, several key investment periods are identified under the least-cost modelling, summarised in Table 5.

Table 5 Generation Investment Periods

Case	Investment Timings
Common	- Approximately $6 billion in investment is required across solar, wind, and battery projects by 2030 to meet the 2040 target of a 50% renewable generation share, as well as to address near-term reserve shortfalls through battery deployment. - Approximately $7 (CES2) to $11 billion towards hydro capacity from 2036-2050 in Luzon, and on average $19 billion towards hydro capacity in Mindanao. This is to support and firm the growing variable renewable energy generation. - Up to $5 billion required for investments in gas capacity per 5-year period to provide intermediate and peaking generation situated mainly in Luzon and Visayas.
Reference Case	- 2031–2050: Sustained investment is required in solar and onshore wind capacity, averaging around $4 billion and $5 billion per 5-year period, respectively, primarily in the Luzon CREZ locations. These CREZ areas need to be unlocked as early as 2030/2031. - In the Visayas, investments are mainly directed towards wind resources within its CREZ, at approximately $2 billion per 5-year period from 2031. - Additional investments in gas capacity are projected in Luzon from 2036 ($5.6 billion per 5-year period) and in the Visayas from 2041 ($3.8 billion per 5-year period).
CES1	- Approximately $15.5 billion is required for each 2,400 MW of nuclear capacity coming online during the 2031–2035 and 2041–2045 periods. - 2031–2050: Sustained investment is needed in solar and onshore wind capacity, averaging around $3 billion and $3.8 billion per 5-year period, respectively, primarily in the Luzon CREZ locations. Similar to the Reference Case, these CREZ areas must be unlocked as early as 2030/2031.

Case	Investment Timings
	- Around $50 billion in investment is required for offshore wind development (19 GW) over the 2041–2050 period, focused on CREZ areas off the west coast of Luzon.
CES2	- Solar and onshore wind investment requirements in Luzon are lower, at approximately $2 billion and $2.6 billion respectively, compared to the Reference Case and CES1 scenarios. - Approximately $15.5 billion is required for each 2,400 MW of nuclear capacity coming online during the 2031–2035 and 2041–2045 periods. - Approximately $35 billion is required in Luzon for offshore wind in each 5-year period from 2036 onwards. An additional $10 billion is needed for offshore wind in the Visayas (Panay) over the 2036–2045 period. - Around $6 billion per 5-year period from 2031 is needed for battery energy storage systems across the system, with 80% allocated to batteries in the Luzon CREZ. - There is also a requirement for longer-duration pumped hydro in Luzon, estimated at nearly $9 billion.

3.2 Early Coal Retirement Plan

Coal capacity outcomes across the scenarios are shown in Figure 18. Under the Reference Case, there are no early coal retirements, and the decline from 14 GW to 10 GW reflects units reaching the end of their technical life. As renewable generation increases beyond the Reference Case, higher levels of renewables progressively displace coal generation. Coal plants are then retired based on age resulting in significant early coal retirements, particularly under CES2, which requires the full retirement or phaseout of the coal fleet by 2045, compared to the phasedown to 4 GW capacity under CES1.[8] Notably, the first retirements are projected to occur as early as 2032, coinciding with the commissioning of the first nuclear unit.

The total coal retirements in each five-year period for CES1 and CES2 are provided in Table 6 and Table 7 respectively, showing that most retirements occur in the Luzon and Visayas regions.

[8] Scheduling of coal retirements was based on plant age due to limited plant data and project scope. Coal retirement basis should be based on age, and locational energy and grid strength requirements from further grid analysis.

Figure 18 Coal Capacity Comparison (System)

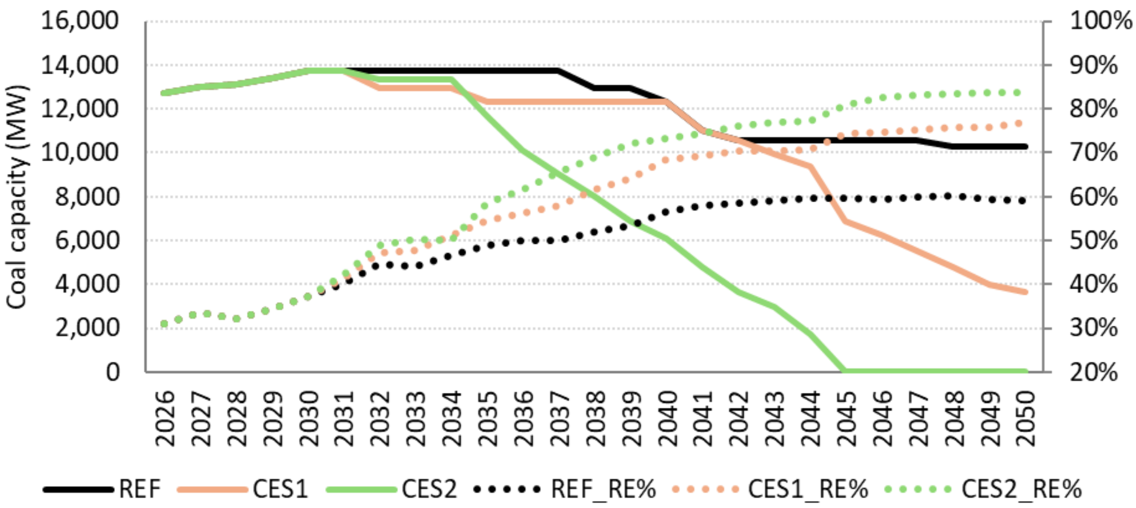


Table 6 Coal Capacity Retirement Timing by Region (CES1, MW)

MW	SYSTEM	LUZON	VISAYAS	MINDANAO
2026-2030	0	0	0	0
2031-2035	1,062	1,062	0	0
2036-2040	963	963	0	0
2041-2045	3,548	1,637	779	1,132
2046-2050	1,931	1,123	251	556

Table 7 Coal Capacity Retirement Timing by Region (CES2, MW)

MW	SYSTEM	LUZON	VISAYAS	MINDANAO
2026-2030	0	0	0	0
2031-2035	2,682	2,386	123	173
2036-2040	3,978	1,811	782	1,385
2041-2045	3,554	2,995	226	332
2046-2050	0	0	0	0

Early coal retirements, driven by continued renewable displacement, result in stranded assets, with the associated early retirement costs effectively borne by coal plant operators. Table 8 shows the number of plants retired earlier than their technical life across the scenarios. In CES2, all 66 units are retired early. Table 9 and Table 10 summarise the average number of years retirement is brought forward for these units, and the corresponding average age at retirement. Under CES2, the average retirement age is 22 years, or 18 years earlier which is substantially lower than the expected 40-year technical life of coal plants in the Philippines. Under CES1 the average retirement is brought forward 11 years.

Table 8 Early Coal Retirements (Count)

FROM	TO	REF	CES1	CES2
2031	2035	0	5	13
2036	2040	0	0	36
2041	2045	0	33	17
2046	2050	0	13	0
Total		0	51	66

Table 9 Early Coal Retirements (Years Brought Forward)

FROM	TO	REF	CES1	CES2
2031	2035	0	6	8
2036	2040	0	0	19
2041	2045	0	11	22
2046	2050	0	13	0
Average		0	11	18

Table 10 Average Age at Early Retirement

FROM	TO	REF	CES1	CES2
2031	2035		34	32
2036	2040			21
2041	2045		29	18
2046	2050		27	
Average			29	22

3.3 Carbon Emissions and Cost

Total carbon emissions under CES2 decrease by approximately 75% relative to the Reference Case by 2050, while CES1 achieves a reduction of around 53% (Figure 19). Emission levels between the scenarios begin to diverge from 2032, coinciding with the commissioning of the first nuclear units and the commencement of offshore wind developments in CES2 from 2036. The rate of emissions reduction slows in the final five years across the clean energy scenarios, while in the Reference Case, emissions rise relative to 2026 levels due to the tripling of demand by 2050.

On a grid intensity basis (Figure 20), the results show a rapid reduction across all scenarios, reflecting the increasing share of low-emission generation technologies. The decline is most pronounced in CES2, followed by CES1, consistent with the higher levels of nuclear and offshore wind development relative to the Reference Case.

Figure 19 Total System Emissions Comparison

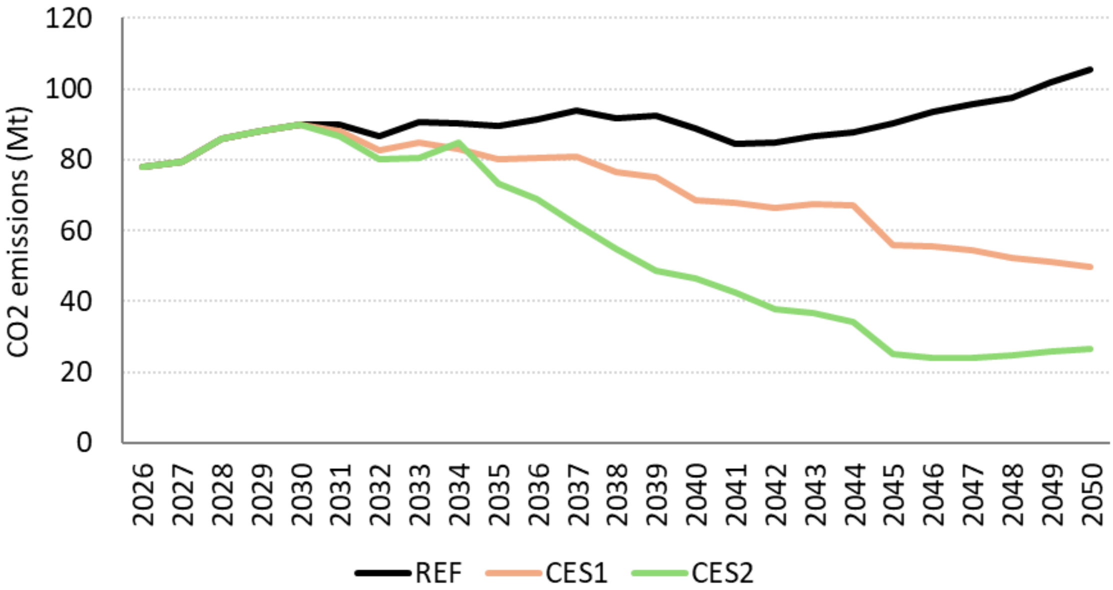
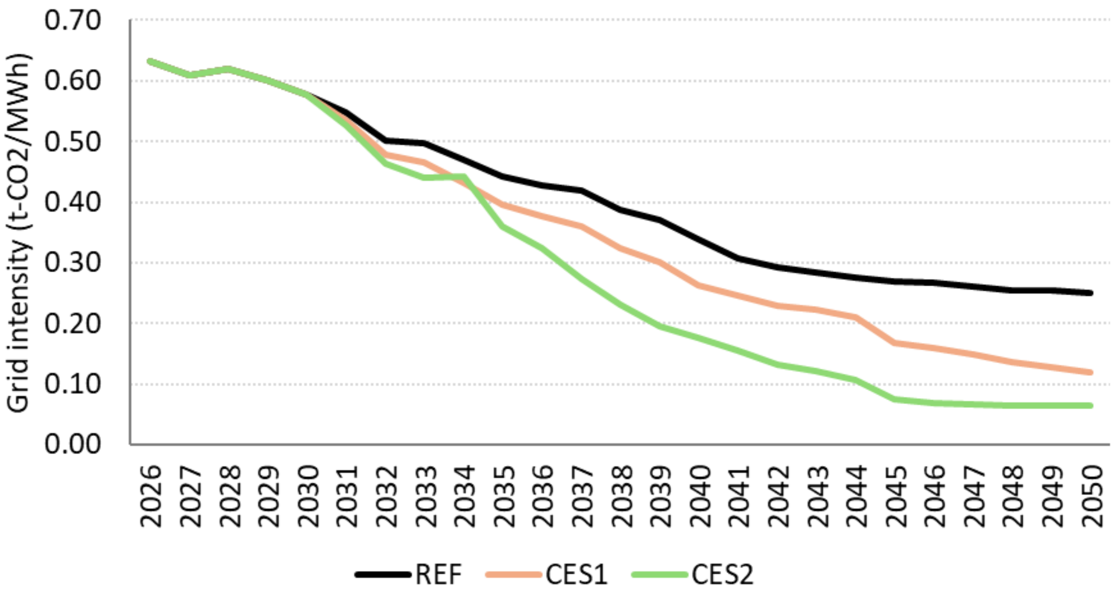


Figure 20 Grid Emissions Intensity Comparison

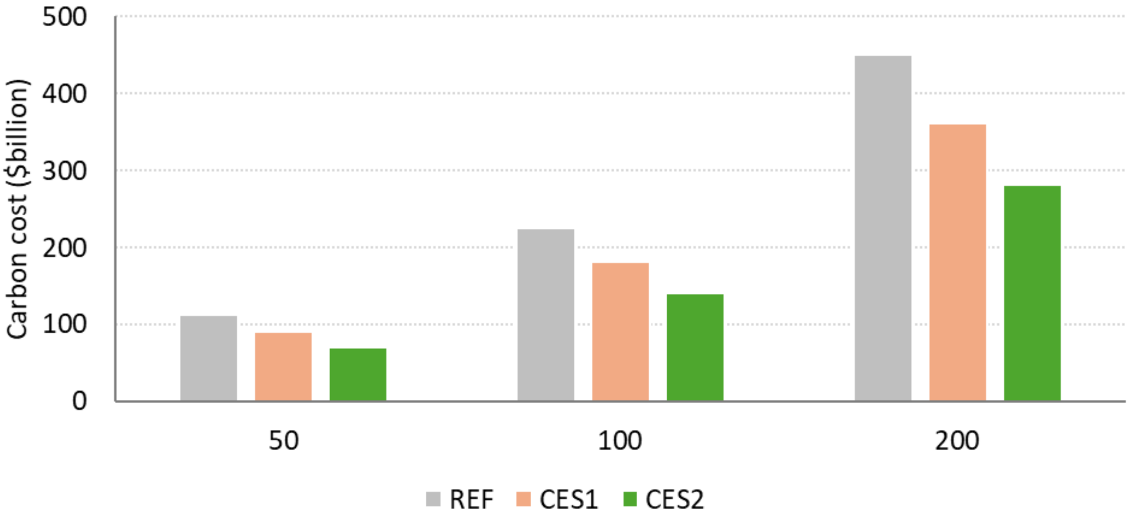


Section 3.1 shows a significant increase in investment costs associated with the more sustainable Clean Energy Scenarios (CES), as well as costs associated with early coal retirements. The benefits of the CES are evident in the much lower emissions compared to the reference scenario. Figure 21 illustrates the potential benefit of the CES by applying a range of carbon price sensitivities of $50, $100, and $200 per tonne of CO_2.[9] At $200/t-$CO_2$, CES2 generates a carbon cost of $170 billion

[9] The values are indicative and serve to illustrate the potential cost range. It may be helpful for DOE to establish an appropriate carbon price or emissions-reduction metric to support assessment of relative emissions cost differences across scenarios.

(undiscounted), which roughly offsets the generation cost difference between the REF and CES2 scenarios.

Figure 21 Total Carbon Cost (2026-2050)



4 Transmission Investment Plan

4.1 Background

The transmission investment sample plan serves as a roadmap for transmission development, based on the iterative co-optimization of generation and transmission using PLEXOS and PSS/E, as part of the ACES capacity development and mentoring activities. It focuses on long-term projects, translating them into implementable actions within a 5- to 10-year horizon, and allocates expenditures across expected lead times or implementation periods to guide scheduling and prioritization.

4.2 Transmission Investment Planning Concept

4.2.1 Horizon Transmission Investment Plan

A long-term investment transmission plan, co-optimized with generation and transmission planning, will provide a more strategic direction and financial sustainability. This approach enables the end-state transmission investment to closely align with national energy goals and generation scenario development strategies, facilitating the effective implementation of grid modernization initiatives. It also serves as a structured guide for allocating resources efficiently while managing risks and uncertainties associated with load growth and evolving policies related to climate change.

Long-term transmission planning outlines the investment in major transmission projects that serve as the transmission backbone, which are clearly identified and will account for most of the investment. These are also the transmission reinforcements that can support the most reasonable clean energy scenarios.

4.2.2 Medium-Term Transmission Investment Plan

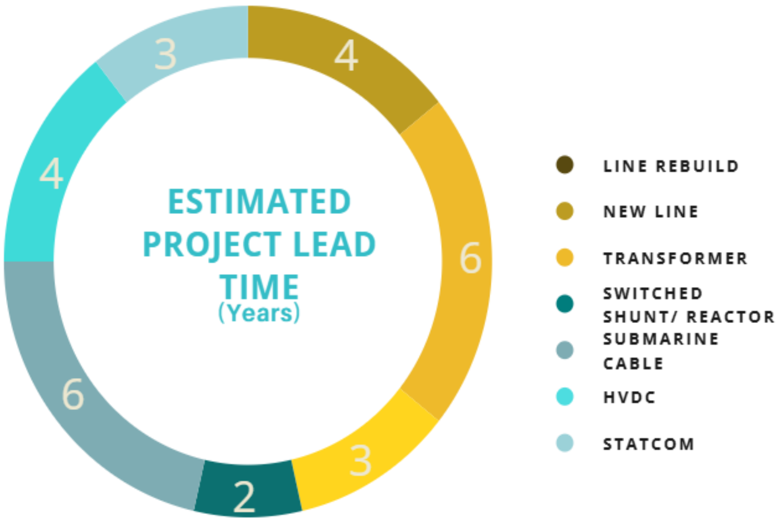
Once the long-term transmission reinforcements are identified, these can be staged into actionable projects within a 5 to 10-year horizon. This process, referred to as medium-term planning, translates long-term priorities into implementable investments. Co-optimization at the medium-term level focuses on refining project schedules and coordinating commissioning timelines with generation entry to ensure that transmission upgrades are in place when new renewable generation comes online.

4.2.3 Transmission Project Implementation Timeline

For a long-term grid roadmap, it is essential to consider both the implementation timeline and expenditure profile of new transmission projects. The lead time refers to the entire period from project approval to commissioning.

Typically, transmission lines and submarine cables require about 4 to 8 years from planning to commissioning, with an additional 3 to 4 years often needed for site selection, right-of-way acquisition, community consultations, and permitting. For instance, if a 230 kV submarine cable is required by 2035, the decision to begin construction should be made by 2028 to allow sufficient time for design, procurement, and delivery of the cables from overseas, which may add 1 to 2 years to the schedule. These timelines should be refined as each project advances beyond the feasibility stage and into detailed development. The study assumed lead times shown in Figure 22.

Figure 22 Project Lead Time per Project Type



4.2.4 Methodology

A conceptual procedure for preparing the transmission investment plan is developed within the framework of an iterative co-optimization of generation and transmission planning. The process is described below and illustrated in Figure 23.

1. The input to this procedure is a developed horizon year transmission plan specific to the current iteration of the generation-transmission co-optimization. The horizon year plan for each scenario ensures that generation siting and grid expansion are properly aligned to support the economic dispatch patterns, developed through PLEXOS in the generation planning phase, via a reliable and resilient electric grid.

2. Determine major transmission projects that support the economic dispatch for each of the clean energy scenarios and classify each as either "Robust," forming the transmission backbone, or "Flexible," needed for specific generation scenarios. As much as possible, each project should support all, if not most, of the Attributes[10] defined at the start of the transmission planning process. Conduct a reliability cost assessment where conflicts among Attributes are encountered.

    a. A reliability cost assessment determines the cost impact of reducing the reliability-related Attribute of a transmission project in favor of meeting the requirements of another Attribute. For example, additional transmissions facilities may be needed to support substantial generation development in Region A. However, the transmission solution that completely resolves Region A's need may be extremely expensive, and may therefore conflict with the minimum-cost Attribute. An alternative solution that provides a reasonable compromise between the reliability and cost Attributes needs to be identified.

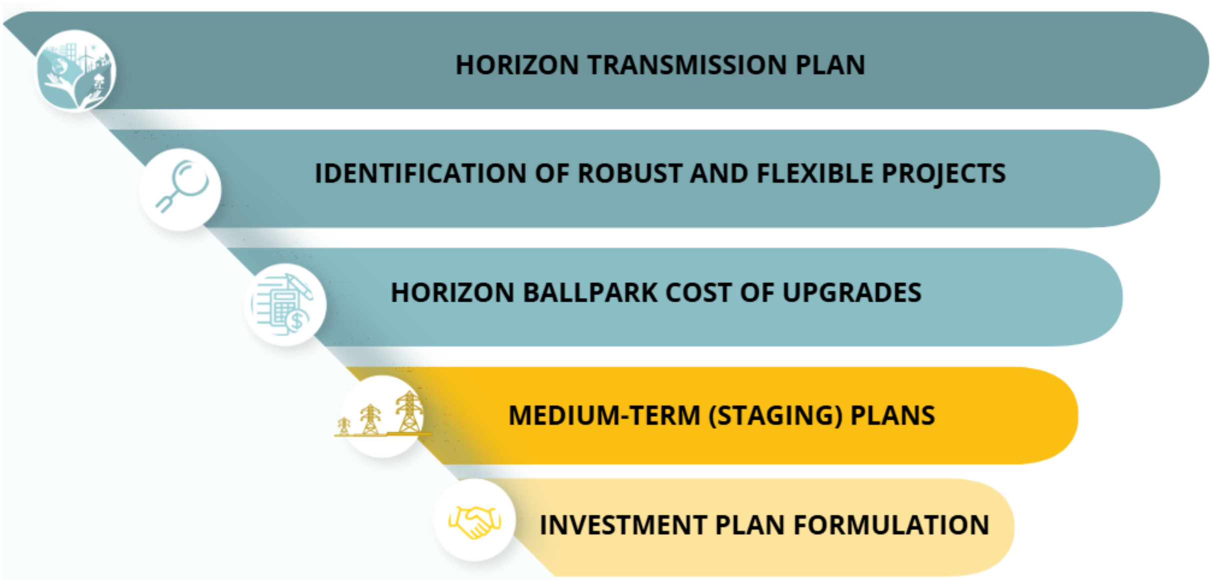
[10] Attributes serve as a guide for transmission development, starting with reliability as the top priority followed by cost efficiency. Reliability ensures that the grid meets the PGC 2016 criteria while cost efficiency emphasizes least-cost reinforcements.

b. Reliability cost assessment compares the value of the various solutions to the transmission need in terms of the reliability cost components comprising the investment and operating costs and the cost of unreliability. The cost of unreliability can derive from curtailments due to congestion, such as unserved load or economic generation that needs to be re-dispatched.

c. The alternative that offers the least reliability cost is the chosen solution.

3. Develop the cost estimates for each project, whether robust or flexible, to support investment planning and financial analysis.
4. Create medium-term models to stage long-term projects into actionable investments within a 5 to 10-year period. Align these models with expected generation entry schedules to ensure timely transmission availability for new capacity additions.
5. Evaluate when each horizon-year project needs to be staged to support the medium-term generation and load forecast using the same reliability assessments applied in horizon-year studies.
6. Account for typical construction and procurement lead times to ensure projects are completed before they are needed, as shown in Figure 22.
7. Reassess and update investment priorities for each staging period to reflect changes in generation entry, demand growth, and policy direction.
8. Establish a final list of medium-term transmission projects and allocate their estimated costs across their implementation lead times to guide the funding and expenditure schedule.

Figure 23 Investment Planning Conceptual Procedure



4.2.5 ACES Transmission Investment Plan

This section presents the transmission upgrades identified from each generation scenario's 2050 economic dispatch results. To illustrate the process, a simple reinforcement method was used by adding parallel facilities to overloaded equipment until the loading was resolved.

Analysing the MW and MVar flows on each monitored facility, formulate a preliminary view of the required upgrade, such as adding a new line, rebuilding an existing one, or combining both, to determine the transmission upgrade cost.

This approach provides a holistic view of the grid, allowing transmission planners to see where reinforcements are most needed to effectively deliver generation to the load. It also provides a quick estimation of transmission costs, which can be fed back into generation planning, helping to refine the identification of transmission reinforcements as the co-optimization process continues.

4.2.6 Clean Energy Scenario Transmission Projects

The list of transmission projects presented in this subsection is derived from the steady-state assessment discussed in the BAU and Clean Energy Scenarios modelling step.[11] Each project is classified as either robust or flexible to accommodate the simulated clean energy economic dispatch scenarios. These projects were then assessed for staging to support the medium-term generation and load forecasts, considering typical construction and procurement lead times.

Note that most of the identified transmission projects for each grid are based on the existing TDP 2024/25. The identified plan incorporates modifications to selected projects and introduces additional upgrades where needed, while maintaining the overall framework and direction of the current transmission development plan.

The type of transmission upgrades is categorized as follows:

- Rebuild: Rebuilding a transmission line involves replacing most significant components of an existing circuit, such as structures, conductors and hardware, while maintaining the existing right-of-way. This type of project will increase the line thermal ratings to improve reliability performance.
- New Lines: Constructing a new circuit in parallel with an existing line provides additional thermal capacity and reduces loading on the original circuit. Parallel lines also improve contingency performance. These may be overhead lines or submarine cables.
- HVDC: New HVDC lines provide more bulk power transfer capability between grids.
- New Transformers: This project adds new power transformers within an existing substation footprint where high-side/low-side terminations can be accommodated. Adding transformers increases capacity at the substation and reduces the loading of existing transformers during normal and contingency conditions.
- Replace Transformers: This involves removing existing transformers and installing higher-capacity replacements at the same substation.

[11] Refer to the precursory BAU and Clean Energy Scenarios report for further details.

- Reactive Support: This involves installing shunt capacitors, shunt reactors, or similar technologies to maintain acceptable voltage levels and reactive margins under normal and contingency conditions.

4.2.6.1 Luzon Transmission Projects

Immediate transmission expansion is needed along the 230 kV Laoag–Bauang corridor in Northern Luzon and in Central Luzon, particularly in the Bataan area. These upgrades involve rebuilding or modifying existing facilities to increase their MVA capacity. Substation expansions, including the addition of transformers at delivery points in Metro Manila, Laguna, and the Bicol region, are required by 2035.

By 2040, rebuilding of the 500 kV Dasmariñas–Silang line and the 230 kV southern transmission corridor (Malamig–Biñan–Silang–Dasmariñas and Taguig–Taytay paths) serving Metro Manila will be necessary. Additional submarine cables between Limay Cable Termination Station (CTS) and Pasay CTS are also expected by 2040. Beyond 2040, power exchange between the Luzon and Visayas grids is projected to rise significantly, requiring a series of HVDC links to support interregional transfer capability.

These robust transmission reinforcements are listed in Table 11 along with their corresponding target in-service years.

Table 11 Robust Transmission Projects - Luzon

Target In-Service Year	Project Type	Description	kV	District
2035	Rebuild	BCCPPA - BCCPPB 230	230	Central Luzon
2035	Rebuild	BCCPPA - LIMAY 230	230	Central Luzon
2035	Rebuild	PANTABANGAN - SAMPALOC 230	230	Central Luzon
2035	Rebuild	NEW HERMOSA - OLONGAPO 230	230	Central Luzon
2035	Rebuild	OLONGAPO - SBMA 230	230	Central Luzon
2035	New Transformers	NAGSAAG 230/69	230/69	Central Luzon
2035	New Transformers	GUAGUA 230/69	230/69	Central Luzon
2035	New Transformers	LIMAY 230/69	230/69	Central Luzon
2035	New Transformers	PORAC 230/69	230/69	Central Luzon
2035	New Transformers	CABANATUAN 230/69	230/69	Central Luzon
2035	New Transformers	CONCEPCION 230/69	230/69	Central Luzon
2035	New Transformers	CLARK 230/69	230/69	Central Luzon
2035	New Transformers	SAN SIMON 230/69	230/69	Central Luzon
2035	New Transformers	APALIT 230/69	230/69	Central Luzon
2035	New Transformers	CAPAS 230/69	230/69	Central Luzon
2035	New Transformers	SN AGUSTIN 230/69	230/69	Central Luzon
2035	New Transformers	MALOLOS 230/69	230/69	Central Luzon
2035	New Transformers	PLARIDEL 230/69	230/69	Central Luzon
2035	New Transformers	LABRADOR 230/69	230/69	Central Luzon
2035	New Transformers	SBMA 230/69	230/69	Central Luzon
2035	New Transformers	SAN RAFAEL 230/69	230/69	Central Luzon
2035	New Transformers	BACOLOR 230/69	230/69	Central Luzon
2035	Rebuild	LAOAG - PINILI 230	230	Northern Luzon
2035	Rebuild	SAN ESTEBAN - NEW BANTAY 230	230	Northern Luzon
2035	Rebuild	BAUANG - BALAOAN 230	230	Northern Luzon
2035	Rebuild	PINILI - NEW BANTAY 230	230	Northern Luzon

Target In-Service Year	Project Type	Description	kV	District
2035	New Transformers	SAN ESTEBAN 230/115	230/115	Northern Luzon
2035	New Transformers	NEW BANTAY 230/69	230/69	Northern Luzon
2035	New Transformers	BINGA 230/69	230/69	Northern Luzon
2035	New Transformers	TUGUEGARAO 230/69	230/69	Northern Luzon
2035	New Transformers	BAYOMBONG 230/69	230/69	Northern Luzon
2035	New Transformers	BAUANG 230/69	230/69	Northern Luzon
2035	New Transformers	LA TRINIDAD 230/69	230/69	Northern Luzon
2035	New Transformers	SAN MATEO 230/115	230/115	Southern Luzon
2035	New Transformers	SAN JOSE 230/115	230/115	Southern Luzon
2035	New Transformers	FBGC 230/115	230/115	Southern Luzon
2035	New Transformers	NUVALI 230/115	230/115	Southern Luzon
2035	New Transformers	TANAUAN 230/69	230/69	Southern Luzon
2035	New Transformers	LUMBAN 230/69	230/69	Southern Luzon
2035	New Transformers	BAY 230/69	230/69	Southern Luzon
2035	New Transformers	IRIIGA 230/69	230/69	Southern Luzon
2035	New Transformers	LABO 230/69	230/69	Southern Luzon
2035	New Transformers	NAGA 230/69	230/69	Southern Luzon
2035	New Transformers	DARAGA 230/69	230/69	Southern Luzon
2035	New Transformers	ABUYOG 230/69	230/69	Southern Luzon
2035	New Transformers	BACNOTAN 230/69	230/69	Southern Luzon
2035	New Transformers	TAGUIG 500/230	500/230	Southern Luzon
2035	New Transformers	DASMARIÑAS 500/230	500/230	Southern Luzon
2035	New Transformers	DUHAT 500/230	500/230	Southern Luzon
2035	New Transformers	SILANG 500/230	500/230	Southern Luzon
2040	Rebuild	SAN JUAN - MASIIT 230	230	Central Luzon
2040	Rebuild	QUEZON - DOÑA IMELDA 230	230	Central Luzon
2040	New Lines	LIMAY CTS - PASAY CTS 230	230	Southern Luzon
2040	Rebuild	NAVOTAS - DOÑA IMELDA 230	230	Southern Luzon
2040	Rebuild	NAVOTAS - DUHAT 230	230	Southern Luzon
2040	Rebuild	QUEZON - SAN JOSE 230	230	Southern Luzon
2040	Rebuild	TAYTAY - TAGUIG 230	230	Southern Luzon
2040	Rebuild	TAGUIG - FBGC 230	230	Southern Luzon
2040	Rebuild	BIÑAN - MALAMIG 230	230	Southern Luzon
2040	Rebuild	BIÑAN - SILANG 230	230	Southern Luzon
2040	Rebuild	DASMARIÑAS - AMADEO 230	230	Southern Luzon
2040	Rebuild	DASMARIÑAS - SILANG 500	500	Southern Luzon
2041-2050	HVDC	LVIP HVDC Link		Southern Luzon

For the CES 1 scenario, flexible transmission upgrades are not expected to be required until around 2040, given the scale of renewable energy development under this case. In contrast, the CES 2 scenario will require flexible transmission projects as early as 2035, as it assumes a more rapid and extensive generation expansion. These flexible reinforcements, along with their target in-service years, are summarized in Table 12.

Table 12 Flexible Transmission Projects – Luzon

Generation Scenario	In-Service Year	Project Type	Description	kV	District
CES 1	2040	Rebuild	DINADIAWAN - BALER 230	230	Central Luzon
CES 1	2040	Rebuild	SUBIC - CASTILLEJOS 230	230	Central Luzon
CES 1	2040	Rebuild	BCCPPB - LAMAO 230	230	Central Luzon
CES 1	2040	New Transformers	MEXICO 230/69	230/69	Central Luzon
CES 1	2040	Rebuild	BINGA - LA TRINIDAD 230	230	Northern Luzon
CES 1	2040	New Transformers	SAN ESTEBAN 115/69	115/69	Northern Luzon
CES 1	2040	New Transformers	BACNOTAN 230/69	230/69	Northern Luzon
CES 1	2040	Rebuild	MECO - BAY 230	230	Southern Luzon
CES 1	2040	Rebuild	BAY - ALAMINOS 230	230	Southern Luzon
CES 1	2040	New Transformers	BATANGAS 230/69	230/69	Southern Luzon
CES 1	2040	New Transformers	ALAMINOS 500/230	500/230	Southern Luzon
CES 2	2035	Rebuild	GUMACA - LABO 230	230	Southern Luzon
CES 2	2035	Rebuild	TAYABAS - NAGA 230	230	Southern Luzon
CES 2	2035	Rebuild	LABO - NAGA 230	230	Southern Luzon
CES 2	2035	Rebuild	NAGA - DARAGA 230	230	Southern Luzon
CES 2	2035	Rebuild	TIWI C - DARAGA 230	230	Southern Luzon
CES 2	2035	New Transformers	NAGA 500/230	500/230	Southern Luzon
CES 2	2035	Rebuild	NEW HERMOSA - SBMA 230	230	Central Luzon
CES 2	2040	Rebuild	NEW HERMOSA - SBMA 230	230	Central Luzon
CES 2	2040	Rebuild	DINADIAWAN - BALER 230	230	Central Luzon
CES 2	2040	Rebuild	SUBIC - CASTILLEJOS 230	230	Central Luzon
CES 2	2040	Rebuild	SAMPALOC - BALER 230	230	Central Luzon
CES 2	2040	New Lines	MARIVELES CTS - MARIVELES OSW	500	Central Luzon
CES 2	2040	New Transformers	NAVOTAS 230/110	230/110	Central Luzon
CES 2	2040	New Transformers	ANTIPOLO 230/110	230/110	Central Luzon
CES 2	2040	New Transformers	VALENZUELA 230/110	230/110	Central Luzon
CES 2	2040	New Transformers	SANTIAGO 230/69	230/69	Central Luzon
CES 2	2040	New Transformers	MEXICO 230/69	230/69	Central Luzon
CES 2	2040	New Transformers	GAMU 230/69	230/69	Central Luzon
CES 2	2040	New Transformers	LIMAY 230/69	230/69	Central Luzon
CES 2	2040	New Transformers	CLARK 230/69	230/69	Central Luzon
CES 2	2040	New Transformers	NAGSAAG 500/230	500/230	Central Luzon
CES 2	2040	New Transformers	HERMOSA 500/230	500/230	Central Luzon
CES 2	2040	New Transformers	SAN ISIDRO 500/230	500/230	Central Luzon
CES 2	2040	Rebuild	LAOAG - NEW LAOAG 230	230	Northern Luzon
CES 2	2040	Rebuild	SAN ESTEBAN - BALAOAN 230	230	Northern Luzon
CES 2	2040	Rebuild	SAN ESTEBAN - SAGADA 230	230	Northern Luzon
CES 2	2040	Rebuild	BAUANG - BPPC 230	230	Northern Luzon
CES 2	2040	Rebuild	BAUANG - SANFABIAN 230	230	Northern Luzon
CES 2	2040	Rebuild	BPPC - SAN FABIAN 230	230	Northern Luzon
CES 2	2040	Rebuild	BANGUI - SANCHEZ MIRA 230	230	Northern Luzon
CES 2	2040	Rebuild	AMBUKLAO - BAYOMBONG 230	230	Northern Luzon
CES 2	2040	Rebuild	BINGA - LA TRINIDAD 230	230	Northern Luzon

Generation Scenario	In-Service Year	Project Type	Description	kV	District
CES 2	2040	Rebuild	LA TRINIDAD - SAGADA 230	230	Northern Luzon
CES 2	2040	Rebuild	BALINGUEO - SAN FABIAN 230	230	Northern Luzon
CES 2	2040	Rebuild	LABRADOR - BOLO 230	230	Northern Luzon
CES 2	2040	Rebuild	TUGUEGARAO - MAGAPIT 230	230	Northern Luzon
CES 2	2040	Rebuild	TUG UEGARAO - CABATUAN 230	230	Northern Luzon
CES 2	2040	Rebuild	GAMU - CABATUAN 230	230	Northern Luzon
CES 2	2040	Rebuild	BAYOMBONG - NEW SANTIAGO 230	230	Northern Luzon
CES 2	2040	Rebuild	SANCHEZ MIRA - PUDTOL 230	230	Northern Luzon
CES 2	2040	Rebuild	PUDTOL - GENED 230	230	Northern Luzon
CES 2	2040	Rebuild	GENED - KABUGAO 230	230	Northern Luzon
CES 2	2040	Rebuild	NEW SANTIAGO - ALIMIT 230	230	Northern Luzon
CES 2	2040	Rebuild	NEW SANTIAGO - CABATUAN	230	Northern Luzon
CES 2	2040	Rebuild	ALI MIT - DINADIAWAN 230	230	Northern Luzon
CES 2	2040	New Lines	BOLO - BALAOAN 500	500	Northern Luzon
CES 2	2040	New Lines	LAOAG - BALAOAN 500	500	Northern Luzon
CES 2	2040	New Transformers	SAN ESTEBAN 115/69	115/69	Northern Luzon
CES 2	2040	New Transformers	SAN ESTEBAN 115/69	115/69	Northern Luzon
CES 2	2040	New Transformers	KALINGA 500/230	500/230	Northern Luzon
CES 2	2040	New Transformers	KABUGAO 500/230	500/230	Northern Luzon
CES 2	2040	Rebuild	BIÑAN - NUVALI 230	230	Southern Luzon
CES 2	2040	Rebuild	LUMBAN - GUMACA 230	230	Southern Luzon
CES 2	2040	Rebuild	CALAUAN - MASIIT 230	230	Southern Luzon
CES 2	2040	Rebuild	GUMACA - LABO 230	230	Southern Luzon
CES 2	2040	Rebuild	TAYABAS - NAGA LUZON 230	230	Southern Luzon
CES 2	2040	Rebuild	LABO - NAGA LUZON 230	230	Southern Luzon
CES 2	2040	Rebuild	NAGA LUZON - DARAGA 230	230	Southern Luzon
CES 2	2040	Rebuild	TIWI C - DARAGA 230	230	Southern Luzon
CES 2	2040	Rebuild	MECO - BAY 230	230	Southern Luzon
CES 2	2040	Rebuild	BAY - ALAMINOS 230	230	Southern Luzon
CES 2	2040	Rebuild	DARAGA - TUBLIJON 230	230	Southern Luzon
CES 2	2040	Rebuild	ABUYOG - MATNOG 230	230	Southern Luzon
CES 2	2040	Rebuild	STA MARIA - TAYABAS 500	500	Southern Luzon
CES 2	2040	Rebuild	SILANG - ALAMINOS 500	500	Southern Luzon
CES 2	2040	Rebuild	PAGBILAO - TAYABAS 500	500	Southern Luzon
CES 2	2040	Rebuild	PAGBILAO - TAGKAWAYAN 500	500	Southern Luzon
CES 2	2040	Rebuild	TAGKAWAYAN - NAGA 500	500	Southern Luzon
CES 2	2040	Rebuild	PINAMUKAN - ALAMINOS 500	500	Southern Luzon
CES 2	2040	Rebuild	PINAMUKAN - PINAMUKAN CTS 500	500	Southern Luzon

Generation Scenario	In-Service Year	Project Type	Description	kV	District
CES 2	2040	Rebuild	PINAMUKAN CTS - LOBO CTS 500	500	Southern Luzon
CES 2	2040	New Lines	LOBO - MAHAL NA PANGALAN 500	500	Southern Luzon
CES 2	2040	New Transformers	MUNTNLPA 230/110	230/110	Southern Luzon
CES 2	2040	New Transformers	BATANGAS 230/69	230/69	Southern Luzon
CES 2	2040	New Transformers	MEXICO 230/69	230/69	Southern Luzon
CES 2	2040	New Transformers	TAYABAS 500/230	500/230	Southern Luzon
CES 2	2040	New Transformers	NAGA 500/230	500/230	Southern Luzon
CES 2	2040	New Transformers	TAGKAWAYAN 500/230	500/230	Southern Luzon
CES 2	2040	New Transformers	ALAMINOS 500/230	500/230	Southern Luzon
CES 2	2040	New Transformers	LAOAG 500/230	500/230	
CES 2	2041-2050	Rebuild	TAYABAS - NAGA 230	230	Southern Luzon
CES 2	2041-2050	Rebuild	LABO - NAGA 230	230	Southern Luzon
CES 2	2041-2050	New Transformers	NAGA 500/230	500/230	Southern Luzon
REF	2035	Rebuild	HERMOSA - BALANGA 230	230	Central Luzon
REF	2035	Rebuild	BCCPPB - LAMAO 230	230	Central Luzon
REF	2035	Rebuild	BCCPPB - BALANGA 230	230	Central Luzon
REF	2035	Rebuild	LAMAO - POWER 230	230	Central Luzon
REF	2035	Rebuild	GUMACA - LABO 230	230	Southern Luzon
REF	2035	Rebuild	LABO - NAGA LUZON 230	230	Southern Luzon
REF	2035	Rebuild	TIWI C - DARAGA 230	230	Southern Luzon
REF	2040	New Transformers	MEXICO 230/69	230/69	Central Luzon
REF	2040	New Transformers	SAN ESTEBAN 115/69	115/69	Northern Luzon
REF	2040	New Transformers	LATRINIDAD 230/69	230/69	Northern Luzon
REF	2040	Rebuild	FBGC - MANILA 230	230	Southern Luzon
REF	2040	Rebuild	CALAMBA - BIÑAN 230	230	Southern Luzon
REF	2040	Rebuild	CALAMBA - MECO 230	230	Southern Luzon
REF	2040	Rebuild	MECO - BAY 230	230	Southern Luzon
REF	2040	Rebuild	BAY - ALAMINOS 230	230	Southern Luzon
REF	2040	Rebuild	STA MARIA - TAYABAS 500	500	Southern Luzon
REF	2040	Rebuild	PINAMUKAN - ILIJAN 500	500	Southern Luzon
REF	2040	Rebuild	PINAMUKAN - ALAMINOS 500	500	Southern Luzon
REF	2040	Rebuild	SILANG - ALAMINOS 500	500	Southern Luzon
REF	2040	Rebuild	PAGBILAO - TAYABAS 500	500	Southern Luzon
REF	2040	Rebuild	PAGBILAO - ATIMONAN 500	500	Southern Luzon
REF	2040	New Transformers	BATANGAS 230/69	230/69	Southern Luzon
REF	2040	New Transformers	ALAMINOS 500/230	500/230	Southern Luzon
REF	2040	New Transformers	TAYABAS 500/230	500/230	Southern Luzon
REF	2040	New Transformers	NAGA 500/230	500/230	Southern Luzon

4.2.6.2 Visayas Transmission Projects

Most of the robust transmission projects in the Visayas Grid, shown in Table 13, involve additional inter-island interconnections in Leyte, Samar, and Bohol, along with new 230/138 kV facilities linked to these corridors. Where series of parallel upgrades are required, they are staged between the medium-term and horizon years to match the growth of renewable generation and the increasing power exchange between Naga in Luzon and Leyte in the Visayas.

Table 13 Robust Transmission Projects – Visayas

Target In-service Year	Project Type	Description	kV	District
2035	Rebuild	CORELLA - MARIBOJOC CTS 230	230	BOHOL
2035	Rebuild	CORELLA - UBAY 230	230	BOHOL
2035	New Lines	MARBOJOC CTS - ARGAO CTS 230	230	BOHOL/CEBU
2035	Rebuild	LUDO - CORDOVA 230	230	CEBU
2035	Rebuild	UMAPAD - PUSOK 230	230	CEBU
2035	Rebuild	CEBU - BOBON 230	230	CEBU
2035	Rebuild	MAGDUGO - CALONGCALONG 138	138	CEBU
2035	Rebuild	CEBU - UMAPAD 230	230	CEBU
2035	Rebuild	COMPOSTELA - CEBU 138	138	CEBU
2035	Rebuild	DANAO - BOBON 230	230	CEBU
2035	Rebuild	ARGAO CTS - DUMANJUG 230	230	CEBU
2035	Rebuild	DANAO - TALISAY 230	230	CEBU
2035	New Lines	DANAO - TALISAY 230	230	CEBU
2035	Replace Transformers	COMPOSTELA 230/138	230/138	CEBU
2035	Replace Transformers	DUMANJUG 230/138	230/138	CEBU
2035	Rebuild	ORMOC - TUGAS 230	230	LEYTE
2035	New Lines	ORMOC - TUGAS 230	230	LEYTE
2035	Rebuild	ORMOC -SUMANGGA 138	138	LEYTE
2035	Rebuild	TGPP - ISABEL 138	138	LEYTE
2035	Replace Transformers	ORMOC 230/138	230/138	LEYTE
2035	Replace Transformers	ISABEL 138/69	138/69	LEYTE
2035	New Lines	GUADALUPE - TUGAS 230	138	LEYTE/BOHOL
2035	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/CEBU
2035	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2035	Rebuild	PONDOL - AMLAN 138	138	NEGROS
2035	Rebuild	BACOLOD - CADIZ 138	138	NEGROS
2035	New Lines	EB MAGALONA -BAROTAC VIEJO 230	230	NEGROS /PANAY
2035	Rebuild	ILOILO - MANDURRIAO 138	138	PANAY
2035	Rebuild	STA BARBARA - MANDURRIAO 138	138	PANAY
2035	Rebuild	DINGLE - BAROTAC VIEJO 138	138	PANAY
2035	Replace Transformers	STA BARBARA 138/69	138/69	PANAY
2035	Replace Transformers	SAN JOSE 69	138/69	PANAY
2035	Replace Transformers	CALBAYOG 138/69	138/69	SAMAR
2040	New Lines	CORELLA - MARIBOJOC CTS 230	230	BOHOL

Target In-service Year	Project Type	Description	kV	District
2040	New Lines	MARIBOJOC CTS - ARGAO CTS 230	230	BOHOL/CEBU
2040	New Lines	DANAO - BOBON 230	230	CEBU
2040	New Lines	DANAO - TALISAY 230	230	CEBU
2040	New Transformers	COMPOSTELA 230/138	230/138	CEBU
2040	New Transformers	DUMANJUG 230/138	230/138	CEBU
2040	New Transformers	QUIOT 138/69	138/69	CEBU
2040	New Transformers	CALONGCALONG 138/69	138/69	CEBU
2040	New Lines	SAMBOAN - PONDOL 138	138	CEBU/NEGROS
2040	New Lines	ORMOC - TUGAS 230	230	LEYTE
2040	New Transformers	ORMOC 230/138	230/138	LEYTE
2040	New Lines	GUADALUPE - TUGAS 230	230	LEYTE/BOHOL
2040	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/CEBU
2040	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2040	New Transformers	AMLAN 138/69	138/69	NEGROS
2040	New Lines	EB MAGALONA -BAROTAC VIEJO 230	230	NEGROS /PANAY
2040	New Transformers	MANDURRIAO 138/69	138/69	PANAY
2040	New Transformers	STA BARBARA 230/138	230/138	PANAY
2045	New Lines	MARBOJOC CTS - ARGAO CTS 230	230	BOHOL/CEBU
2045	New Lines	DANAO - BOBON 230	230	CEBU
2045	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/CEBU
2045	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2045	New Lines	EB MAGALONA -BAROTAC VIEJO 230	230	NEGROS /PANAY
2050	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2050	HVDC	LVIP HVDC Link		
2050	HVDC	MVIP HVDC Link		
2050	Reactive Support	Reactive Support		
2035	Rebuild	CORELLA - MARIBOJOC CTS 230	230	BOHOL
2035	Rebuild	CORELLA - UBAY 230	230	BOHOL
2035	Rebuild	CORELLA - UBAY 230	230	BOHOL
2035	Rebuild	UMAPAD - PUSOK 230	230	CEBU
2035	Rebuild	CEBU - BOBON 230	230	CEBU
2035	Rebuild	LUDO - CORDOVA 230	230	CEBU
2035	Rebuild	MAGDUGO - CALONGCALONG 138	138	CEBU
2035	Rebuild	CEBU - UMAPAD 230	230	CEBU
2035	Rebuild	COMPOSTELA - CEBU 138	138	CEBU
2035	Rebuild	DANAO - BOBON 230	230	CEBU
2035	Rebuild	DANAO - TALISAY 230	230	CEBU
2035	Rebuild	ARGAO CTS - DUMANJUG 230	230	CEBU
2035	Replace Transformers	CALONGCALONG 138/69	138/69	CEBU
2035	Replace Transformers	COMPOSTELA 230/138	230/138	CEBU
2035	Replace Transformers	QUIOT 138/69	138/69	CEBU
2035	Rebuild	ORMOC -SUMANGGA 138	138	LEYTE

Target In-service Year	Project Type	Description	kV	District
2035	Rebuild	TGPP - ISABEL 138	138	LEYTE
2035	Rebuild	ORMOC - TUGAS 230	230	LEYTE
2035	New Lines	ORMOC - TUGAS 230	230	LEYTE
2035	Replace Transformers	ISABEL 138/69	138/69	LEYTE
2035	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/ CEBU
2035	New Lines	GUADALUPE - TUGAS 230	230	LEYTE/BOHOL
2035	New Lines	MARIBOJOC CTS - ARGAO CTS 230	230	LEYTE/BOHOL
2035	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2035	Rebuild	PONDOL - AMLAN 138	138	NEGROS
2035	Rebuild	PONDOL - AMLAN 138	138	NEGROS
2035	Rebuild	BACOLOD - CADIZ 138	138	NEGROS
2035	Replace Transformers	AMLAN 138/69	138/69	NEGROS
2035	New Lines	EB MAGALONA -BAROTAC VIEJO 230	230	NEGROS/PANAY
2035	Rebuild	ILOILO - MANDURRIAO 138	138	PANAY
2035	Rebuild	STA BARBARA - MANDURRIAO 138	138	PANAY
2035	Rebuild	DINGLE - BAROTAC VIEJO 138	138	PANAY
2035	Replace Transformers	STA BARBARA 138/69	138/69	PANAY
2035	Replace Transformers	STA BARBARA 230/138	230/138	PANAY
2035	Replace Transformers	MANDURRIAO 138/69	138/69	PANAY
2035	Replace Transformers	SAN JOSE 69	138/69	PANAY
2035	Replace Transformers	CALBAYOG 138/69	138/69	SAMAR
2040	New Lines	DANAO - BOBON 230	230	CEBU
2040	New Lines	DANAO - TALISAY 230	230	CEBU
2040	New Transformer	DUMANJUG 230/138	230/138	CEBU
2040	New Lines	SAMBOAN - PONDOL 138	138	CEBU/NEGROS
2040	New Lines	ORMOC - TUGAS 230	230	LEYTE
2040	New Transformers	ORMOC 230/138	230/138	LEYTE
2040	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/ CEBU
2040	New Lines	GUADALUPE - TUGAS 230	230	LEYTE/BOHOL
2040	New Lines	MARBOJOC CTS - ARGAO CTS 230	230	LEYTE/BOHOL
2040	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2040	New Lines	EB MAGALONA -BAROTAC VIEJO 230	230	NEGROS/PANAY
2045	New Lines	ORMOC - TUGAS 230	230	LEYTE
2045	New Lines	GUADALUPE - TUGAS 230	230	LEYTE/BOHOL
2045	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2050	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2050	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2050	HVDC	LVIP HVDC Link		
2050	HVDC	MVIP HVDC Link		
2050	Reactive Support	Reactive Support		
2035	Rebuild	CORELLA - MARIBOJOC CTS 230	230	BOHOL
2035	Rebuild	DANAO - TALISAY 230	230	CEBU

Target In-service Year	Project Type	Description	kV	District
2035	Rebuild	MAGDUGO - CALONGCALONG 138	138	CEBU
2035	Rebuild	COMPOSTELA - CEBU 138	138	CEBU
2035	Rebuild	ARGAO CTS - DUMANJUG 230	230	CEBU
2035	Replace Transformers	COMPOSTELA 230/138	230/138	CEBU
2035	Replace Transformers	QUIOT 138/69	138/69	CEBU
2035	Replace Transformers	CALONGCALONG 138/69	138/69	CEBU
2035	New Lines	MARIBOJOC CTS - ARGAO CTS 230	230	CEBU/BOHOL
2035	Rebuild	ORMOC - TUGAS 230	230	LEYTE
2035	Replace Transformers	ISABEL 138/69	138/69	LEYTE
2035	Replace Transformers	ISABEL 138/69	138/69	LEYTE
2035	New Lines	TABANGO - DAANBANTAYAN 230	230	LEYTE/CEBU
2035	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2035	Rebuild	ILOILO - MANDURRIAO 138	138	PANAY
2035	Rebuild	STA BARBARA - MANDURRIAO 138	138	PANAY
2035	Replace Transformers	SAN JOSE 69	138/69	PANAY
2035	Replace Transformers	MANDURRIAO 138/69	138/69	PANAY
2035	Replace Transformers	MANDURRIAO 138/69	138/69	PANAY
2035	Replace Transformers	CALBAYOG 138/69	138/69	SAMAR
2040	New Transformer	DUMANJUG 230/138	230/138	CEBU
2040	New Lines	MARIBOJOC CTS - ARGAO CTS 230	230	CEBU/BOHOL
2040	New Lines	TUGAS - TALISAY 230	230	LEYTE/CEBU
2050	HVDC	HVDC		
2050	Reactive Support	Reactive Support		

Significant flexible projects under CES 1 and CES 2 include capacity expansions at selected 230/138 kV substations in Cebu and Panay. For CES 1, additional submarine cables between Cebu and Negros are identified as major flexible reinforcements, driven by wind development in the western islands and the relatively lower MW exchange in the LVIP compared to CES 2. Table 14 summarizes the flexible projects identified for each clean energy scenario.

Table 14 Flexible Transmission Projects – Visayas

Generation Plan	Target In-service Year	Project Type	Description	kV	District
CES 1	2035	Rebuild	TRINIDAD - UBAY 69	69	BOHOL
CES 1	2035	Replace Transformers	MABINAY 138/69	138/69	NEGROS
CES 1	2035	New Lines	TOLEDO CTS - CALATRAVA 230	230	NEGROS/CEBU
CES 1	2035	New Lines	TOLEDO CTS - CALATRAVA 230	230	NEGROS/CEBU
CES 1	2040	New Transformers	CORELLA 230/138	230/138	BOHOL
CES 1	2040	New Lines	CORELLA - UBAY 138	138	BOHOL
CES 1	2040	New Transformers	ORMOC 138/69	138/69	LEYTE
CES 1	2040	Rebuild	EB MAGALONA - CADIZ 230	230	NEGROS
CES 1	2040	Rebuild	CALATRAVA - CADIZ 230	230	NEGROS

Generation Plan	Target In-service Year	Project Type	Description	kV	District
CES 1	2040	New Lines	TOLEDO CTS - CALATRAVA 230	230	NEGROS/CEBU
CES 1	2040	New Lines	TOLEDO CTS - CALATRAVA 230	230	NEGROS/CEBU
CES 1	2040	Rebuild	BORACAY - NABAS 138	138	PANAY
CES 1	2040	New Transformers	PARANAS 138/69	138/69	SAMAR
CES 1	2040	New Transformers	CATARMAN 138/69	138/69	SAMAR
CES 1	2042	Rebuild	MAGDUGO - TOLEDO 230	230	CEBU
CES 1	2042	Rebuild	QUIOT - CEBU 138	138	CEBU
CES 1	2042	Rebuild	QUIOT - COLON 138	138	CEBU
CES 1	2042	Rebuild	BOBON - MAGDUGO 230	230	CEBU
CES 1	2042	Rebuild	COLON - CEBU 138	138	CEBU
CES 1	2042	Rebuild	DUMANJUG - SAMBOAN 138	138	CEBU
CES 1	2042	Rebuild	DAANBANTAYAN - COMPOSTELA 230	230	CEBU
CES 1	2042	Rebuild	MARSHALLING - ORMOC 230	138	LEYTE
CES 1	2042	Rebuild	ISABEL - ORMOC 138	138	LEYTE
CES 1	2045	New Lines	TOLEDO CTS - CALATRAVA 230	230	NEGROS/CEBU
CES 2	2035	Replace Transformers	COLON 138/69	138/69	CEBU
CES 2	2035	Replace Transformers	MAGDUGO 230/138	230/138	CEBU
CES 2	2035	Replace Transformers	CEBU 230/138	230/138	CEBU
CES 2	2035	Replace Transformers	MANDAUE 138/69	138/69	CEBU
CES 2	2035	Replace Transformers	CEBU 138/69	138/69	CEBU
CES 2	2035	Replace Transformers	LARAY 230/69	230/69	LEYTE
CES 2	2035	Rebuild	BACOLOD - 230	230	NEGROS
CES 2	2035	Replace Transformers	BACOLOD2 230/138	230/138	NEGROS
CES 2	2035	Rebuild	BORACAY - UNIDOS 138	138	PANAY
CES 2	2035	Replace Transformers	TIGBAUAN 138/69	138/69	PANAY
CES 2	2035	Replace Transformers	NABAS 230/138	230/138	PANAY
CES 2	2035	Replace Transformers	DINGLE 138/69	138/69	PANAY
CES 2	2035	Replace Transformers	BANGA 138/69	138/69	PANAY
CES 2	2035	Replace Transformers	SAN FERNANDO 230/69	230/69	SAMAR
CES 2	2042	Rebuild	COLON - AYA 138	138	CEBU
CES 2	2042	Rebuild	CEBU - QUIOT 138	138	CEBU
CES 2	2042	Rebuild	MANDAUE - CEBU 138	138	CEBU
CES 2	2042	Rebuild	MAGDUGO - BOBON 230	230	CEBU
CES 2	2042	Rebuild	SAN FERNANDO - DUMANJUG 230	230	CEBU
CES 2	2042	New Lines	BABATNGON - 138	138	LEYTE/SAMAR
CES 2	2042	Rebuild	BABATNGON - STA RITA 138	138	SAMAR
REF	2035	Replace Transformers	SAMBOAN 138/69	138/69	CEBU
REF	2035	Replace Transformers	MAASIN 138/69	138/69	LEYTE
REF	2035	Replace Transformers	EB MAGALONA 230/69	230/69	NEGROS
REF	2035	Replace Transformers	CALATRAVA 230/69	230/69	NEGROS
REF	2035	Replace Transformers	CADIZ 230/138	230/138	NEGROS
REF	2040	Rebuild	CORELLA - UBAY 138	230	BOHOL

Generation Plan	Target In-service Year	Project Type	Description	kV	District
REF	2040	New Transformer	CORELLA 230/138	230/138	BOHOL
REF	2040	Rebuild	BORACAY - UNIDOS 138	138	PANAY
REF	2042	Rebuild	CALONGCALONG - TOLEDO 138	138	CEBU
REF	2042	Rebuild	DAANBANTAYAN - COMPOSTELA 230	230	CEBU
REF	2042	Rebuild	MALITBOG - MARSHALLING 230	230	LEYTE
REF	2042	New Lines	BABATNGON - 138	138	LEYTE/SAMAR
REF	2042	Rebuild	BABATNGON - STA RITA 138	138	SAMAR

4.2.6.3 Mindanao Transmission Projects

Most of the transmission upgrades identified for the Mindanao Grid are classified as robust, as these facilities primarily serve the major load centers in Davao and General Santos, where demand growth is concentrated. The western 230 kV corridor from Lala to Tacurong is expected to require upgrading by 2040 to accommodate the increasing power exchange between the Visayas and Mindanao grids.

Flexible transmission projects under the CES 1 scenario mainly involve upgrades to the 138 kV network, which are needed to support projected load and generation changes by 2040.

Table 15 and Table 16 the robust and flexible projects for the Mindanao grid.

Table 15 Robust Transmission Projects – Mindanao

Target In-Service Year	Project Type	Description	kV	District
2035	Rebuild	KIBAWE - PULANGI 138	138	NCMA
2035	Rebuild	KIBAWE - DAVAO 138	138	NCMA/SEMA
2035	Rebuild	SAN FRANCISCO - ALEGRIA 138	138	NEMA
2035	Rebuild	DAVAO - MAA 138	138	SEMA
2035	Rebuild	DAVAO - BAJADA 138	138	SEMA
2035	Rebuild	MAA - BAJADA 138	138	SEMA
2035	Rebuild	BUNAWAN - DON RAMON 138	138	SEMA
2035	Rebuild	BUNAWAN - AYA 138	138	SEMA
2035	Rebuild	MATANAO - KIDAPAWAN 138	138	SEMA/SWMA
2035	Rebuild	KABACAN - TACURONG 138	138	SWMA
2035	Rebuild	TACURONG - KORONADAL 138	138	SWMA
2035	New Transformer	BUNAWAN 230/138	230/138	SEMA
2035	New Transformer	TAGUM 230/138	230/138	SEMA
2035	New Transformer	GEN. SANTOS 230/138	230/138	SWMA
2040	Rebuild	PITOGO - TUMAGA 138	138	NWMA
2040	Rebuild	ZAMBOANGA - TUMAGA 138	138	NWMA
2040	Rebuild	TAGOLOAN - M. FORTICH 138	138	NCMA

Target In-Service Year	Project Type	Description	kV	District
2040	Rebuild	POI - LAGUINDINGAN 230	230	NWMA/NCMA
2041-2050	Rebuild	BALO-I - NMPC 138	138	LA
2041-2050	Rebuild	LUGAIT - OPOL 138	138	LA/NCMA
2041-2050	Rebuild	BOLO-I - NMPC 138	138	NWMA/LA
2041-2050	Rebuild	POI - BALO-I 230	230	LA
2041-2050	Rebuild	LALA - MALABANG 230	230	NCMA
2050	HVDC	MVIP HVDC Link		
2035	Rebuild	KIBAWE - PULANGI 138	138	NEMA
2035	Rebuild	KIBAWE - DAVAO 138	138	SEMA
2035	Rebuild	SAN FRANCISCO - ALEGRIA 138	138	SEMA
2035	Rebuild	DAVAO - MAA 138	138	SEMA
2035	Rebuild	DAVAO - BAJADA 138	138	SEMA
2035	Rebuild	MAA - BAJADA 138	138	SEMA
2035	Rebuild	BUNAWAN - DON RAMON 138	138	SEMA/SWMA
2035	Rebuild	BUNAWAN - AYA 138	138	SWMA
2035	Rebuild	MATANAO - KIDAPAWAN 138	138	SWMA
2035	Rebuild	KABACAN - TACURONG 138	138	SEMA
2035	Rebuild	TACURONG - KORONADAL 138	138	SEMA
2035	New Transformer	BUNAWAN 230/138	230/138	SWMA
2035	New Transformer	TAGUM 230/138	230/138	NWMA
2035	New Transformer	GEN. SANTOS 230/138	230/138	NWMA
2040	Rebuild	PITOGO - TUMAGA 138	138	NCMA
2040	Rebuild	ZAMBOANGA - TUMAGA 138	138	NWMA/NCMA
2040	Rebuild	TAGOLOAN - M. FORTICH 138	138	LA
2040	Rebuild	POI - LAGUINDINGAN 230	230	LA/NCMA
2040	Rebuild	TACURONG - SULTAN KUDARAT 230	230	SWMA
2041-2050	Rebuild	BALO-I - NMPC 138	138	NWMA/LA
2041-2050	Rebuild	LUGAIT - OPOL 138	138	LA
2041-2050	Rebuild	POI - BALO-I 230	230	NCMA
2041-2050	Rebuild	LALA - MALABANG 230	230	NCMA/SEMA
2041-2050	HVDC	MVIP HVDC Link		

Table 16 Flexible Transmission Projects – Mindanao

Generation Scenario	In-Service Year	Project Type	Description	kV	District
REF	2040	Rebuild	TAGOLOAN - VILLANUEVA 138	138	NCMA
REF	2040	Rebuild	BUTUAN - KINAMLUTAN 138	138	NEMA
REF	2040	Rebuild	TORIL - MATANAO 138	138	SEMA
REF	2040	Rebuild	MACO - BALAMBAN 138	138	SEMA
CES 1	2040	Rebuild	POI - KABACAN 138	138	NWMA/SWMA
CES 1	2040	Rebuild	BALO-I - AGUS 138	138	LA
CES 1	2040	Rebuild	BALO-I - LUGAIT 138	138	LA

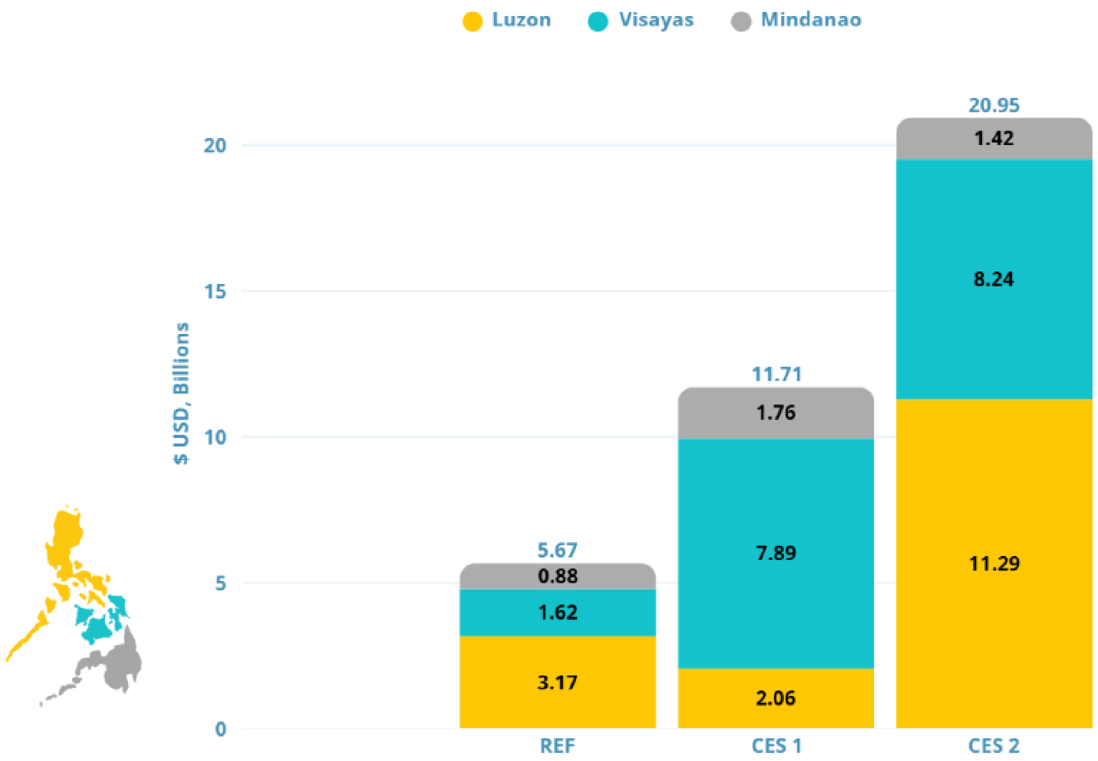
Generation Scenario	In-Service Year	Project Type	Description	kV	District
CES 1	2040	Rebuild	BALO-I - TAGOLOAN 138	138	LA/NCMA
CES 1	2040	Rebuild	JASAAN - VILLANUEVA 138	138	NCMA
CES 1	2040	Rebuild	BUTUAN - KINAMLUTAN 138	138	NEMA
CES 1	2040	Rebuild	TORIL - MATANAO 138	138	SEMA
CES 1	2040	Rebuild	POI - VILLANUEVA 230	230	NWMA/NCMA
CES 1	2040	Rebuild	POI - LAGUINDINGAN 230	230	NWMA/NCMA
CES 1	2040	Rebuild	MALABANG – S. KUDARAT 230	230	LA/SWMA

4.3 Cumulative Horizon Transmission Investment Cost Estimate

Figure 24 presents the total horizon investment cost of transmission projects identified from the economic generation dispatch results under REF, CES 1, and CES 2 scenarios. All cost estimates are expressed in 2025 monetary values, and the resulting investments represent their present value as of 2025.

For the Luzon and Visayas grids, the transition from the REF scenario to CES 2 requires roughly 4 - 5 times more transmission investment. In Mindanao, however, the required investment under CES 2 is only about twice that of the REF scenario. This shows that, based on the economic dispatch results, the Mindanao grid can shift to clean energy with less additional investment compared to the other grids.

Figure 24 Infrastructure Investment Cost Estimate



4.3.1 Infrastructure Expenditure Schedule

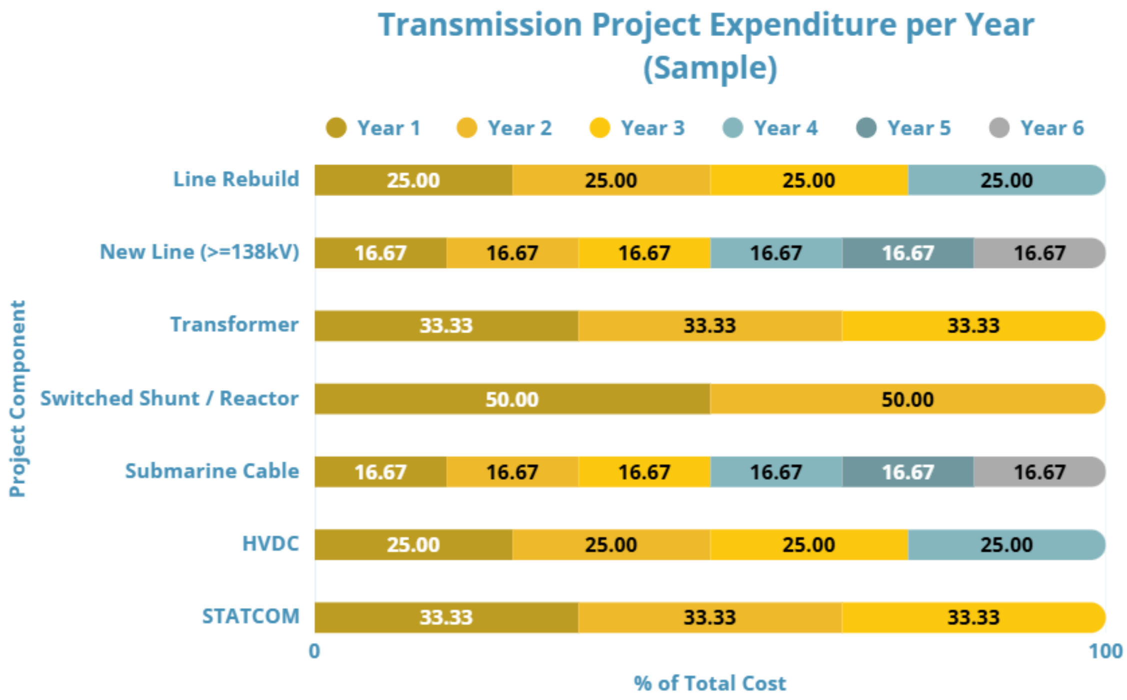
Developing an expenditure schedule aims to help stakeholders anticipate when key investment costs will occur based on project lead times and plan funding accordingly.

In practice, expenditure allocations vary depending on project type, implementation strategy, and procurement progress. Spending typically peaks during the middle years of construction, when major works and equipment deliveries occur, and gradually declines as projects near completion.

In the absence of a detailed financial plan, project expenditures are assumed to follow a uniform distribution across the entire implementation period, as shown in Figure 25.

The uniform expenditure pattern provides an approximate estimate of annual funding requirements and serves mainly as a simplified basis for comparing investment needs across different generation scenarios. However, it does not reflect the detailed timing of individual project expenditures. For more accurate investment planning, the actual disbursement schedule approved by the national regulatory agency should be applied.

Figure 25 Transmission Expenditure Allocation Schedule



4.3.2 Annual Disbursement of Transmission Investments

This section presents the annual spending schedule in nominal terms, showing the value of money for each year of implementation. To account for anticipated changes in construction, materials, and other factors, an annual escalation rate of 5 percent is assumed for this study.

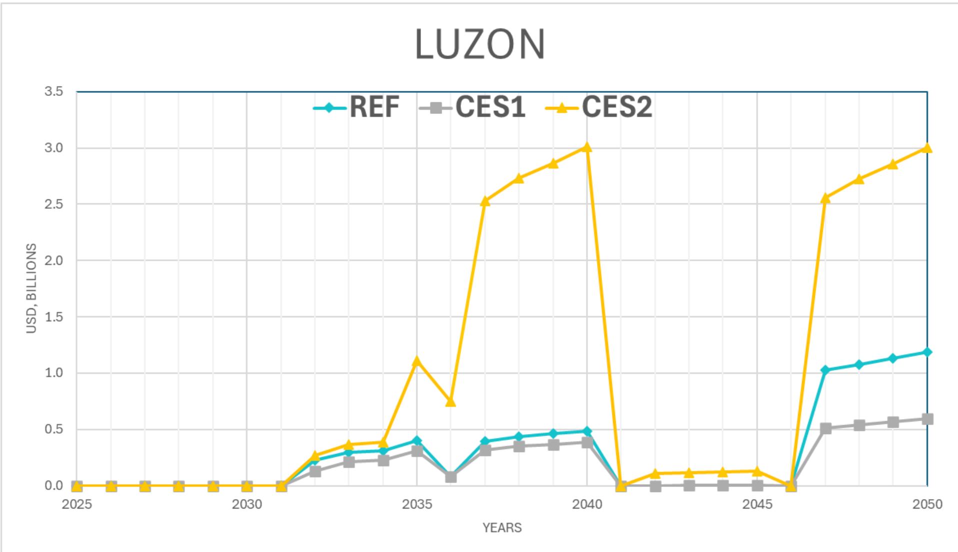
Figure 26 through Figure 28 present the annual disbursement of transmission investments for each grid and the cumulative total for the entire country under different scenarios, based on a uniform expenditure pattern applied throughout the implementation period.

Under this assumption, total project costs are distributed evenly across each project's implementation period, representing a uniform rate of expenditure from start to completion. This approach does not account for variations in spending intensity but provides a consistent basis for estimating how total investments are expected to progress across all transmission projects.

In the medium-term period (2030-2040) of the Luzon grid, as shown in Figure 26, a pronounced deviation is observed in CES 2, where annual expenditures peak over USD 2.5 to 3 billion, significantly higher than REF and CES 1. This sharp increase is attributed to the flexible projects to support the generation plan of CES 2 to ensure system reliability under a higher share of renewable energy. In contrast, REF and CES 1 exhibit relatively stable expenditure profiles in the same period, averaging between USD 0.30–0.50 billion, which shows fewer flexible projects to support these generation plans.

For the horizon period (2041-2050), the main cost driver shifts inter-grid interchange flows through the LVIP HVDC line. The high interchange of power between Luzon and Visayas under CES 2 contributes to the large expenditure, reaching USD 3 billion by 2050. This also necessitates the reinforcement of transmission facilities near the HVDC terminal in Naga substation to accommodate large power transfer.

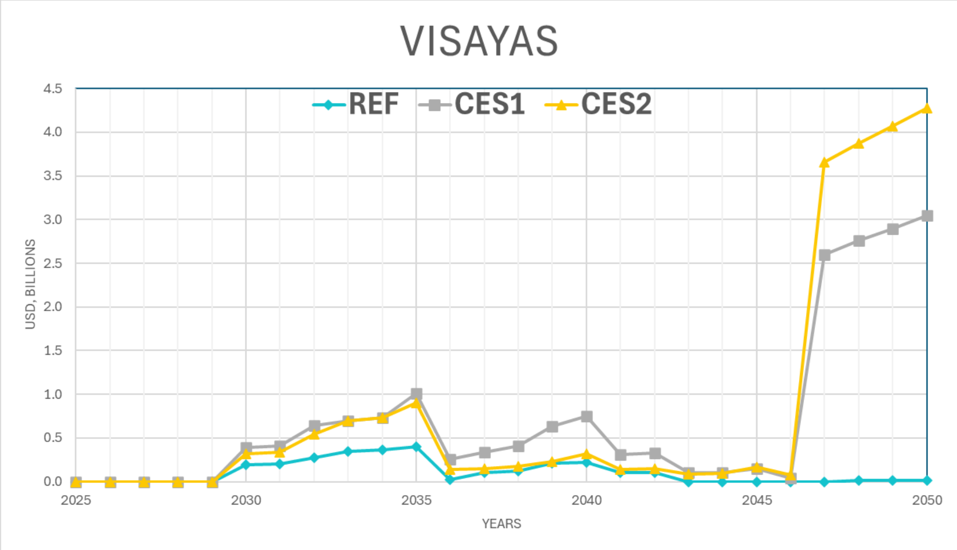
Figure 26 Annual Transmission Investment for the Luzon Grid by Scenario



For Visayas, the medium-term period exhibits steady expenditure growth, with CES 1 and CES 2 reaching around USD 0.60–1 billion annually. In the medium term, CES 2 has slightly more flexible projects than CES 1 to accommodate the generation plan without adversely impacting the Visayas grid.

In the long term, a high expenditure increase is observed in CES 1 and 2, when investments surge up to USD 4 billion in CES 2 and USD 3 billion in CES 1. This escalation is primarily driven by the interchange flows through the LVIP and MVIP. With larger HVDC transfer levels, the reinforcement costs required for the facilities near the HVDC terminals are higher to maintain system reliability. The plot of the annual expenditure for Visayas is shown in Figure 27.

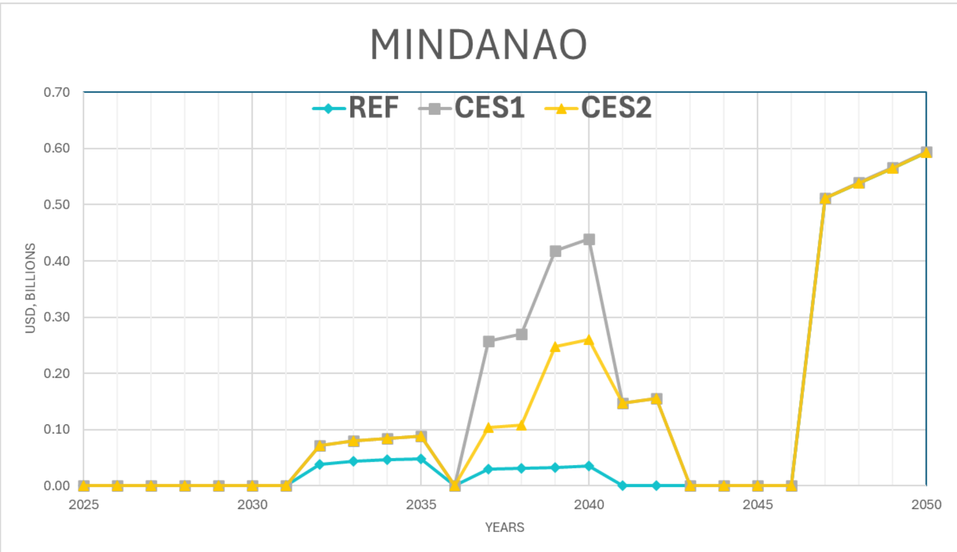
Figure 27 Annual Transmission Investment for the Visayas Grid by Scenario



For Mindanao, the expenditures during the medium-term period under CES 1 and CES 2 increase sharply, peaking at approximately USD 0.40–0.45 billion by 2040, while the REF case remains below USD 0.10 billion. The higher costs for CES 1 and CES 2 are primarily due to the integration of more robust and flexible projects in CES 1 and CES 2 compared to REF. Similar to Luzon and Visayas, these projects address the needs to support the renewable energy generation in CES 1 and CES 2.

In the horizon period, expenditures across all three scenarios begin to rise again due to the higher power transfers through the MVIP HVDC line and transmission upgrades near the HVDC terminal in Lala substation in Lanao del Norte, peaking at around USD 0.60 billion by 2050.

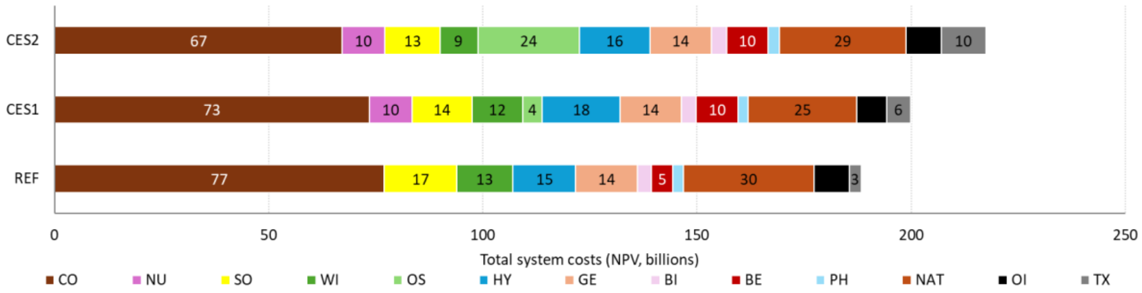
Figure 28 Annual Transmission Investment for the Mindanao Grid by Scenario



5 Levelised Cost of Energy

The levelised cost of energy (LCOE), which includes generation and transmission costs, diverges significantly between the Reference case and Clean Energy Scenarios. The reasons for the differences can be seen in the net present value of total system costs, presented in Figure 29. The main contributors are: (a) significantly higher coal generation costs from maintaining the coal fleet to the end of its technical life, (b) $10 billion in nuclear costs associated with the 4.8 GW nuclear target, (c) up to $24 billion in offshore wind costs, and (d) higher transmission and battery investment costs. Ultimately, the results highlight the cost trade-off between sustainability and cost, assuming reliability and security are maintained.

Figure 29 System Cost Comparison (Net Present Value)



Note: Net present value calculated as of 2026 at a discount rate of 10% pa.

The LCOE presented in the precursory report on BAU and Clean Energy Scenarios is re-presented here with the cost of carbon emissions ($50/t-$CO_2$ and $200/t-$CO_2$) included, allowing a fairer comparison across scenarios. At $50/t-$CO_2$, the trends remain largely unchanged, with the CES2 scenario showing a much higher cost of energy relative to CES1 and the Reference Case, driven by the offshore wind targets. At $200/t-$CO_2$, the high LCOE in 2026 reflects the significant current emissions from coal and natural gas generation in the Philippine system. Over time, the LCOE drops substantially as grid intensity decreases, and the benefits of reduced carbon emissions more than offset the underlying generation cost difference, resulting in lower LCOE in CES1 and CES2 compared with the Reference Case.

Figure 30 Levelised Cost of Energy ($50/t-CO2)

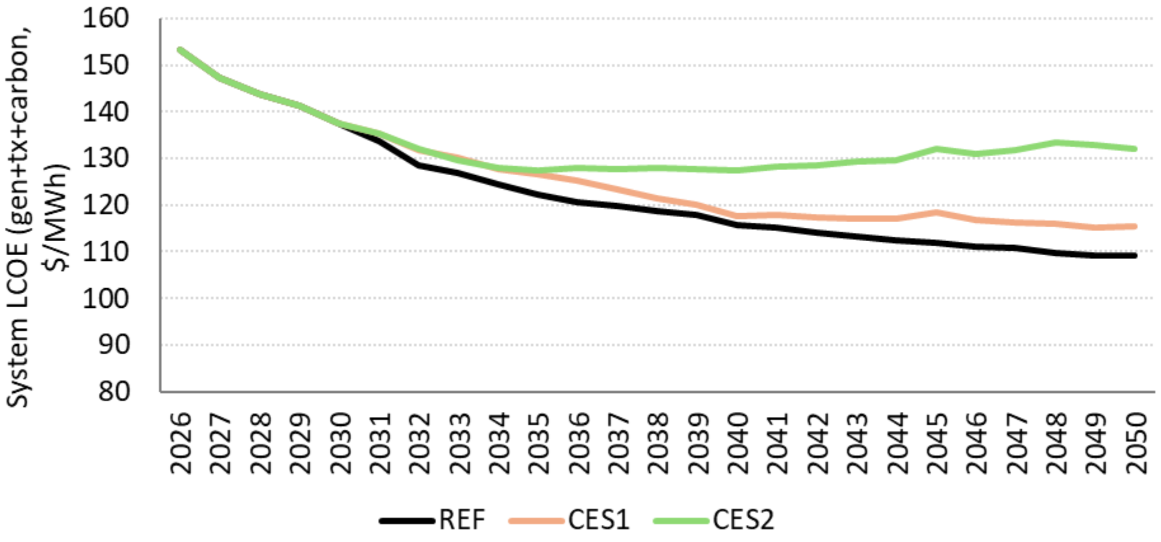
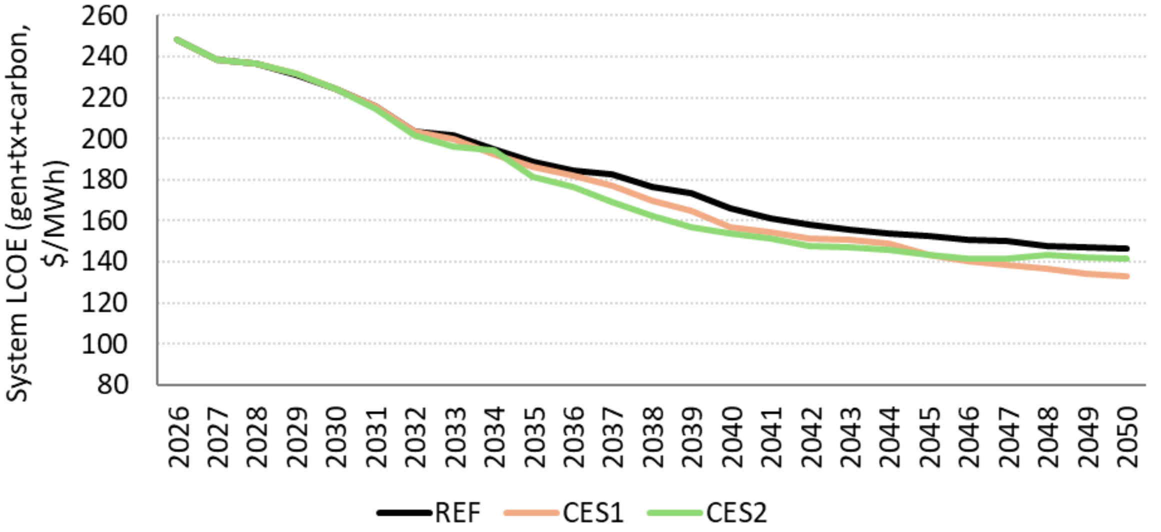


Figure 31 Levelised Cost of Energy ($200/t-CO2)



6 Conclusion

6.1 Generation Investment Planning

The Philippines' energy transition is driving a significant shift in the power system's cost structure, with higher upfront capital expenditure and fixed operation and maintenance costs replacing the variable costs traditionally associated with coal-fired generation. This makes total investment requirements and their timing critical considerations in planning for a sustainable energy future.

The generation investment requirements differ markedly across the Reference Case and Clean Energy Scenarios (CES1 and CES2). By 2050, total generation investment in CES2 reaches $296 billion, more than double the Reference Case ($134 billion), while CES1 requires $219 billion. The divergence begins as early as 2035, primarily due to the introduction of nuclear units ($31 billion by 2050) and significant investment in offshore wind ($129 billion under CES2).

Investment timing is a key driver of these differences. All scenarios require substantial early investments to support renewable deployment and system expansion, with solar, wind, and battery projects needing around $6 billion by 2030 towards the 2040 50% renewable share target and address reserve shortfalls in the near-term. Sustained investment continues throughout the 2030–2050 period to meet demand growth and support system reliability. The Reference Case requires an average of $6 billion per year in generation investment, compared to $11 billion and $14 billion per year for CES1 and CES2, respectively.

CES1 and CES2 involve additional capital-intensive technologies. Nuclear capacity demands $15.5 billion per 2,400 MW across two deployment periods (2031–2035 and 2041–2045). Offshore wind development drives substantial investment in CES1 ($50 billion over 2041–2050) and CES2 ($35 billion per 5-year period in Luzon from 2036, plus $10 billion in the Visayas). CES2 also requires significant investment in battery energy storage (around $6 billion per 5-year period) and long-duration pumped hydro ($9 billion in Luzon).

The Clean Energy Scenarios also include costs associated with early coal retirements, potentially up to $3.6 and $9.1 billion under CES1 and CES2. The overall CES1 and CES2 benefits are evident in the much lower emissions relative to the Reference Case. Assuming a carbon price of $200/t-$CO_2$, CES2 generates a carbon cost saving of $170 billion (undiscounted), which roughly offsets the generation cost difference between the REF and CES2 scenarios, highlighting the economic and environmental rationale for pursuing a more sustainable energy pathway.

Overall, the Clean Energy Scenarios reflect the higher capital intensity of a low-emissions pathway, with early and sustained investment required to achieve ambitious renewable and nuclear deployment targets. The timing and sequencing of investments are critical to ensure system reliability, support renewable integration, and manage costs effectively. The Reference Case represents a more moderate investment trajectory, but all scenarios highlight the need for substantial capital deployment to meet the Philippines' growing electricity demand and energy transition goals.

6.2 Transmission Investment Planning

The infrastructure investment plan presents a structured framework for developing the transmission network. It links the long-term vision with medium-term implementation to ensure that transmission development remains consistent with system needs. The long-term plan identifies the key reinforcements required to accommodate future generation expansion and to support the most reasonable clean energy scenario.

The backbone of robust projects forms the foundation of a reliable and resilient grid, as these are transmission projects that can accommodate any clean energy scenarios. Complementing these are flexible projects, which enhance the grid's ability to adjust to shifts in generation siting, load patterns, and emerging technologies.

The medium-term plan translates the long-term priorities into projects that can be implemented within a 5 to 10-year horizon. This staging approach aligns transmission development with generation entry schedules and load growth, ensuring that key reinforcements are delivered when needed.

For the horizon plan, the transition from the REF scenario to CES 2 in the Luzon and Visayas grids requires about 4 to 5 times more transmission investment. In Mindanao, the investment needed under CES 2 is roughly twice that of the REF scenario. The economic dispatch results indicate that the Mindanao grid can achieve a cleaner energy transition with relatively lower additional investment. The horizon transmission cumulative cost estimates are expressed in 2025 monetary values.

The expenditure schedule complements the staging process by showing how total investments are distributed over the implementation period. Although actual spending will vary depending on project lead times, construction progress, and procurement, a uniform expenditure pattern is assumed for this capacity-building exercise. The estimated annual spending is presented in nominal terms, which differ from the horizon transmission costs, and a 5% escalation rate is applied to reflect expected increases in material and construction costs. The spending schedule approved by the national regulatory agency should be used for more precise financial planning.

The disbursement schedule also shows that investment activities increase gradually from the early years to the medium-term period, as transmission reinforcements must be completed to keep pace with new generation entry and growing demand. Consequently, the medium term reflects the highest concentration of investments. Beyond 2040, investment spending is expected to peak again due to the required series of HVDC links that will support the growing power exchange among the Luzon, Visayas, and Mindanao grids.

The investment roadmap provides direction for implementing transmission projects in a timely and financially sustainable way. Developed in tandem with generation planning, it ensures that transmission development remains aligned with generation expansion and system needs. This coordinated approach supports the acceleration of the country's transition to a cleaner and more reliable power system.

6.3 Governance and Stakeholder Alignment in the Investment Plan

The investment plan guides all stakeholders in bringing the proposed generation and transmission projects into operation. The private sector leads most of the generation investments, especially in renewable energy and flexible resources. Their decisions on where and when new capacity will be built directly influence the timing and priority of transmission reinforcements.

Government agencies such as the DOE and ERC use an investment plan, anchored on the PDP, to frame their policy decisions and regulatory actions. It helps them evaluate project readiness, approve expansion programs, and coordinate generation and transmission development under a consistent national framework that also prioritises sustainability, meaning integrated planning must account for carbon and broader greenhouse gas emission costs.

National Transmission Corporation (TransCo), as the owner of the transmission assets, handles several important roles in the energy sector[12]. It safeguards the national government's interests by ensuring that the concessionaire follows the Concession Agreement and DOE policies. It also handles transmission's right-of-way concerns tied to periods before 2009 and manages system operations for small island grids as mandated by the DOE.

Through the Republic Act No. 9511, TransCo concession was awarded to the NGCP. As the system operator, NGCP is responsible for planning, constructing, managing, operating, and maintaining the national transmission network. NGCP, as a private firm, follows their developed investment plan, which provides them a structured schedule of the transmission reinforcements needed to support incoming generation and expected load growth. This allows NGCP to align its technical planning and project execution with the country's long-term energy direction.

As the DOE welcomed the investment by the Maharlika Investment Corporation in the NGCP, Maharlika paved the way for better coordination between the DOE and the NGCP to help expand transmission connections in a timely manner and speed up the interconnection of country's power grid across the archipelago[13].

Overall, an investment plan shows how quickly projects need to move, how much they are expected to cost, and how different government agencies should work together to reform policy and market incentives to encourage this least-cost development. The investment plan provides everyone a common reference point for making decisions in both generation and transmission planning. This helps ensure that investments are made at the right time and in a coordinated way as the country moves toward cleaner energy.

[12] TransCo's Corporate Profile. https://www.transco.ph/about_us

1.1 [13]DOE. (27 January 2024). *DOE SECRETARY WELCOMES MAHARLIKA INVESTMENT CORPORATION'S INVESTMENT IN NGCP* https://legacy.doe.gov.ph/press-releases/doe-secretary-welcomes-maharlika-investment-corporation%E2%80%99s-investment-ngcp

6.4 Key Findings

Table 17 to Table 22 summarises the key features of the investment plans across the Reference Case and Clean Energy Scenarios.

Table 17 REF Investment Plan

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Capacity addition (MW)	Solar and onshore wind	6,942	19,651	20,904	20,437	11,918
	Offshore wind	0	0	0	0	0
	Nuclear	0	0	0	0	0
	Gas, oil	0	4,084	8,585	11,435	10,991
	Storage	6,115	3,362	1,791	1,711	4,127
	Hydro	0	658	3,064	4,671	4,829
	Geo, Biomass	0	0	0	0	325
	CREZ transmission	5,131	14,389	14,102	11,023	11,415
	Node to node transmission	24	1,634	1,401	7,558	6,185
Coal retirements (MW)	System	0	0	1,428	1,754	257
Investment requirements ($b's)	Solar and onshore wind	5,271	14,183	13,986	12,892	8,978
	Offshore wind	0	0	0	0	0
	Nuclear	0	0	0	0	0
	Gas, oil	0	3,529	9,401	12,139	11,838
	Storage	2,924	1,341	652	580	1,526
	Hydro	0	1,705	7,845	11,615	12,006
	Geo, Biomass	0	0	0	0	1,655
	CREZ transmission	93	267	259	514	563
	Node to node transmission	40	453	543	2,461	2,180
	Total	8,327	21,478	32,687	40,200	38,746
Carbon emissions (Mt-CO2 pa)	Coal	416	429	406	321	321

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
	Oil	0	1	3	9	12
	Gas	5	18	49	104	160
	Total	422	447	459	434	494
	Intensity (t-CO2/MWh)	0.61	0.49	0.39	0.29	0.26
LCOE, $/MWh	No carbon price	114	103	99	99	97
	$50/t	145	127	119	113	110
	$200/t	236	201	177	156	149

Table 18 CES1 Investment Plan

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Capacity addition (MW)	Solar and onshore wind	6,942	10,798	18,078	7,115	16,521
	Offshore wind	0	0	0	9,500	9,500
	Nuclear	0	2,400	0	2,400	0
	Gas, oil	0	3,117	5,220	14,283	12,903
	Storage	6,115	3,662	3,531	3,433	5,291
	Hydro	0	1,979	6,267	2,600	3,380
	Geo, Biomass	0	0	40	0	285
	CREZ transmission	5,131	8,757	16,963	11,359	16,346
	Node to node transmission	25	1,672	2,012	4,067	7,742
Coal retirements (MW)	System	0	1,428	0	5,448	3,211
Investment requirements ($b's)	Solar and onshore wind	5,271	8,836	14,663	3,209	8,894
	Offshore wind	0	0	0	24,416	23,012
	Nuclear	0	16,324	0	15,027	0
	Gas, oil	0	2,174	6,251	13,867	13,812
	Storage	2,924	5,824	5,683	4,552	6,910

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
	Hydro	0	5,126	16,091	6,465	8,404
	Geo, Biomass	0	0	214	0	1,452
	CREZ transmission	93	169	376	136	259
	Node to node transmission	78	879	2,991	2,301	4,072
	Total	8,365	39,332	46,269	69,973	66,816
Carbon emissions (Mt-CO2 pa)	Coal	416	404	352	261	142
	Oil	0	0	1	3	5
	Gas	5	15	30	61	116
	Total	422	419	382	325	264
	Intensity (t-CO2/MWh)	0.61	0.46	0.32	0.22	0.14
LCOE, $/MWh	No carbon price	114	107	105	107	109
	$50/t	145	130	121	118	116
	$200/t	236	199	170	150	137

Table 19 CES2 Investment Plan

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Capacity addition (MW)	Solar and onshore wind	6,942	8,312	1,741	11,271	17,220
	Offshore wind	0	3,125	15,625	15,625	15,625
	Nuclear	0	2,400	0	2,400	0
	Gas, oil	0	3,047	11,111	16,341	3,396
	Storage	6,115	3,617	3,323	5,925	8,750
	Hydro	0	2,006	3,677	1,652	4,750
	Geo, Biomass	0	0	0	0	1,143
	CREZ transmission	5,131	9,467	15,752	16,504	24,962
	Node to node transmission	23	1,691	3,623	8,074	8,430

Metric	Type	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Coal retirements (MW)	System	0	2,075	5,566	6,087	0
Investment requirements ($b's)	Solar and onshore wind	5,271	7,381	837	5,030	11,586
	Offshore wind	0	8,770	42,465	40,157	37,849
	Nuclear	0	16,324	0	15,027	0
	Gas, oil	0	2,124	12,425	16,832	4,371
	Storage	2,924	5,442	4,013	7,310	15,913
	Hydro	0	5,196	9,499	4,107	11,811
	Geo, Biomass	0	0	0	0	4,146
	CREZ transmission	93	161	210	211	659
	Node to node transmission	131	1,548	3,933	7,587	13,007
	Total	8,418	46,946	73,383	96,262	99,342
Carbon emissions (Mt-CO2 pa)	Coal	416	391	230	70	0
	Oil	0	0	4	7	8
	Gas	5	14	47	99	118
	Total	422	405	281	177	126
	Intensity (t-CO2/MWh)	0.61	0.45	0.24	0.12	0.07
LCOE, $/MWh	No carbon price	114	108	116	124	129
	$50/t	145	130	128	129	132
	$200/t	236	197	164	147	142

Appendix A Investment Plan by Region

Table 20 Generation Investment by Region by Type (REF1, USD billions)

PERIOD	REGION	CO	NU	SO	WI	OS	HY	GE	BI	BE	PH	NA	OI	TOTAL
2026-2030	LUZON	0.0	0.0	1.6	2.7	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	6.0
2031-2035	LUZON	0.0	0.0	4.7	6.6	0.0	0.0	0.0	0.0	1.0	0.0	0.8	1.0	14.2
2036-2040	LUZON	0.0	0.0	5.4	5.5	0.0	3.2	0.0	0.0	0.3	0.0	5.9	1.0	21.3
2041-2045	LUZON	0.0	0.0	5.3	4.9	0.0	3.7	0.0	0.0	0.5	0.0	5.6	1.0	21.1
2046-2050	LUZON	0.0	0.0	0.9	2.6	0.0	3.7	1.5	0.0	1.5	0.0	5.3	1.0	16.6
2026-2030	VISAYAS	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1.4
2031-2035	VISAYAS	0.0	0.0	0.8	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.3	3.8
2036-2040	VISAYAS	0.0	0.0	0.8	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.5	5.2
2041-2045	VISAYAS	0.0	0.0	1.3	1.4	0.0	0.0	0.0	0.0	0.0	0.0	3.4	1.9	8.0
2046-2050	VISAYAS	0.0	0.0	0.8	3.9	0.0	0.0	0.2	0.0	0.0	0.0	4.3	0.6	9.8
2026-2030	MINDANAO	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.7
2031-2035	MINDANAO	0.0	0.0	0.7	0.0	0.0	1.7	0.0	0.0	0.3	0.0	0.0	0.0	2.8
2036-2040	MINDANAO	0.0	0.0	0.3	0.0	0.0	4.7	0.0	0.0	0.4	0.0	0.0	0.0	5.4
2041-2045	MINDANAO	0.0	0.0	0.0	0.0	0.0	7.9	0.0	0.0	0.0	0.0	0.0	0.2	8.1
2046-2050	MINDANAO	0.0	0.0	0.7	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	0.6	9.6
2026-2030	SYSTEM	0.0	0.0	2.3	3.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	0.0	8.2
2031-2035	SYSTEM	0.0	0.0	6.2	8.0	0.0	1.7	0.0	0.0	1.3	0.0	1.2	2.3	20.8
2036-2040	SYSTEM	0.0	0.0	6.5	7.5	0.0	7.8	0.0	0.0	0.7	0.0	6.8	2.6	31.9
2041-2045	SYSTEM	0.0	0.0	6.6	6.3	0.0	11.6	0.0	0.0	0.6	0.0	9.0	3.1	37.2
2046-2050	SYSTEM	0.0	0.0	2.4	6.5	0.0	12.0	1.7	0.0	1.5	0.0	9.6	2.2	36.0

Table 21 Generation Investment by Region by Type (CES1, USD billions)

PERIOD	REGION	CO	NU	SO	WI	OS	HY	GE	BI	BE	PH	NA	OI	TOTAL
2026-2030	LUZON	0.0	0.0	1.6	2.7	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	6.0
2031-2035	LUZON	0.0	16.3	2.1	4.7	0.0	0.0	0.0	0.0	4.9	0.0	0.0	0.8	28.9
2036-2040	LUZON	0.0	0.0	3.4	9.1	0.0	3.9	0.0	0.0	5.5	0.0	5.2	1.0	27.9
2041-2045	LUZON	0.0	15.0	2.6	0.0	24.4	3.0	0.0	0.0	3.8	0.0	5.6	1.0	55.3
2046-2050	LUZON	0.0	0.0	4.2	1.5	21.6	3.7	1.5	0.0	5.0	0.0	5.3	1.0	43.8
2026-2030	VISAYAS	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1.4
2031-2035	VISAYAS	0.0	0.0	0.9	1.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	1.3	3.6
2036-2040	VISAYAS	0.0	0.0	0.4	1.9	0.0	0.0	0.2	0.0	0.2	0.0	0.0	0.1	2.7
2041-2045	VISAYAS	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	3.3	6.6
2046-2050	VISAYAS	0.0	0.0	0.6	1.9	1.4	0.0	0.0	0.0	0.7	0.0	4.1	1.2	9.9
2026-2030	MINDANAO	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.7
2031-2035	MINDANAO	0.0	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.7	0.0	0.0	0.0	5.8
2036-2040	MINDANAO	0.0	0.0	0.0	0.0	0.0	12.2	0.0	0.0	0.0	0.0	0.0	0.0	12.2
2041-2045	MINDANAO	0.0	0.0	0.5	0.0	0.0	3.5	0.0	0.0	0.8	0.0	0.0	0.8	5.6
2046-2050	MINDANAO	0.0	0.0	0.8	0.0	0.0	4.7	0.0	0.0	1.2	0.0	1.7	0.5	8.9
2026-2030	SYSTEM	0.0	0.0	2.3	3.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	0.0	8.2
2031-2035	SYSTEM	0.0	16.3	3.0	5.9	0.0	5.1	0.0	0.0	5.8	0.0	0.0	2.2	38.3
2036-2040	SYSTEM	0.0	0.0	3.7	10.9	0.0	16.1	0.2	0.0	5.7	0.0	5.2	1.1	42.9
2041-2045	SYSTEM	0.0	15.0	3.2	0.0	24.4	6.5	0.0	0.0	4.6	0.0	8.8	5.1	67.5
2046-2050	SYSTEM	0.0	0.0	5.5	3.4	23.0	8.4	1.5	0.0	6.9	0.0	11.1	2.7	62.5

Table 22 Generation Investment by Region by Type (CES2, USD billions)

PERIOD	REGION	CO	NU	SO	WI	OS	HY	GE	BI	BE	PH	NA	OI	TOTAL
2026-2030	LUZON	0.0	0.0	1.6	2.7	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	6.0
2031-2035	LUZON	0.0	16.3	1.0	4.3	8.8	0.0	0.0	0.0	4.6	0.0	0.0	1.0	36.0
2036-2040	LUZON	0.0	0.0	0.0	0.0	34.6	3.1	0.0	0.0	1.9	0.0	5.9	1.0	46.6
2041-2045	LUZON	0.0	15.0	4.2	0.0	37.9	0.0	0.0	0.0	6.7	0.0	5.6	1.0	70.5
2046-2050	LUZON	0.0	0.0	2.8	6.1	37.8	3.7	1.5	1.0	5.5	8.5	1.6	0.0	68.6
2026-2030	VISAYAS	0.0	0.0	0.3	0.2	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1.4
2031-2035	VISAYAS	0.0	0.0	0.9	1.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	1.2	3.4
2036-2040	VISAYAS	0.0	0.0	0.4	0.0	7.8	0.0	0.0	0.0	0.4	0.0	3.1	1.9	13.6
2041-2045	VISAYAS	0.0	0.0	0.1	0.0	2.2	0.0	0.0	0.0	0.1	0.0	4.5	3.0	10.0
2046-2050	VISAYAS	0.0	0.0	0.8	0.0	0.0	0.6	0.2	0.5	0.5	0.7	2.2	0.0	5.5
2026-2030	MINDANAO	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.7
2031-2035	MINDANAO	0.0	0.0	0.0	0.0	0.0	5.2	0.0	0.0	0.7	0.0	0.0	0.0	5.9
2036-2040	MINDANAO	0.0	0.0	0.5	0.0	0.0	6.4	0.0	0.0	1.7	0.0	0.3	0.2	9.0
2041-2045	MINDANAO	0.0	0.0	0.7	0.0	0.0	4.1	0.0	0.0	0.5	0.0	1.8	1.0	8.0
2046-2050	MINDANAO	0.0	0.0	0.7	1.2	0.0	7.5	0.2	0.7	0.8	0.0	0.5	0.0	11.6
2026-2030	SYSTEM	0.0	0.0	2.3	3.0	0.0	0.0	0.0	0.0	2.9	0.0	0.0	0.0	8.2
2031-2035	SYSTEM	0.0	16.3	2.0	5.4	8.8	5.2	0.0	0.0	5.4	0.0	0.0	2.1	45.2
2036-2040	SYSTEM	0.0	0.0	0.8	0.0	42.5	9.5	0.0	0.0	4.0	0.0	9.3	3.1	69.2
2041-2045	SYSTEM	0.0	15.0	5.0	0.0	40.2	4.1	0.0	0.0	7.3	0.0	11.9	5.0	88.5
2046-2050	SYSTEM	0.0	0.0	4.3	7.3	37.8	11.8	1.9	2.3	6.8	9.1	4.4	0.0	85.7

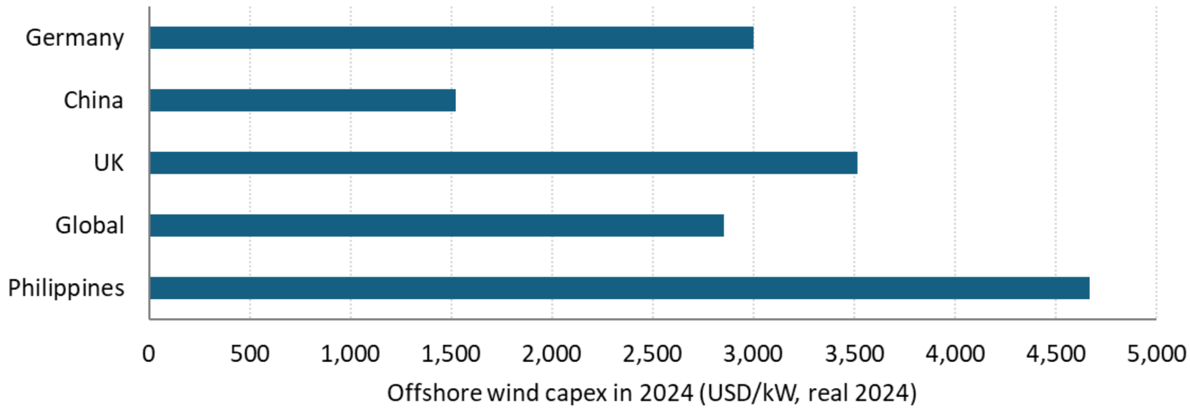
Appendix B Offshore Wind Capex Costs

The recent years have seen significant growth in offshore wind capacities across the world, most notably in China, the UK, and Germany. China has experienced a rapid growth in offshore wind, expanding from only 5 GW in 2018 to over 40 GW in 2025[14]. Currently, about half of the world's total offshore wind capacity is located in China. The UK's grid-connected offshore wind capacity has likewise grown steadily over the past 25 years, reaching 15.9 GW in 2024. Germany has over 9 GW of offshore wind capacity in operation as of June 2025. Higher capacities are expected in the coming years as the country targets at least 30 GW of installed capacity by 2030, as defined in the German Offshore Wind Energy Act[15].

The International Renewable Energy Agency (IRENA) reports that the global weighted average of total installed cost of offshore wind projects declined by 48% from USD 5,518 /kW in 2010 to USD 2,852/kW in 2024. The weighted average CAPEX in China was reported to be at USD 1,520/kW due to its extensive and competitive offshore wind sector. This remains lower than USD 3,514/kW in the UK, underscoring the advantages of growing capacities and larger project pipelines. Germany, on the other hand, experienced the highest decrease of 61% from USD 7,655/kW 2010 to USD 3,000/k in 2024.[16]

As there are currently no offshore wind projects in the Philippines, the actual costs of recent onshore wind projects were taken and scaled by a factor of 2.5 to derive the cost assumption for offshore wind. The scaling factor was adopted from the assumption used in the published USAID CREZ Report. Figure 32 presents the offshore wind CAPEX assumptions used in PLEXOS. The starting value of the CAPEX assumption in 2024 is at USD 4,666/kW, which is 64% higher than the reported global weighted average. A suggested improvement includes reviewing all capex assumptions to ensure alignment with cost conditions in the Philippines.

Figure 32 Offshore Wind Capex in 2024



[14] https://globalenergymonitor.org/wp-content/uploads/2025/06/GEM-China-wind-solar-brief-July-2025.pdf
[15] https://www.offshore-stiftung.de/dokumente/publikationen/Status-of-Offshore-Wind-Energy-Development_First-Half-2024_final.pdf
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