Planning framework and methods to assess possible future high renewable penetrations in emerging economy electricity industries and security, affordability, and environmental implications for Indonesia's Java-Bali grid

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Planning framework and methods to assess possible future high renewable penetrations in emerging economy electricity industries and security, affordability, and environmental implications for Indonesia’s Java-Bali grid

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1. THESIS & TITLE ABSTRACT

Thesis Title

Planning framework and methods to assess possible future high renewable penetrations in emerging economy electricity industries and security, affordability, and environmental implications for Indonesia's Java-Bali grid

Thesis Abstract

Electricity industries worldwide are transitioning away from fossil-fuels towards wind and solar generation. While these technologies are now often cost-competitive as well as environmentally preferrable alternatives to coal and gas options, their highly variable output does raise challenges for delivering secure, affordable, and clean energy. T his is particularly challenging for the electricity industries of emerging economies giving growing demand and limited financial resources.

This thesis aims to address some of the limitations with existing frameworks, methods, and tools for assisting policymakers to plan electricity industry development, with a particular focus on better assessing future electricity generation options for emerging economies.

It uses an open-source evolutionary programming-based optimisation model, National Electricity Market Optimiser (NEMO), to assess future generation options for the cas e study of Indonesia's Java-Bali electricity grid. NEMO can model geographically and temporally variable wind and solar resources and solve least cost generation mixes i n a highly configurable and transparent manner.

A first study assessed the potential industry costs savings possible by recognising the reality of lower reliability standards in emerging economies than often assumed for modelling exercises. Accepting lower reliability outcomes not only reduces industry costs but also supports greater solar and wind deployment, hence better environmental outcomes. Next, the underlying evolutionary programming optimisation of NEMO was used to assess not just the least cost generation mix but the wider solution space, in cluding generation portfolios that deliver total industry costs within 5% of the least cost solution highlighted the wide range of possible technology mixes that could potentia lly deliver a low cost future industry.

Finally, NEMO was used to explore the potential implications of high variable renewable penetrations for operating reserves and hence power system security. The inevita bility of some periods with both low wind and solar availability means that high renewables portfolios still feature significant dispatchable generation capacity. This means t hat the power system will generally have greater levels of operating reserves to cover possible plant failures than mixes with predominantly dispatchable generation. In su mmary, this thesis contributes to better understanding of the challenges and opportunities of deploying possible future high renewables in emerging economy electricity ind ustries.

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> Chapter 6 is based on a peer-reviewed conference paper published in the proceedings of Asia-Pacific Solar Research Conference 2017 titled "Photovoltaic deployment experience and technical potential in Indonesia's Java-Madura-Bali electricity grid". The thesis author is first author, responsible for study design, implementation, and primary drafting, with co-authorship also from A/Prof Iain MacGill, Dr. Anna Bruce and Dr. Navid Haghdadi based on supervision, review, and editing.
>
> Chapter 7 is based on a paper published in Energy journal (Elsevier) titled "Reliability-cost trade-offs for electricity industry planning with high variable renewable energy penetrations in emerging economies: A case study of Indonesia's Java-Bali grid". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship by Dr. Navid Haghdadi, Dr. Anna Bruce and A/Prof. Iain MacGill based on supervision, review, and editing.
>
> Chapter 8 is based on a paper published in Applied Energy (Elsevier) titled "Clustering based assessment of cost, security and environmental trade-offs with possible future electricity generation portfolios". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship also from Dr. Navid Haghdadi, Dr. Anna Bruce and A/Prof Iain MacGill based on supervision, review, and editing.
>
> Chapter 9 is based on a conference paper presented at the 2019 International Conference on Environment and Electrical Engineering (EEEIC), Genoa, Italy and published in IEEEXplore, and later extended into a journal paper published in The Electricity Journal (Elsevier) under the title "Impact of high solar and wind penetrations and different reliability targets on dynamic operating reserves in electricity generation expansion planning". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship also from A/Prof Iain MacGill, Dr. Anna Bruce and Dr. Navid Haghdadi based on supervision, review, and editing.

Candidate's Declaration

✔ **I declare that I have complied with the Thesis Examination Procedure.**

Abstract

Electricity industries worldwide are transitioning away from fossil-fuels towards wind and solar generation. While these technologies are now often cost-competitive as well as environmentally preferrable alternatives to coal and gas options, their highly variable output does raise challenges for delivering secure, affordable, and clean energy. This is particularly challenging for the electricity industries of emerging economies giving growing demand and limited financial resources.

This thesis aims to address some of the limitations with existing frameworks, methods, and tools for assisting policymakers to plan electricity industry development, with a particular focus on better assessing future electricity generation options for emerging economies.

It uses an open-source evolutionary programming-based optimisation model, National Electricity Market Optimiser (NEMO), to assess future generation options for the case study of Indonesia's Java-Bali electricity grid. NEMO can model geographically and temporally variable wind and solar resources and solve least cost generation mixes in a highly configurable and transparent manner.

A first study assessed the potential industry costs savings possible by recognising the reality of lower reliability standards in emerging economies than often assumed for modelling exercises. Accepting lower reliability outcomes not only reduces industry costs but also supports greater solar and wind deployment, hence better environmental outcomes. Next, the underlying evolutionary programming optimisation of NEMO was used to assess not just the least cost generation mix but the wider solution space, including generation portfolios that deliver total industry costs within 5% of the least cost solution highlighted the wide range of possible technology mixes that could potentially deliver a low-cost future industry.

Finally, NEMO was used to explore the potential implications of high variable renewable penetrations for operating reserves and hence power system security. The inevitability of some periods with both low wind and solar availability means that high renewables portfolios still feature significant dispatchable generation capacity. This means that the power system will generally have greater levels of operating reserves to cover possible plant failures than mixes with predominantly dispatchable generation. In summary, this thesis contributes to better understanding of the challenges and opportunities of deploying possible future high renewables in emerging economy electricity industries.

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I am enormously indebted to my supervisors, Iain MacGill, Anna Bruce, and Navid Haghdadi, for their unceasing support, involvement, and encouragement over my PhD study years. I will always be grateful for their innovative insights, thoughtful critics and suggestions, respectful mentorship and patience, generosity with time, dynamic views aiming to help me navigating the research pathway, and of course I have gained a lot more perseverance from them. May the Lord God always bless them and keep them.

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This thesis along with all related research works would not have been possible without financial support. I am thankful for the funding from the Indonesian government via Indonesia Endowment Fund for Education (LPDP) scholarship, including for the scholarship extension due to the unprecedented COVID-19 pandemic. I thank PLN for provisioning the crucial data for the research. I am also grateful for all support from Petra Christian University, Indonesia, and all colleagues at Electrical Engineering Department.

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being so nice since my very first day I moved in. A home far away from home, this charming city has never failed to impress me in so many ways. I hope that one day I can bring kids back to Sydney for their study and living.

It is still fresh in my mind the excitement I had on the first day commencing the PhD. Lately, I have had the mixed, indescribable feelings about finishing the whole things in the weeks, and days leading up to the submission of this thesis. On top of that, I am thrilled and overjoyed to witness God's great love and unfaltering care upon me and my family. *Soli Deo Gloria. Great is Thy faithfulness.*

Publications

Peer-reviewed journal articles (published)

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Peer-reviewed conference papers

Tanoto, Y., Bruce, A., MacGill, I. & Haghdadi, N. Impact of high variable renewable penetrations on dynamic operating reserves in future Indonesian electricity industry scenarios. 19th IEEE International Conference on Environment and Electrical Engineering (EEEIC), Genoa, Italy, 2019.

Tanoto, Y., MacGill, I., Bruce, A. & Haghdadi, N. Photovoltaic deployment experience and technical potential in Indonesia's Java-Madura-Bali electricity grid. Asia Pacific Solar Research Conference, Melbourne, Australia, 2017.

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List of Abbreviations

ADB	Asian Development Bank
AI	Affordability Index
AEMO	Australian Energy Market Operator
ASEAN	Association of Southeast Asian Nations
BAU	Business as Usual
BOT	Build-Operate-Transfer
BOOT	Build-Own-Operate-Transfer
BP	British Petroleum
CEEM	Collaboration on Energy and Environmental Markets
CCGT	Combined Cycle Gas Turbine
CMA-ES	Covariance Matrix Adaptation Evolution Strategy
CP	Carbon Price
CR	Carbon Revenue
DEAP	Distributed Evolutionary Algorithms in Python
DEN	Dewan Energi Nasional
DGE-MEMR	Directorate General of Electricity – Ministry of Energy and Mineral Resources
DOE	Department of Energy
DNI	Direct Normal Irradiance
TIMES	The Integrated MARKAL/EFOM System
EGAT	Electricity Generating Authority of Thailand
EPPO	Energy Policy and Planning Office
ERIA	Economic Research Institute for ASEAN and East Asia
ESMAP	Energy Sector Management Assistance Program
ET	Energy Trilemma
EVN	Vietnam Electricity
GAMS	General Algebraic Modelling System
GDP	Gross Domestic Product
GEP	Generation Expansion Planning
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
GRI	Global Reporting Initiative
GSEE	Global Solar Energy Estimator
HDI	Human Development Index
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
IESR	Institute for Essential Services Reform
IISD	International Institute for Sustainable Development
INDC	Intended Nationally Determined Contributions
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Energy
LDC	Load Duration Curve
LEAP	Long-Range Energy Alternatives Planning System
LOLP	Loss of Load Probability
MARKAL	Market Allocation
MERALCO	Manila Electric Company
MJHR	Ministry of Justice and Human Rights
MFRI	Ministry of Finance Republic Indonesia
NASA	National Aeronautics and Space Administration

NEM	National Electricity Market
NEMO	National Electricity Market Optimiser
NREEC	New, Renewable Energy and Energy Conservation
NREL	National Renewable Energy Laboratory
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Cooperation and Development
OSeMOSYS	Open Source energy Modelling SYStem
PA	Paris Agreement
PEA	Provincial Electricity Authority
PLN	Perusahaan Listrik Negara
PV	Photovoltaic
RE	Renewable Energy
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model
SD	Sustainable Development
SDG	Sustainable Development Goal
SI	Statistics Indonesia
SOM	Self Organising Map
STEC	Suruhanjaya Tenaga Energy Commission
SWI	Shannon-Wiener Index
TIMES	The Integrated Market Allocation/Energy Flow Optimization Model System
UNDP	United Nations Development Programme
USE	Unserved Energy
VRE	Variable Renewable Energy
WEC	World Energy Council
WB	World Bank

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Chapter 1
Introduction

This chapter introduces the thesis at a glance. The problem statement and motivation are presented in Section 1.1, followed by the aim and objectives of thesis in Section 1.2, and research questions and thesis contribution in Section 1.3. Finally, the structure of thesis is elaborated in Section 1.4.

1.1 Problem statement and motivation

Electricity industries worldwide are transitioning away from their present heavy reliance on fossil fuel toward lower carbon generation technologies. A key driver of course are growing concerns about the environmental sustainability of continued fossil fuel use, particularly its contribution to human-made climate change and global warming (Peter, 2019). Key amongst these technologies are the variable renewable energy (VRE) technologies of wind and solar photovoltaics (PV). Their deployment in the electricity industry was driven initially by a number of developed countries through explicit policy support. Now, however, falling costs have made then increasingly well cost competitive as well as environmentally sound. Greater PV and wind deployment is widely recognised as one of the most effective measures for reducing electricity industry emissions (Gielen et al., 2019), and global uptake is growing. Of around 2.5 TW total renewable energy (RE) installed capacity worldwide, Asia has the largest share with around 1.1 TW total capacity in 2019, including around 588 GW of PV and wind – dominated by China, Japan, India, and South Korea. The region and has also consistently achieved the fastest growth, with around 10% capacity additions annually (IRENA, 2020). However, there are some emerging economies in the region that have seen far less progress.

In light of the global objective of limiting the increase of average global surface temperature to below 2°C, and ideally below 1.5°C, adopted within the Paris Agreement in 2015, all electricity industries, including those of emerging economies in Asia, now have a responsibility to participate in ongoing energy sector transition. The good news is that wind and PV is continuing to grow globally, driven by falling costs (IEA, 2019b), improved system design and increasing operational capability to accommodate high variable renewable energy (VRE) penetrations.

While electricity generation from wind and solar is now growing rapidly in jurisdictions other than developed countries, and is being widely incorporated into electricity generation capacity planning studies across the emerging economies (IRENA, 2017a), its highly variable and sometimes unpredictable output does raise challenges for secure and reliable power system operation, particularly given the specific technical challenges of electricity industries in different countries. While high VRE penetrations offer the opportunity to address affordability and environmental sustainability issues in electricity industries, generation capacity planning studies that incorporate high VRE penetrations need to address the impact of VRE short-term intermittency on system reliability and security.

It can be expected that there will be trade-offs between the objectives of affordability, reliability and environmental impacts, and questions of how these might best be measured. A particular complexity is the question of what level of reliability might be reasonably expected, given the cost associated with building more generation to meet higher reliability targets, regardless of the generation mix. This issue is important as emerging economies often struggle with budget constraints when seeking to deliver reliability improvements and capacity expansion to meet growing demand. Environmental objectives may often have a lower priority here as well.

More generally, future electricity industry planning with high VRE penetrations in emerging economies needs to consider and potentially trade-off highly complex choices of the possible future generation portfolios given all the uncertainties of future demand growth, technology costs and wider factors such as future carbon pricing or emissions targets. These uncertainties mean that planning tools that deliver a 'least cost' future generation mix may conceal the breadth of possible solutions of likely similar costs, and perhaps more attractive policy and societal implications. While testing multiple scenarios can go some way to exploring alternative options, this approach is inherently limited by the number of scenarios and sensitivities that can be undertaken in a reasonable amount of time.

Also, there are some possibly quite beneficial outcomes with high variable renewable penetrations for security. The need for sufficient generation capacity to meet demand at all times including during periods of low wind and solar availability means the power system still requires significant levels of dispatchable plant to maintain reliability (Monyei et al., 2019). Might this provide additional operating reserves during the periods of time where renewables are available, to cover possible plant failures - both VRE and with dispatchable plants. Given ongoing demand growth and often tight supply-demand balance this might be particularly useful in emerging economy electricity industries.

This thesis seeks to address the challenges and opportunities that variable renewables offer the electricity industries of emerging economies through the development of methods and tools for planning future generation portfolios including potentially high VRE penetrations.

Indonesia's Java-Bali electricity grid has been selected as a highly relevant case study for most of the planning studies presented in this thesis. The Indonesian government does have an ambitious target of a 23% renewable energy share, equivalent to around 45 GW of renewable generation, in 2025, increasing to a 31% share in 2050 (MEMR, 2014). Although it is the country's largest electricity network, serving most of the population, no utility-scale solar PV and wind generation had been integrated onto the grid until very recently, despite major cost reductions for these technologies over recent years, and significant resource potential, particularly solar, in the region.

The continuing efforts towards successful integration of relatively high VRE penetrations, particularly solar PV and wind, in many developed countries, are a key motivation for this thesis. Despite the very different contexts of nations that have pioneered large-scale VRE grid integration, and while the studies undertaken in this thesis are specific to the Java-Bali grid, its insights into planning for high VRE penetrations have broader relevance to Southeast Asia's emerging economies, and beyond.

1.2 Aim and objectives of the thesis

The aim of this thesis is to better understand the challenges, opportunities, and implications of high VRE penetrations for possible future secure-affordable-low emissions electricity industries in emerging economies.

This aim is elaborated into four research objectives:

1. To determine the status of, and progress towards, more sustainable electricity industries in selected Southeast Asian emerging economies, specifically Indonesia, Malaysia, The Philippines, Thailand, and Vietnam.
2. To identify the potential and impact of high VRE penetrations on possible optimum generation portfolios, using the case study of the Indonesian Java-Bali electricity grid.
3. To understand the impact of incorporating future cost uncertainties of different generation technologies on possible near 'least cost' secure-affordable-low emissions generation portfolios with high VRE penetrations.
4. To assess the impact of deploying high VRE penetrations on system dynamic operating reserves, as backup dispatchable capacity required for periods of low wind and solar to provide significant reserves against possible plant failures for much of the time.

These objectives are further scoped within six research questions in the thesis, considering available data and tools and relevant emerging economy electricity industries in Southeast Asia.

The choice of the Java-Bali grid is based on the experience and expertise of the author on this grid. However, it does represent a useful and relevant case study for considering other electricity industries in the region.

1.3 Research questions and thesis contribution

The six research questions addressed in this thesis are shown in Figure 1.1, along with the conference and journal papers arising from these. The research described in this thesis represents a substantial contribution to the knowledge gaps summarised in Section 1.1. Significant outcomes include:

- a comprehensive review of academic and non-academic literature, legislation and regulations, and available international and Southeast Asian jurisdictional reports to better understand the challenges, barriers, and opportunities for high VRE penetrations in the context of emerging economies' electricity industries,
- development of a novel framework and indicators to assess the status of, and progress towards, more sustainable electricity industries in selected Southeast Asian emerging economies,
- detailed analysis of a dataset of hourly solar PV output across a range of locations within Indonesia's Java-Bali electricity grid, with a focus on the temporal and spatial variability and overall capacity factor of different possible PV plant locations to allow analysis of the possible solar PV contribution in future Indonesia's Java-Bali electricity industry scenarios,
- application and extension of a sophisticated open-source evolutionary algorithm-based optimisation tool, National Electricity Market Optimiser (NEMO), to the case of future planning of Indonesia's Java-Bali electricity grid, incorporating a large set of technical, financial and system demand data,
- detailed analysis of the impact of cost/reliability trade-offs on possible future least-cost generation portfolios with high VRE penetrations,
- application of a new method to assess possible future generation portfolios that have estimated total industry costs relatively close to the 'least cost' generation mix and hence offer possible alternative futures
- application of a new method to assess the impact of high VRE penetrations on system dynamic operating reserves associated with high renewable penetrations.

It is more relevant to note that the contribution of this thesis, since the work was undertaken, is highlighted by the new policy recently announced by the Indonesian government (in May 2021) to push renewables by phasing out coal and introducing carbon price and carbon trading.

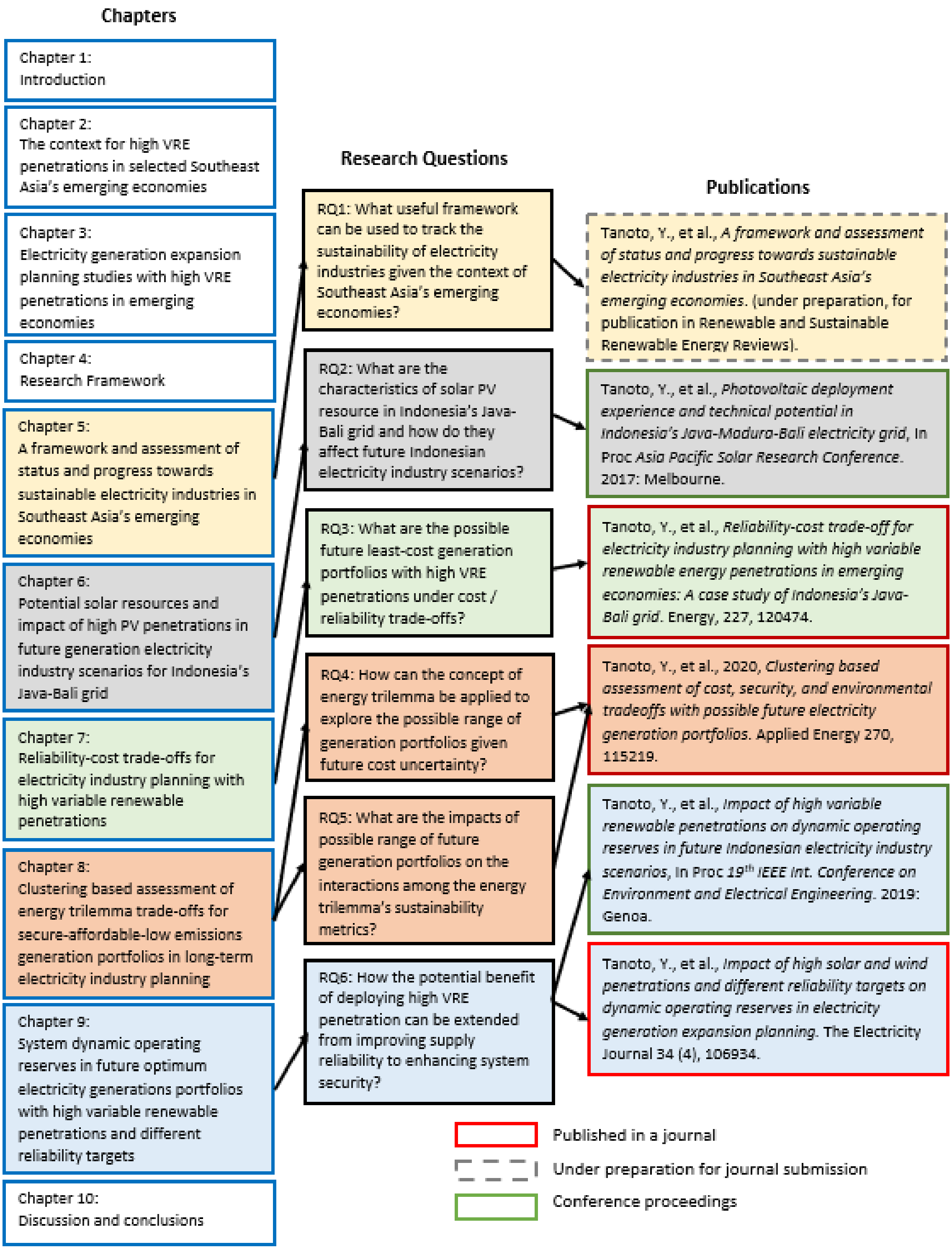


Figure 1.1: Knowledge contribution: mapping research questions, chapters, and publications

Although most of the analyses are focused on the context of Southeast Asia's emerging economies, in particular using the Indonesian Java-Bali electricity industry as a case study, much of the work has greater relevance for many electricity industries in other jurisdictions and can be applied to planning in other national or regional electricity grids, provided relevant data is available.

1.4 Structure of thesis

This thesis contains ten chapters as shown in Figure 1.1. The thesis context is elaborated in **Chapter 2**. This chapter provides a background for high VRE penetrations in selected Southeast Asian emerging economies. This includes an overview of the electricity industry and generation profile, socio-economic and environmental sustainability background, challenges, barriers, and opportunities for integrating high VRE penetrations in sustainable electricity industry planning, and a more focused description of the Indonesian case study, which encompasses multi-dimensional context, and an array of challenges and current drivers.

Existing electricity generation expansion planning studies for high VRE penetrations in emerging economies are presented in **Chapter 3.** This includes reviews of the existing methods, tools, and approaches to conducting studies around long-term electricity generation expansion planning with high VRE penetrations in the context of emerging economies around the world. Additionally, this chapter outlines the knowledge gaps which led to the six research questions presented in the next chapter. **Chapter 4** outlines the framework for the research. This includes an overview of the aim and objectives of the thesis, introduction, elaboration of six research questions and identification of seven research methods that will be used to address the questions.

Chapter 5 presents an assessment of sustainable electricity industries in the context of emerging economies. This chapter specifically provides a critical review of the existing sustainable frameworks and develops a useful sustainability framework and a set of indicators which can be applied to track the sustainability status and progress of the electricity industries in selected Southeast Asian emerging economies, particularly in the current transition period toward more sustainable generation mixes.

The potentials of high VRE penetrations in Indonesian future electricity generation scenarios are examined in **Chapter 6**. This chapter assesses the characteristics and potential impact of PV in Indonesia's Java-Bali electricity grid as a key contributor to future 'least cost' generation scenarios. Wind potential is also considered. The impact of high VRE penetrations on possible optimum generation portfolios are further explored in **Chapter 7**. This chapter particularly assesses the reliability/cost trade-offs on generation planning scenarios as most electricity industries in emerging economies are struggling with improving the system reliability while having some budget constraints and generation technology options. The possible range of least-cost generation portfolios with high VRE penetrations, including wind generation, are simulated using the case study of the 2030 Indonesia's Java-Bali electricity grid.

Chapter 8 presents utilisation of the energy trilemma concept in exploring the broader impact of incorporating high VRE penetrations on future electricity generation planning scenarios. The analysis conducted in this chapter extends the optimisation approach (Chapter 7) from finding only a single optimum generation capacity mix to identifying a range of potential solutions by incorporating uncertainty related to a total industry cost. This is done by allowing simulated least-cost relaxation to analyse possible near-optimum generation portfolios. The analysis involves a clustering-based assessment of cost, security, and environmental trade-offs, using the possible future technologies' capacity of the 2030 Indonesian Java-Bali grid planning scenarios as a case study. The potential impact of possible generation portfolios on the trilemma's key sustainability metrics, which encompass security, economic, and environmental sustainability is examined.

The role extension from supply reliability improvement to system security enhancement through deploying high VRE penetrations is assessed in **Chapter 9.** This chapter presents the potential benefits of high VRE penetrations on system dynamic operating reserves of the electricity industry futures, again using the case study of the projected 2030 Indonesian Java-Bali grid. The analyses are focused on the estimation of the dynamic operating reserves through plotting the reserves curves (obtained from the simulated least-cost generation mixes under various reliability requirements), in addition to exploring the impact on total industry costs and CO_2 emissions reduction of carbon pricing and planned system reserves.

This thesis utilises NEMO, an open-source tool developed in Python, for techno-economic modelling of the least cost electricity generation portfolio in Chapters 6 to 9. Firstly, in Chapter 6, the model is used to for a preliminary exploration of the role of high solar resource penetrations on the 2030 Indonesia's Java-Bali electricity generation planning scenarios. In Chapter 7, a more complex analysis is then conducted to assess the contribution of both solar PV and wind power to the optimum generation portfolios under generation security-affordability trade-offs. Subsequently, in Chapter 8, the model is used to firstly obtain a range of possible near optimum generation portfolios by relaxing total generation's least-costs over different scenarios. Clustering-based assessment is then applied to the multiple generation portfolios output by NEMO. In Chapter 9, the outputs from the NEMO model (hourly generation and possible renewable energy spills over a year), obtained from the optimum 2030 Indonesian

Java-Bali generation capacity mixes, are further analysed to estimate the system dynamic operating reserves through the plot of reserves curves.

Discussion and conclusions are finally presented in **Chapter 10.** This chapter brings together the results of the sustainability assessment and generation portfolio modelling – with the case study of Indonesia's Java-Bali electricity grid – to discuss the opportunity and challenges of high VRE penetrations in the context of emerging economies, particularly through identified potential planning approaches for addressing these challenges. The contribution of this thesis to the knowledge about planning studies on high RE in emerging economies is also summarised and limitations of the work are acknowledged with respect to the research scope and framework. Finally, some concluding remarks are presented to wrap up the thesis.

Chapter 2
The Context for High Variable Renewable Energy Penetrations in Selected Southeast Asia's Emerging Economies

This chapter presents the context for high variable renewable energy (VRE) penetrations in selected Southeast Asian emerging economies, including an overview of the electricity industry and generation profile, socio-economic and environmental sustainability background, challenges, barriers and opportunities for integrating high VRE penetrations in sustainable electricity industry planning, and describes the specific Indonesian multi-dimensional context, including challenges and current drivers.

2.1 Electricity industries in Southeast Asia's emerging economies

2.1.1 Overview of the electricity industry and generation profile

Electricity industries in Southeast Asia's emerging economies, i.e., Indonesia, Thailand, Malaysia, Vietnam, and the Philippines (hereafter referred to as ASEAN-5), are generally monopolised by state-owned companies, either vertically integrated or separate retailers, except in the Philippines' liberalised power sector which includes a wholesale spot market and retail competition. Despite the prevailing structures, electricity industries in ASEAN-5 are characterised by a slowly growing installed generation capacity and increasing dependence on coal. The total installed capacity in the region reached 211 GW in 2018, a 161% increase since 2001. Capacity in Vietnam grew the most amongst these countries during 2001-2018, reaching 43.4 GW in 2018, mainly due to soaring energy demand in the manufacturing sector.

In most ASEAN-5 countries, state-owned generation companies act as single buyers, absorbing bulk electricity supplied by Independent Power Producers (IPPs) to meet generation capacity targets. The role of private investment has been substantial in improving electricity services. Within the region, investment schemes that have allowed private sector participation are generally build-operate-transfer (BOT) or build-own-operate-transfer (BOOT) (ERIA, 2017a). In Indonesia, however, such schemes have been recently removed to encourage more participation by IPPs in investing and developing renewable energy (RE) technology-based electricity generation (MEMR, 2020). The development of electricity industries and RE investment in ASEAN-5, however, is affected by coal dependency as it has dominated the power sector.

Coal dependency has strengthened in most ASEAN-5 countries since 2001, except in Thailand., while the RE share has decreased as coal share increased, particularly in Indonesia and Malaysia, Thailand has succeeded in more than doubling its RE share with a constant coal share for almost two decades since 2001. In the case of the Philippines, the importance of having both coal and gas in the generation capacity mix to replace oil has been highly acknowledged, and their shares have been increased from 2001, despite the absence of local coal and gas resources. In Vietnam, the coal share in electricity generation is planned to rise from 34% in 2017 to 53% by 2030 (Zissler, 2019). For almost two decades, coal and gas have underpinned security of supply in ASEAN-5 countries. High reliance on these fossil fuel-based technologies, especially coal, in the future electricity generation mix is expected for most countries, as reflected in their increased capacity over recent years. Changes in electricity generation shares by fuel in 2001 and 2018 in ASEAN-5 are presented in Figure 2.1, compared with that of Organisation for Economic Co-operation and Development (OECD) countries.

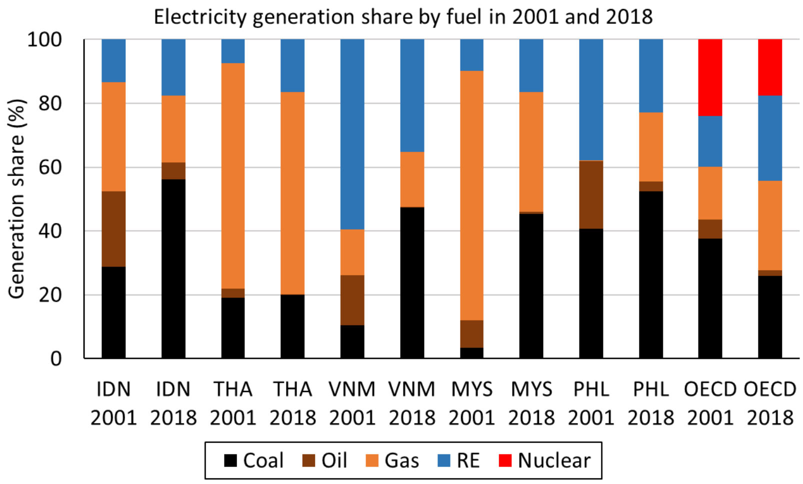


Figure 2.1: Changes in electricity generation shares by fuel in 2001 and 2018 in ASEAN-5 and OECD

ASEAN-5 has a large untapped potential for RE. An excellent solar resource and moderate wind speed – with some areas having higher wind speed – in addition to abundant hydro potential are promising for sustainable electricity industries. The realisable annual potential generation from wind, for example, in Indonesia, Thailand, Vietnam, and the Philippines is approximately 63 TWh, 57 TWh, 45 TWh, and 22 TWh respectively (IEA, 2010). Despite a sharp increase in energy and electricity demand, and while the contribution of large scale, on-grid solar PV and wind in the electricity generation mix is still insignificant in ASEAN-5, Vietnam and Thailand are leading with more than 5 GW and 2 GW total installed solar capacity, respectively, and 375 MW and 1.5 GW of wind in 2019 (IRENA, 2020). This additional variable renewable energy (VRE) based capacity will certainly improve both countries' profile of electricity generation shares by fuel. Collectively, RE production in ASEAN-5 is expected to reach only about 17% by 2025, while the collective target has been initially set at 23% (Khuong et al., 2019). In some countries, RE technologies have also been employed off-grid to accelerate the rate of electrification in rural and remote areas.

As energy access, security (supply reliability) and affordability of energy supplies, and climate change are among the common challenges in ASEAN-5 electricity industries, high-level policies and action plans to support ambitious large-scale RE deployment have been established by each country, mostly over the horizon of 2020 to 2050. While this includes major targets to increase large-scale RE penetrations in electricity generation expansion, only Thailand has explicitly declared a capacity target for solar and the total installed RE capacity has not much changed during 2016-2018 across all these countries, with only a total of 3.5 GW additional capacity in aggregate. Despite installation of significant RE installed capacity in 2016, Vietnam could not avoid a downward trend in the RE share of electricity output during the period, due to increased coal capacity.

2.1.2 Socio-economic background

Robust population increase, rapid urbanisation, high economic growth, and poverty are among the major socio-economic complexities and challenges facing the electricity industry in ASEAN-5. The total population of ASEAN-5 reached 570 million people in 2018 (WB, 2020a), contributing around 87% of the total population of Southeast Asia. Such a large population has brought challenges for electricity industries to meet the growing electricity demand despite solid Gross Domestic Product (GDP) growth for almost two decades. In the human development area, during the last decade, ASEAN-5 has consistently improved Human Development Index (HDI) scores, of which all countries except Vietnam have been classified as high HDI in 2018.

Urbanisation can affect socio-economic development through changes in both patterns and levels of electricity use. The urban population constitutes more than 50% of the total population in all ASEAN-5 countries except for Vietnam (UNDP, 2018). A greater urban population will likely lead to faster electricity demand growth, as the expanded share of a growing middle-class population expects a higher degree of electricity services as well as reliability. It is expected that rising household incomes and higher ownership of appliances will result in a near-tripling of the region's future electricity use (IEA, 2017b).

While electricity reliability is relatively low compared to developed countries and with GDP/capita (current USD) ranging from USD 2,715 (Vietnam) to USD 11,400 (Malaysia) in 2019 (WB, 2020d), poverty is one of the prevalent issues in ASEAN-5 that prevents affected people and communities from accessing electricity. Besides, many others are hindered from enjoying the benefits of uninterrupted use of basic appliances due to affordability issues. Affordable and reliable electricity access, as stipulated in the UN Sustainable Development Goal (SDG) 7, has the potential to alleviate poverty and open employment opportunities (Khandker et al., 2009). Unfortunately , despite a declining poverty trend, around 8 million people in ASEAN-5, mainly in Indonesia and the Philippines, lived without access to electricity in 2018 (WB, 2020c).

2.1.3 Environmental sustainability context

The electricity industry has huge potential to mitigate greenhouse gas emissions as the sector has been acknowledged as the largest contributor to energy-related CO_2 emissions. Coal-fired power plants are the largest emitting sector in ASEAN-5, with almost half of these emissions occurring in Indonesia. While ASEAN-5 emissions are expected to grow significantly in the future due to the domination of fossil-fuel based generation, each country has submitted ambitious targets for reducing emissions – mostly measured against the projected emissions on the business as usual scenario – through the Intended Nationally Determined Contributions (INDC) documents, either unconditional (what a country is planning to do) or conditional (with international assistance) as a response to the Paris Agreement (PA). This is shown in Table 2.1 (ACE, 2017).

Country	Target
Indonesia	29% emissions reduction (unconditional) and 12% additional emissions reduction (conditional) below business as Usual (BAU)
Malaysia	35% reduction on emissions intensity of GDP (unconditional) and 10% additional reduction (conditional)
The Philippines	70% emissions reduction relative to BAU scenario
Thailand	20% emissions reduction (unconditional) and up to 5% additional emissions reduction (conditional) relative to BAU
Vietnam	8% emissions reduction (unconditional) and 17% additional emissions reduction (conditional) relative to BAU

Table 2.1: Energy-related targets on INDC within ASEAN-5 by 2030

The recent status and progress towards more sustainable electricity industries in ASEAN-5 countries, as discussed further in Chapter 5, have been assessed as still falling far behind when compared against necessary emissions reduction targets, as presented in Table 2.1. While the submitted targets have envisaged some ambitious goals regarding the potential deployment of high renewables, there is an urgent for much stronger targets for pursuing deeper decarbonisation by 2050, given worsening climate change impacts and projections. ASEAN-5 countries have a large emissions gap in meeting their PA targets. In aggregate, each country has to reduce its emissions by around 11.7% for unconditional and around 25% conditional, respectively, by 2030, given total baseline emissions of 3,503.7 $MtCO_2$ and 2030 estimated emissions target for unconditional and conditional circumstances of 3,092.4 $MtCO_2$ and 2,616.8 $MtCO_2$, respectively (EPPO, 2018).

To achieve the emissions mitigation target, ASEAN-5 countries have collectively established a target of around 150 GW of RE generation capacity by 2025-2030, compared with an existing capacity of about 50 GW in 2015, with Indonesia and Vietnam having set the most ambitious targets (Cornot-Gandolphe, 2016). However, the most significant challenges to increasing the RE share of generation in the region have been identified as a mixture of techno-economic-socio-governance issues, including inadequate regulatory frameworks and fair pricing systems, high import tariffs on RE technologies, lack of awareness and public support and persistence of subsidies on coal and gas prices to the power sector, in addition to financial and managerial incapability (Khuong et al., 2019), (Nguyen et al., 2019).

2.2 Challenges, barriers, and opportunities for integrating high VRE penetrations in sustainable electricity industry planning

Barriers and their impact on VRE deployment have been classified and discussed in the literature as social, economic, technological, and regulatory barriers (Seetharaman et al., 2019). Technical challenges of VRE integration in the power systems, and the solution technologies available to address these challenges, have been summarised in (Sinsel et al., 2020). Most of the challenges are caused by the different characteristics exhibited by these renewable technologies compared to conventional generation technologies, including output variability, resource uncertainty, local network constraints, non-synchronous and low capacity factor (IEA, 2014), (Seetharaman et al., 2019). These characteristics create challenges in power systems operation, which affect system reliability, being the ability of the available generation mix to meet demand at any given period (Meier, 2014) and security, being the ability of the system to remain robust by providing adequate reserves despite any plant failure (Choukri et al., 2018). Of all available solutions which can be useful to address the challenges, flexible technologies are seen to have the highest potential, while both centralised and distributed technologies are beneficial to overcome stability and local power flow challenges (Sinsel et al., 2020).

Technical and economic challenges of VRE-based generation expansion and short- and long-term solutions are identified and discussed according to the experiences of utility operators worldwide in (WEC, 2016). Uncertainty in forecasting the supply of power is increased with a high degree of solar and wind output variability. Electricity industries, therefore, need to adjust their generation capacity planning and operating strategy to allow smoother integration of a significant share of VRE. Further technical barriers to VRE include those related to availability of supporting infrastructure.

Economic and regulatory barriers to VRE, are interrelated and have a mutual influence. A major existing challenge for developing countries to transition to renewable energy is the preference to construct coal-fired power plants to meet rising demand for cheap electricity (Clark et al., 2020). Strong political support has been shown for coal-fired electricity generation by policymakers through many regulatory frameworks that align with the welfare of the coal industry. Unfair competition between fossil fuel and renewable-based technologies could result from poor and inadequate regulatory frameworks. As discussed above, in Southeast Asia, the use of coal in the power sector has been sustained at a high level (Clark et al., 2020) and coal import for electricity generation has surged between 2000-2015 in many Southeast Asian countries (Cornot-Gandolphe, 2016).

(Sena and Ganguly, 2017) summarised the barriers in terms of market failure, information and awareness, socio-cultural issues and policy. In the context of Southeast Asia's emerging economies, identified barriers for slow deployment of utility-scale VREs include the absence of enabling policies (and, where there are some supporting ones, they are slow with uncertainty around implementation, long and complicated permit application procedures due to overlapping bureaucracies), sustained subsidies on fossil fuel for the electricity sector, and socio-economic as well as political pressures (Erdiwansyah et al., 2019).

While electricity generation from wind and solar has seen a significant increase in developed countries, driven by falling capital costs and enabling policies, opportunities for enhancing energy security, while also reducing the burden of energy subsidies due to reduced fossil fuel use, are opened up.

Ramping up VRE capacity is of course also important not only to enhance energy security but also to meet climate goals without decelerating economic growth or reducing welfare (Sena and Ganguly, 2017). An earlier study revealed that doubling the global share of RE in total final energy consumption, from 18% in 2010 to 36% by 2030, is required, in addition to significant end-use energy efficiency improvements, to limit global temperature increases to below 2°C (IRENA, 2014).

VRE is one of the keys to delivering a sustainable future for the electricity industries of Southeast Asia's emerging economies, with a prediction that two-thirds of electricity generation in 2040 would come from RE, especially hydro, solar, and wind, under the IEA's 'sustainable development scenarios', which are compatible with the goals of mitigating climate change (IEA, 2018). Decarbonisation of the power sector through RE deployment, including VREs, is seen as a key pillar for several countries' environmental strategies (Sena and Ganguly, 2017). The technical potential for solar and wind power throughout Southeast Asia - i.e. strong solar irradiance, averaging over 1,500-2,000 kWh/m2/year with a capacity factor of 20% or more, as well as promising wind resources in some countries – should be a key driver for large scale deployment (Zissler, 2019).

Opportunities to facilitate higher penetrations of utility-scale wind and solar power in many developing countries are significant. However, while most of these countries are currently transitioning their electricity industries toward more sustainable, lower CO_2 emissions pathways, their policymakers could implement a number of strategies to more rapidly overcome the barriers. In the context of developing countries, particularly in Southeast Asia, penetration and scale-up of RE technologies, including wind and solar, require a strong and sustained political commitment that produces a solid regulatory framework to encourage and promote continued attention and focus on deploying these specific generation technologies (Seetharaman et al., 2019). Meanwhile, innovation in electricity industry operation and planning are essential to unlocking current technical barriers and constraints, especially when it comes to the planning stage. (Burke et al., 2019) recommends the following strategies:

- demonstrating political commitment by setting targets and providing attractive investment and international trade regulations,
- deployment policy such as renewable purchase obligations or use of large-scale reverse auctions, and the implementation of a carbon price (Best and Burke, 2018).
- establishment of dedicated agencies including enhancing research and planning capacity,
- incentivising utilities to enhance grid management.

From a planning perspective, the potential of high wind and solar penetrations should be considered in modelling. Given the high cost of stringent reliability settings that are not achieved in practice in developing and emerging economies, especially with high VRE where large capacity investments can be required to reliability meet demand during a small number of low probability weather events, policymakers should consider realistic reliability targets when undertaking future electricity generation planning scenarios.

2.3 The Indonesian context

2.3.1 Socio-economic context

Indonesia is one of the emerging economies in Southeast Asia. The country is currently the largest economy in the region and the world's fourth most populous country, with a GDP and GDP/capita of around USD 1,119 million and USD 4,135, respectively, and a population of over 267 million in 2019 (WB, 2020g), (WB, 2020d), (WB, 2020f). Indonesia has maintained fairly constant economic growth during 2001-2017, with average GDP growth of 5.3%. Indonesia's Human Development Index (HDI) for 2018 was reported at 0.707, which already placed the country in the high human development category (UNDP, 2019). been continuously made, much more improvement is required in this diverse, large archipelago nation of 17,000 islands and more than 300 ethnic groups, as there is still a large gap in terms of the quality of educational, health, and energy services between the economic centres and the rural areas, also between highly and less populated islands in the western and eastern part of the country.

Like many other emerging economies in the region, Indonesia has experienced an increasing urbanisation rate which has created distinct problems around access to decent settlement, health, and energy services. Poverty alleviation has been one of the major focuses of Indonesia. While the country struggles to develop its socio-economic profiles, the poverty rate has been successfully cut by more than half since 1999, to 9.4% in 2019 (WB, 2020e). Given that remarkable achievement, nevertheless, about 25 million people in Indonesia still live below the poverty line, out of a population around 267 million. Such situation hinders this group of people from participating proper education levels and accessing health and energy services amid limited social assistance programs offered by the government.

2.3.2 Energy resources context

Indonesia has been blessed with a large selection of energy resources, especially for fossil fuel-based electricity generation with coal, gas, and now depleted oil. The reserves to production ratio for these three fuels were reported as 67 years, 37.7 years, and 10.7 years, respectively in 2018 (BP, 2019). While the utilisation of these non-renewable sources has been a key for the country's electricity industry development, Indonesia also has RE resources which are currently still underutilised, such as geothermal, hydro, biomass, solar, and wind. The potential opportunities for these resources are reported to be about 29 GW, 75 GW, 33 GW, 1,052 GW and 50 GW, respectively across the archipelago (NREEC, 2017), (Lee et al., 2019).

2.3.3 Institutional context

The Indonesian electricity sector is currently largely vertically integrated and government owned. Generation, transmission, and distribution are largely undertaken by a single state-owned monopoly company, Perusahaan Listrik Negara (PLN). Private sector participation is currently limited to IPPs who generate electricity and sell it to PLN, in its role as the industry's single buyer.

Total national installed capacity was 62.8 GW in 2019, with some 69.8% of capacity owned and operated by PLN, around 27% held by IPPs contracted with PLN, and the remainder of generation capacity rented (PLN, 2020). The Indonesian electricity generation mix in 2019 is coal-dominated, followed by gas, hydro, geothermal, and a few diesel generators. In terms of variable renewables, some insignificant, small-scale grid connected solar PV up to 21 MW has been deployed by PLN, and other 124 MW by IPPs, followed by a total of 154 MW wind farms by 2019, also by IPPs (DGE-MEMR, 2020). In the larger and more populated islands, including Java and Sumatra, electricity has been delivered through large, interconnected grids. Smaller grids in Sulawesi and Kalimantan (Borneo) are planned to be fully interconnected within each island in 2021 and 2023, respectively. Despite Indonesia's geography creating a major challenge for expanding electricity generation capacity and developing networks, the electrification rate has increased from only about 67% in 2010 to 98.3% in 2018 (DGE-MEMR, 2019).

The long-term national electricity industry expansion plan is technically prepared by PLN and published annually on 10 years basis. The specific planning, particularly in terms of infrastructure and investment requirement, is fundamentally referred to the national energy policy, which is jointly established by the government through the Ministry of Energy and Mineral Resources (MEMR), other related agencies including the Indonesian National Energy Council, namely Dewan Energi Nasional (DEN), and the parliament. According to the latest 2019-2028 electricity provisioning planning document, electricity produced from coal will dominate the generation mix in the Java-Bali region and Nusa Tenggara in 2028, with a 57.4% share, followed by gas (24.6%) and combination of renewable energy (17.6%), mainly consisting of hydro (6.5%) and geothermal (8.3%) (MEMR, 2019). Given Nusa Tenggara's insignificant share of national electricity consumption, accounting for less than 2%, this generation mix can be considered as PLN's expectation for the Java-Bali region. It is also suggested from the planning that deployment of significant renewable energy-based capacity, other than geothermal and hydro, would not be prioritised, despite an excellent solar resource and some untapped wind generation potential, and rapidly falling prices for solar photovoltaic systems.

While domination of fossil-fuel-based electricity in the generation mix is projected for the 2028 Indonesian major grid systems in the PLN 2019-2028 planning, which claims to satisfy the reserve margin and renewable energy-based capacity targets, the DEN's Indonesian electricity industry outlook (DEN, 2019) has indicated a different projection for 2050 under its Business as Usual scenario, with renewable energy technologies expected to achieve 46.8% capacity share nationwide, followed by coal and gas with 27.6% and 25.5% capacity share, respectively. Apart from these two different projections, neither document fully addresses important technical indicators in electricity industry planning, such as both short-term and long-term reliability. Besides, the current planning process does not assess the future uncertainty associated with the costs of different generation technologies and fuel resource availability, and the impact of available policy instruments on the future generation mix is not sufficiently discussed.

Indonesia's largest interconnected electricity network, the Java-Bali grid, covers two special regions and five provinces; that is, Jakarta, Yogyakarta, Banten, West Java, Central Java, East Java, and Bali. It served around 179 TWh of electricity consumption in 2019 – equivalent to around 73% of total national consumption, and a 4% increase from 2018 - with a peak demand of 26.7 GW (PLN, 2020). The 2019 generation mix for this grid is dominated by coal (70% of energy mix), followed by gas (23.6%), hydro (3.7%), geothermal (1.9%), and insignificant diesel (0.7%), in addition to unspecified fuel share of 52 TWh purchased energy (PLN, 2020). Until very recently, no utility-scale solar PV and wind generation had been integrated onto the Java-Bali grid despite major cost reductions over recent years for these technologies, and the significant resource potential, particularly solar, of the region. Despite having the highest electrification rate across Indonesian regions, around 600,000 households in Java-Bali were reported to be without access to electricity in 2018 (DGE-MEMR, 2019).

2.3.4 Challenges and current drivers

2.3.4.1 Governance barriers and PLN's long-term planning

Indonesia's current circumstances in the electricity industry requires more attention from stakeholders and policymakers. PLN is currently not financially viable due to the chronic and significant gap between operating expenses, including high generation and capacity cost obligations, and lower operating revenue (IEEFA, 2018). Government electricity subsidies for consumers have been a key factor in rescuing PLN's financial circumstances and enabling the company to record artificially positive yearly income. PLN's financial limitation has been one of the barriers to conducting long-term planning for its large systems. Besides, for many years, there are multi-level bureaucracies outside PLN have been engaged in providing approval and decision for electricity generation expansion plan. In addition, lack of policy support could become a barrier to realise planning targets. As a result, the planning process is perceived as a flawed and also lacking transparency. For example, targets for capacity expansion are not being realised (IEEFA, 2018). While large-scale solar PV and wind are forecast to be the most economic new-build options in the near future and are reshaping the generation mix in many emerging economies, there was no meaningful strategy to incorporate renewable energy options in the 2018-2027 plan (IEEFA, 2018), which includes a significant role for diesel and only a more minor role for solar PV. Consequently, PLN (and government) faces a serious risk of coal lock-in due to its growing exposure to coal IPPs.

Mismatch between targets and realisation of Indonesian long-term generation planning has been affected by both lack of harmonisation and overlapping scope between multi-level governance and authorities. Poor consultation among relevant stakeholders during policy design and establishment has resulted in delayed development progress (Sharvini et al., 2018), representing one of the key barriers to increasing variable renewable penetrations.

2.3.4.2 Regulatory barriers and status of large-scale solar PV and wind turbine deployment

Despite an excellent solar resource, averaging 4.8 kWh/m2/day across the country (PLN, 2017b), significant deployment of grid-connected solar PV has not yet occurred in Indonesia. The International Renewable Energy Agency has estimated that there is some 39 GW of solar PV potential in the Java-Bali area (IRENA, 2017b). Still, by 2015, PLN's national installed capacity of utility-scale PV had reached only 9 MW with no installations in the Java-Bali grid. During 2019, the capacity increased only slightly to 20.1 MW, with no installations in the Java-Bali area. The Indonesian government has encouraged Independent Power Producers (IPPs) to construct and operate such PV plants, and as a result, the non-PLN installed capacity was reported as 124 MW (DGE-MEMR, 2020). As part of the government's plan toward 100% electricity access for the Indonesian people, the limited budget allocated to support PV is mainly directed towards the promotion of off-grid PV to support electricity provision in rural areas and, in particular, reducing diesel consumption on isolated mini-grids.

Despite the limited budget to date, an overall national target of 6.4 GW of PV capacity by 2025 has been set by the government (IRENA, 2017b). Initial support for IPPs involved a government-regulated feed-in tariff up to US$ 0.25/kWh with an additional incentive of $ 0.05c/kWh for PV systems with a minimum of 40% local content (that is, 40% of the overall value of the PV system should be produced locally). Under this framework, the maximum PV capacity allowance for each developer is limited to a maximum of 20% of the regional capacity quota for the tender offer of 10–100 MW (MEMR, 2016). The first stage capacity quota was 150 MW, with a feed-in price of US$ 0.145/kWh for provinces in Java, and 5 MW and US$ 0.16/kWh for Bali provinces. Feed-in prices for other regions varied from US$ 0.15-0.25/kWh (MEMR, 2016). Following a lawsuit brought by the local PV industry over foreign IPPs regarding the local content requirement, the incentive was replaced with a different framework forcing PLN to buy PV energy from the eligible IPPs. Under this framework, apart from the local content requirement, the feed-in tariff for PV generation ranges from 85%-100% of the PLN regional electricity generation cost, while other rules stipulated in the previous framework remain active.

Progress on larger utility-scale solar PV penetration has been slow relative to the established target. PLN opened a tender in the first half of 2017 for 168 MW of PV capacity (Singgih, 2017), in addition to 87 MW of recently planned capacity (PLN, 2017b) in Sumatra. Nevertheless, this capacity is only a small fraction of the 6.4 GW utility-scale PV goal for Indonesia over the next 10 years, and the long-term policy for achieving this is as yet unclear. While the status and progress of many past tenders remain unclear, other tenders have been opened in 2019, including a total of 50 MW PV plants located in western and eastern Bali (IESR, 2019b), and some other smaller capacities. The situation for wind power development is similar, despite the availability of wind turbine technology that works well with the modest to somewhat high wind potential in many Indonesian locations (A/S, 2017). As mentioned earlier in section 2.3.2, no large utility-scale wind farms were developed until a breakthrough project of 75 MW located in Sidrap, South Sulawesi (PLN, 2019), and a recently commissioned 60 MW project located in the same island.

In 2020, the Indonesian government removed the requirement that renewable energy-based electricity generation projects be developed under the BOOT scheme and has obliged PLN to purchase electricity from renewables IPPs regardless of their generation capacity (MEMR, 2020). While these changes are intended to underpin integration of more on-grid renewables and increase the bankability of the projects, the financial sustainability of PLN and the unchanging feed-in tariff regime for purchasing electricity from renewables remain challenges in accelerating high variable renewable penetrations, especially of solar PV.

2.3.4.3 Domination of coal

Indonesia's electricity generation mix has been dominated by coal as the country is one of the biggest coal producers and exporters in the world. Without considering the externality cost in long-term planning, coal has been perceived as a cheap source of energy. This reinforced by Indonesia's coal price cap policy, currently at US$ 70 per tonne, in addition to a 25% domestic market obligation, that the government has introduced to keep the electricity tariff low (IESR, 2019a). As a consequence, the competitiveness of solar PV and wind is weakened by this artificial price pressure from domestic coal. Under current economic circumstances, domestic coal demand is projected to increase due to additional coal-based generation capacity planned until the next decade (IISD, 2019). With coal IPPs' cost burden rising, this all suggests a need for more transparency and participation in planning by a wider range of stakeholders, for example, independent academics and industry associations that can represent the views of broader technologies. There is a need to better understand the range of options, particularly with high renewables penetration, given that high fossil fuel options are increasingly risky.

Major key barriers to the transition from coal to large-scale adoption of variable renewables in Indonesia can be classified into technical, economic, governance/regulatory, and social aspects, of which many are related to coal. These include coal's strong market position, regulatory settings that support the coal industry, subsidies to electricity prices and fossil fuels including the Indonesian coal price cap, investment appetite for funding coal-fired power plants, neglect of externality costs, resistance from the utility and unfavourable regulation of renewables relative to coal, grid management challenges, lack of political support for renewables, and land access challenges (Burke et al., 2019), (IISD, 2019). While these barriers to shifting Indonesia's electricity industry from coal continue to exist, future domestic electricity industry demand for coal, especially for the next 10 years, is expected to increase along with the completion of approved large, planned coal-fired power plants projects. This is despite the lately declining demand from China and India - Indonesia's two major coal importers – which are currently aiming for high renewable penetrations (Clark et al., 2020), and with both countries affected by declining economic growth.

2.3.4.4 Climate change mitigation

As presented in Table 2.1, Indonesia has committed to reducing its greenhouse gas emissions by 29% of the Business-as-Usual level in 2030, or by up to 41% with international assistance, as a response to the Paris Agreement. As a major contributor to national emissions (contributing around 40%-60% of the total), the Indonesian electricity industry requires a transition to more renewable energy generation, especially solar PV and wind, in addition to the existing hydropower and geothermal. With solar PV and wind generation capacity remaining below 0.2 GW in 2018, and the total additional capacity of planned solar PV and wind being only 0.9 GW and 0.85 GW respectively for the 2019-2028 plan, variable renewable energy progress has been acknowledged as slower than planned. Despite the competitiveness, and the system emissions reduction benefits, of solar PV and wind, the PLN 10-year plan has not been changed for many years and shows a chronic reliance on ‘artificially cheap’ domestic coal. The plan seems not to fully acknowledge the potential of higher variable renewable penetrations to improve energy security and mitigate climate change and global warming due to fossil fuel-based electricity generation.

Like other countries in the region, the Indonesian government has established a set of high-level policies and action plans to encourage more RE deployment, as a part of the national efforts in mitigating climate change impact. The Government Regulation on National Energy Policy No. 79/2014 has mandated a 23% renewable energy share equivalent to 45.2 GW electricity in 2025 and an increase to 31% share in 2050 (MJHR, 2014). This results in a generation mix target at the end of 2025 of 54.6% coal, 23% renewables, 22% gas, and 0.4% oil (PLN, 2018). Nevertheless, this specific target for RE generation share seems difficult to achieve, given the complexity of governance and other challenges, and in the absence of more renewables-supportive policies, particularly for promoting higher VRE penetrations, and the lack of innovation in electricity generation planning to date.

Just recently in May 2021, PLN announced a long-term plan to catch up with the global race to decarbonise electricity sectors. The road map, which shows promise to address many of the planning issues raised in this chapter, aims for 2060 carbon neutrality by gradually phasing all coal fired power plants out. Subcritical plants of 1 GW will be retired by 2030 and up to 9 GW by 2035. The 10 GW supercritical plants will follow by 2040, while the ultra-supercritical of 29 GW will be gradually out of fleet from 2045 to 2056. Carbon tax and carbon trading have also been included in the government plan within the timeframe to support more renewables, however it is still unclear how the plan will be implemented, especially in terms of the regulatory settings and eligible participants, and reliability and emissions trade-offs will be managed through ongoing planning efforts. With this new policy, nevertheless, it is more relevant to note the value of this thesis for the case study of Indonesian Java-Bali grid with possible high VRE penetrations and carbon price, as it is highlighted in the announcement by the Indonesian government.

This chapter has identified barriers to planning for, and implementation of high renewable penetrations in emerging economies, and specifically in the context of Indonesia. Challenges include governance barriers and utility’s long-term planning, regulatory barriers, slow deployment of variable renewables, domination of coal, and climate change mitigation. These challenges are sought to be addressed by looking at the opportunity offered by VRE on the emerging economy electricity industries through the development of methods and tools for planning future generation portfolios. The next chapter presents a high-level review of the existing methods and tools applied in studies of long-term generation expansion planning with high VRE penetrations in emerging economies, including an overview of the way uncertainties have been considered and handled. Also included is a summary of the detailed and focused literature reviews associated with specific studies described in the later chapters of this thesis. This leads to identification of the knowledge gaps.

Chapter 3
Electricity Generation Expansion Planning Studies with High Variable Renewable Energy Penetrations in Emerging Economies

This chapter presents a high-level review of the different methods, tools, and approaches used in conducting studies around long-term electricity generation expansion planning with high renewable energy penetrations in the context of emerging economies around the world, including the way in which uncertainties have been considered and handled. Additional literature associated directly with studies undertaken in this thesis, which is reviewed in detail in later chapters, is summarised here. In addition, the knowledge gaps are also outlined, leading to establishment of the research aim and objectives, and the construction of research questions in the next chapter.

3.1 Literature review

3.1.1 Methods and tools for GEP with high VRE penetrations

A large number of studies have been carried out on the topic of long-term electricity generation capacity expansion planning (GEP) with large-scale renewable energy (RE) integration. Various optimisation methods and decision-making strategies have been applied to the task of assessing total industry costs, achieved reliability and environmental outcomes, along with exploring management of a range of issues affecting integrating of intermittent RE, such as supply adequacy, flexibility, uncertainties, and externalities (Oree et al., 2017). While novel optimisation-based methods for solving the least cost GEP problem continue to be introduced (Nawaz et al., 2020), a useful review of available models for integrating renewables in GEP is presented by (Dagoumas and Koltsaklis, 2019). These authors grouped the existing models into three categories; optimisation, general or partial equilibrium and so-called alternative models, and presented a comparison of the advantages and disadvantages of particular models in terms of their capabilities for risk assessment, integration of RE, and basic theoretical assumptions.

A more comprehensive study (Ringkjøb et al., 2018) gathered and discussed a large number of either commercial or open-source modelling tools for analysing energy and electricity systems, including long-term generation planning with a high share of variable renewable energy (VRE). The tools assessed in this study were classified according to their capability, purpose, approach, methodology, temporal resolution, modelling horizon and geographical coverage. The study also specifically aimed to critically review these tools based on how they addressed modelling challenges including future needs, representation of variability, and transparency and validation of results.

To date, however, relatively few studies have assessed high VRE penetrations in the context of emerging economy and developing countries' electricity industry planning. While conducting their assessment using various well-known tools, most of these studies – in regions such as Southeast Asia, South Asia, Central America, South America, Middle East, and Africa - have focused only on determining the optimum generation mix under various possible supply-demand scenarios. These scenarios are generally based around specific resource allocation and generation technology penetration levels, in addition to energy efficiency-based scenarios and Business as Usual (BAU) as a reference. Section 3.1.2 highlights methods, models and scenarios that have been applied in the numerous GEP studies with high VRE penetrations in emerging economies/developing countries around the world.

3.1.2 Studies of GEP with high VRE penetrations in emerging economies

3.1.2.1 Southeast Asia

A General Algebraic Modelling System (GAMS) based multi-objective optimisation model was proposed to assess Indonesia's long-term electricity generation mix by 2050, by incorporating fossil fuel resource-based scenarios in (Purwanto et al., 2015). A Market Allocation (MARKAL) model has been used to assess optimum long-term supply for mitigating CO_2 emissions in Thailand up to 2026 under alternative technology-based scenarios (Pattanapongchai and Limmeechokchai, 2015). The Long-range Energy Alternatives Planning System (LEAP) model has been used to simulate the share of RE capacity in future Indonesian and Thailand electricity industries up to 2050 (Kumar, 2016). The author highlighted implications around CO_2 emissions and electricity production costs by employing different RE penetration scenarios.

The Integrated MARKAL/Energy Flow Optimization Model (EFOM) System (TIMES), a linear programming bottom-up model, has been utilised to analyse the 2050 electricity generation options for Malaysia by examining existing and RE technology-based scenarios (Haiges et al., 2017). Another study has deployed the TIMES model to simulate the impact of various energy policy-based scenarios including the use of renewable portfolio standards (RPS), carbon taxes, subsidies for renewable-based electricity generation, and hard constraints such as maximum coal share in the generation mix, on the Philippines' optimum generation and capacity mix, including solar PV and wind up to 2040 (Mondal et al., 2018).

3.1.2.2 South Asia

The TIMES model has also been applied in a study on long-term power supply scenarios for Bangladesh up to 2045 (Das et al., 2018). The authors focused on assessing the impact of higher RE and high electricity imports and a combination of these two scenarios on future optimum electricity supply options, including VRE. The LEAP model has been used to analyse and discuss the 2015-2050 electricity supply-demand profiles for Pakistan (Mirjat et al., 2018). The authors applied four scenarios comprising energy efficiency and conservation, which represent demand-side measures, two other technology-based scenarios, corresponding to RE and fossil fuel-based technologies, and a reference scenario.

A Combined utilisation of LEAP and EnergyPLAN software has been presented in a study to model GEP in Tamil Nadu, India up to 2030 (Bhuvanesh et al., 2018). The authors used the GHG mitigation scenario results obtained by LEAP analysis, including annual installed capacity additions and electricity production, as inputs to EnergyPLAN. The hourly demand was then calculated, and available installed capacity including VRE was distributed to satisfy the demand.

3.1.2.3 South and Central America

A multi-objective optimisation model has been proposed to assess the 2030 Brazilian GEP problem (Luz et al., 2018). The study suggested a potentially significant capacity share of solar PV in the generation mix as well as other non-hydro renewables. Another study for the Brazilian context has been conducted by applying the EnergyPLAN model and considering electricity export and imports (Dranka and Ferreira, 2018). The authors conducted a simulation with hourly time-steps and analysed three scenarios leading to a possible future 100% renewable electricity system by 2050. Another implementation of the LEAP model was used in a study to develop the 2035 Mexican GEP according to a scenario that combines numerous end-use energy efficiency measures and distributed generation (Grande-Acosta and Islas-Samperio, 2017). The authors also conducted a cost-benefit analysis to evaluate the economic viability of the proposed scenario compared to the results obtained in BAU.

3.1.2.4 Africa

The LEAP model has been used in a GEP study for Ghana up to 2040 (Awopone et al., 2017). The authors proposed a scenario with higher VRE penetrations as well as a more modest one, based on Schwartz's methodology, and compared the results with studies conducted by the government. The economic potential of the proposed scenarios concerning future fuel and technology cost-sensitivity was also emphasised in the study. Another study for Ghana utilised a multi-period stochastic mixed-integer linear programming (MILP) model with budget constraints to determine the optimal generation mix over the planning period up to 2035 (Afful-Dadzie et al., 2017). This study compared installed capacity and yearly unserved demand under different budget constraints. However, only coal, gas and hydro generation technologies were considered in the study.

A GEP study for South Africa's electricity sector to determine a 2050 least cost and decarbonised generation mix was conducted using a MILP model (Wright et al., 2019). The authors co-optimised energy and ancillary services, considering VRE in addition to other renewables, nuclear and storage as candidates. The study found that the least-cost mix, comprised of large-scale VRE plus flexible technologies, had more than 75% RE share, while the decarbonised scenario achieved an even higher RE share. Another study aimed to assess the transition options to 100% RE in South Africa in 2050 (Oyewo et al., 2019). The authors simulated this energy transition using the LUT Energy System Transition Model and found that solar and wind would dominate supply for the proposed 100% RE scenario, indicating a least-cost electricity industry future. The Open Source energy Modelling SYStem (OSeMOSYS), a bottom-up dynamic linear optimisation model, has been applied to unveil renewable energy potential on Tunisian GEP until 2030 (Dhakouani et al., 2017). The authors assessed a 30% RE penetration scenario in the generation mix by incorporating a high VRE share.

3.1.2.5 Middle East

The LEAP model, together with the System Advisor Model (SAM) and EnergyPLAN, was used to simulate a 100% RE based scenario GEP, and compare with mixed fossil-fuel and nuclear scenarios, in Jordan by 2050 (Kiwan and Al-Gharibeh, 2020). The authors first used the LEAP model to obtain future electricity demand, generation capacity and generated energy, cost, emissions, and fuel requirements, as well as the share of indigenous production in the energy mix. SAM was then used to produce hourly RE energy generation. Finally, EnergyPLAN was used to simulate hourly electricity generated over an extended simulation period, and consequent hourly electricity excess and shortage, and then to analyse the impact of storage systems on each technology's dispatchability. The study found that storage is the critical factor for Jordan's 100% renewable electricity industry future.

A linear optimisation model using Excel Solver Optimisation Calculator has been applied to developing different optimal GEP scenarios for Lebanon by 2030 (Wehbe, 2020). The author aimed to investigate various pathways towards a more sustainable electricity industry future, and at the same time examine the level of energy independence by 2030 resulting from the different scenarios considered. Key economic and environmental impacts of these scenarios were then evaluated and compared, including investment cost, the average cost of electricity generated, level of energy imports and carbon emissions.

The LEAP model has been applied to evaluate the impact of different energy policies on the Iranian future electricity demand and supply up to 2040 (Kachoee et al., 2018). By projecting future electricity demand based on an econometric approach, the authors emphasised the potential of mitigating environmental impact and its associated cost to society. The study also included a sensitivity analysis to understand the impacts of input parameter changes on the total industry cost.

3.1.3 Handling uncertainties in GEP

The very large uncertainties involved in undertaking long-term GEP, including future capital and operating costs of different generation technologies as well as demand, if considered at all, have typically been addressed through the use of sensitivity studies or scenario analysis. A few recent studies have included in-depth analysis to identify and model uncertainties relating to the future electricity industry. These studies, however, have focused on probability density approaches and frontier optimal generation mixes. Uncertainties regarding the costs of different generation technologies including coal, Open Cycle Gas Turbine (OCGT), and Combined Cycle Gas Turbine (CCGT) have been modelled to obtain a range of expected generation costs, CO_2 emissions, and associated cost uncertainties for a wide range of potential generation portfolios by using a Monte Carlo simulation platform (Vithayasrichareon and MacGill, 2012). In other work, multiple uncertainties including electricity demand, capacity factor of variable renewables, and environmental policy were considered in exploring the optimal mix of generation technologies using a two-stage stochastic model (DeLuque and Shittu, 2019). Another study considered the capacity factors of variable renewables plus hydro to assess the output probability distribution and generate RE source scenarios, using a Monte Carlo simulation combined with a deterministic generation expansion planning model to find the optimal capacity mix (Santos et al., 2016).

3.2 Summary of detailed review undertaken in this thesis

While the high-level review of the different methods, tools, and techniques used in long-term GEP presented in Sections 3.1.1, 3.1.2, and 3.1.3, gives a broad basis for determining the aim and objectives of this thesis, additional literature relevant to the specific studies undertaken in Chapters 5 to 9 is presented in those chapters. A brief summary of this literature is provided here.

Chapter 5 reviews existing studies and reports which have assessed the sustainability of electricity industries in the context of developing jurisdictions, including in Southeast Asia's emerging economies. This literature has focused on typical sustainability aspects in the electricity industries by using different approaches, including establishment of analytical frameworks and various corresponding criteria.

The literature reviewed in Chapter 6 focuses on solar PV potential assessment in Indonesia. To date, there are only a few existing studies which assess energy generation potential and cost-effectiveness, particularly for grid-connected PV systems, based on the locational and temporal characteristics of solar irradiation across the country.

The literature reviewed in Chapter 7, which includes some of the literature discussed earlier in this chapter (see Sections 3.1.1 and 3.1.2) and other recent studies, elaborates on the use of various methods and tools in studies of future possible optimum electricity generation mixes and their total industry costs and environmental implications under different technology scenarios (including considerably high VRE), technology cost assumptions and possible policy interventions.

Based on the foundation of the high level and detailed reviews undertaken earlier in this chapter and in Chapter 7, the literature review in Chapter 8 further discusses the evaluation of potential trade-offs across the sustainability objectives within the energy trilemma, when considering possible future electricity generation mixes. Some of this literature is focused on the assessment of a single optimum solution under different technical scenarios, and the trade-offs between electrification and CO_2 mitigation.

The literature review presented in Chapter 9 discusses the challenges yet also opportunities of establishing sufficient levels of operating reserves given VRE output characteristics. It further focusses on existing studies that have specifically analysed the impact of wind resource variability and uncertainty on power system operating reserves. This encompasses the challenges of securing sufficiently sized operating reserves, arguments for dynamic reserve requirements and the various methods and models used for setting operating reserves in different jurisdictions.

3.3 Knowledge gaps

While the existing studies presented in Section 3.1 and in Chapters 5 to 9 have provided useful insights and contributed to the knowledge around sustainable long-term electricity GEP, they have mostly emphasised the use of specific optimisation methods to establish the ‘optimal’ generation portfolio through scenarios which allow higher RE utilisation. They have been limited in the degree to which they address not only the major challenges but also the opportunities that emerge from the greater utilisation of wind and solar generation technologies, including for system reliability, expected industry costs and cost uncertainties, and wider planning uncertainties around policy and other potential interventions. This thesis, therefore, seeks to address some key gaps and limitations in the existing literature relating to sustainable electricity long-term GEP, in the context of developing countries. While Chapters 5 to 9 present these limitations in more detail, this section brings together these findings in a high-level manner.

Key gaps and limitations associated with deploying high VRE penetrations encompass a range of issues from assessment frameworks to trade-offs between sustainability objectives, the characterisation of uncertainty associated with different generation mixes, through to implications for system security and reliability.

In the context of emerging economies, there is a lack of studies providing a framework that is not only useful in assessing the high-level sustainability of the electricity industry in a particular country or jurisdiction, but which can also be used to compare countries' respective performances, particularly during the transitional period of shifting from high fossil fuel-intensive generation portfolios to low carbon futures.

Many of the existing studies, for example, regardless of the methods used, have not considered the impact of VRE short-term intermittency (that is, the short-term high variability and only moderate predictability of solar and wind output) over the long-term planning horizon when selecting generation technology candidates and examining their security and reliability outcomes.

While many studies have provided useful information regarding possible future electricity generation mixes and their economic and environmental implications under different scenarios and policy interventions, few have explored the trade-offs between reliability and costs despite these two aspects being seen as major constraints for emerging economies and developing countries. In particular, typical long-term GEP studies in these jurisdictions have still applied very stringent reliability standards that results in higher-cost generation solutions.

Few studies have included in-depth analysis identifying and modelling uncertainties within future electricity GEP studies, focusing instead on the deterministic modelling outcomes. In large part, this is a result of the optimisation methods being applied, which typically seek a single 'lowest' cost solution. This approach, however, can be problematic for exploring the implications of future uncertainties which might mean there is a range of acceptable 'sufficiently low cost' solutions, that involve very different generation mixes.

Integration of large wind and solar raises some challenges in achieving sufficient operating reserves, due to their highly variable and uncertain output, particularly as their contributions increase. While many existing studies of operating reserves have focused on establishing appropriate reserves with respect to the presence of wind, none have assessed the potential impact of deploying high wind and solar penetrations on dynamic operating capacity reserves in the context of future electricity industry scenarios.

The concept of dynamic operating reserves is introduced in this thesis to model and assess the potential impact of VRE penetrations on the temporal variability of capacity reserves of the systems. Operating reserves can and are defined in different ways. The focus here is on reserves that might be called upon with relatively short notice, and how these change over time both as demand and VRE generation varies. These reserves are calculated in terms of excess dispatchable plant generating capacity and any curtailed renewables assessed every 30 minutes to hour. This is further discussed in Chapter 9.

The key gaps and limitations identified here lead to the construction of the thesis aim, objectives, and research questions, along with methods applied to address these questions, as elaborated further in Chapter 4. A more detailed discussion of the specific gaps and limitations to be addressed in this thesis are presented subsequently in Chapters 5 to Chapter 9.

Chapter 4
Research Framework

This chapter presents an overview of the aim and objectives of the thesis. Six research questions are introduced and elaborated, and seven research methods that will be used to address them are subsequently described.

4.1 Aim and objectives

The broad aim of this research can be summarised as follows:

- To better understand the challenges, opportunities, and implications of incorporating high variable renewable energy (VRE) penetrations for possible future secure-affordable-low emissions electricity industries in emerging economies.

The aim is approached through four research objectives as follows:

1. (RO1) To determine the status of, and progress towards, sustainable electricity industries in selected Southeast Asian emerging economies, specifically Indonesia, Malaysia, The Philippines, Thailand, and Vietnam.
2. (RO2) To identify the potential and impact of high VRE penetrations on possible optimum generation portfolios, using the case study of the Indonesian Java-Bali electricity grid.
3. (RO3) To understand the impact of incorporating future cost uncertainties of different generation technologies on possible near 'least cost' secure-affordable-low emissions generation portfolios with high VRE penetrations.
4. (RO4) To assess the impact of deploying high VRE penetrations on system dynamic operating reserves, as backup dispatchable capacity required for periods of low wind and solar to provide significant reserves against possible plant failure for much of the time.

To achieve these objectives, six specific research questions have been established (see Section 4.2), which are addressed by the seven research methods described in Section 4.3.

The relationship between the objectives, research questions and methods, and associated chapters of this thesis is presented in Figure 4.1. Note that the figure excludes Chapter 1: Introduction; Chapter 2: The context for high VRE penetrations in selected Southeast Asia's emerging economies: Chapter 3: Electricity generation expansion planning studies with high VRE penetrations in emerging economies; Chapter 4: Research framework; and Chapter 10: Discussion and Conclusions.

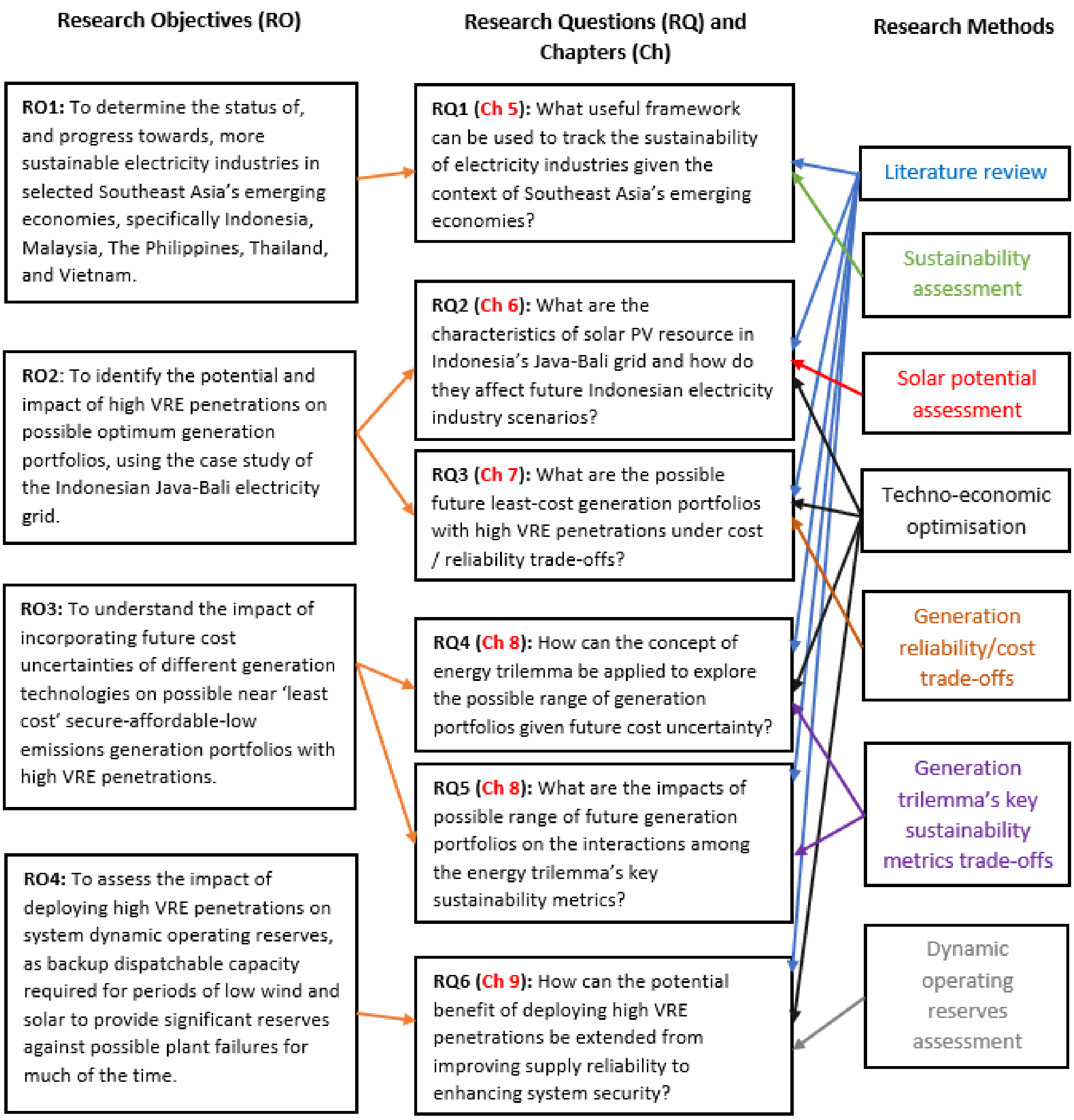


Figure 4.1: Mapping research objectives, research questions and result chapters, and research methods

4.2 Research questions

RQ1. What useful framework can be used to track the sustainability of electricity industries given the context of Southeast Asia's emerging economies?

Electricity industries globally are transitioning from a highly fossil-fuel reliant sector towards more sustainable pathways. This raises challenges and opportunities, including trade-offs between electricity industry sustainability objectives, such as reliability, cost, and environment. Due to the different industry characteristics and priorities of emerging economies, a specific framework may be useful for tracking the status of their electricity sectors against key industry objectives. Where assessment frameworks have been applied, including in the context of Southeast Asia's emerging economies, they have this far had limited sustainability scope, and omission of important indicators and lack of attention paid to the demand side of the industry.

RQ2. What are the characteristics of solar PV resource in Indonesia's Java-Bali grid and how do they affect future Indonesian electricity industry scenarios?

An understanding of PV output characteristics is a key factor for assessing PV integration challenges and opportunities, particularly related to short-term supply reliability and investment decisions. Detailed understanding of PV technical output characteristics is required in order to manage solar output variability and uncertainty over different time frames and is therefore a useful first step in exploring the potential for deploying high penetrations of VRE in electricity industries. Solar resource characteristics in Indonesia's Java-Bali area are therefore analysed in this thesis as a basis for assessing the impact of large-scale utility PV on future Indonesian Java-Bali grid generation expansion planning (GEP).

RQ3. What are the possible future least-cost generation portfolios with high VRE penetrations under cost/reliability trade-offs?

In electricity industry planning, it is arguable that higher reliability can be expected as a result of higher generation costs. Changes to security settings are also considerably cost-sensitive, and in the context of developing countries with financial limitations, may impact energy affordability. An understanding of the implications of different reliability standards, including relatively high unserved energy, on industry costs for future electricity generation portfolios is therefore critical for generation expansion planning in the context of emerging economies. Given the capital cost reductions of renewable energy technologies in recent years, it is also important to understand how different VRE penetrations might affect these cost/reliability trade-offs, particularly given the large uncertainties facing future electricity industries.

RQ4. How can the concept of energy trilemma be applied to explore the possible range of generation portfolios given future cost uncertainty?

Managing the energy trilemma's key objectives in the area of electricity GEP is challenging task, especially in the context of emerging economies. However little attention has been given to use of the energy trilemma concept to explore possible future generation portfolios and the trade-off between competing dimensions of security, cost, and environmental sustainability. In particular, uncertainty in future generation technology costs should be taken into consideration in assessing possible generation portfolios with high VRE that can meet sustainability objectives.

RQ5. What are the impacts of the possible range of future generation portfolios on the interactions among the energy trilemma's key sustainability metrics?

Impacts of future generation portfolios, including with high VRE penetrations on the trilemma's key sustainability metrics, under a range of policy and emissions trajectories has not been widely explored. Since there may be a number of technology mixes that can achieve similar outcomes on key trilemma metrics, but require different policy settings, classification of possible portfolios with similar characteristics and assessment of their outcomes of could help to inform sustainable generation portfolio planning.

RQ6. How can the potential benefit of deploying high VRE penetrations be extended from improving supply reliability to enhancing system security?

Electricity industries generally have some level of generation capacity reserves to cover periods where some of the dispatchable plants might be unavailable due to failure or fuel interruption. High VRE penetrations such as solar and wind reduce the risk of fuel disruption and offer operation and maintenance cost reductions. While solar and particularly wind bring some particular challenges to establishing sufficient operating capacity reserves in power system dynamic operation due to their variability and uncertainty of resources (Holttinen et al., 2012), the excess generation available may also increase available reserves at other times. An understanding of dynamic operating reserves with high VRE penetrations, could be among the important factors to consider for future power system security.

4.3 Research methods

Six research methods have been chosen to address the questions outlined in the previous section. These are described in Section 4.3.1 to 4.3.7 below, while Figure 4.1 shows the mapping between the research objectives, questions and methods and their relation to the chapters of this thesis.

4.3.1 Literature review (Chapter 2 to 9)

The context for the research in this thesis is initially established by reviewing the academic and non- academic literature on challenges and barriers around sustainable energy and electricity industry development in Southeast Asian developing countries, regional renewable energy deployment, and the socio-economic context. This review is presented in Chapter 2, to establish the high-level context for high VRE deployment in the region, and for the research framework presented in this chapter.

Chapter 3 presents a high-level review of the different methods, tools, and approaches used in conducting studies on long-term electricity generation planning with high renewable energy penetrations in the context of emerging economies around the world. The way uncertainties have been considered and handled is also discussed along with a summary of detailed review undertaken in this thesis.

Chapter 5 presents a more detailed, critical review of existing frameworks and indicators used specifically to assess sustainable electricity industries in developing countries, in terms of their usefulness and limitations. This contextual background is key to conducting a comprehensive sustainability assessment, as further described in Section 4.3.2. Important socio-economic development statistics that influence electricity industry development within the observed countries is also reviewed, along with energy resources, environmental sustainability policies, and key profiles and major targets of the electricity industries in this region. A brief review of utility-scale solar PV deployment in the Indonesian electricity industry context, particularly its major Java-Bali grid is presented in Chapter 6, which is then used as the case study in this thesis.

More detailed literature identifying specific research methods and gaps related to reliability settings and their impact on the possible range of generation portfolios, the energy trilemma's key sustainability objectives, and opportunities and challenges relating to establishing system dynamic operating reserves due to the presence of high VRE penetrations are undertaken subsequently in Chapters 7, 8 and 9, respectively, and provide a basis for applying the selected methods in these chapters.

4.3.2 Sustainability assessment (Chapter 5)

The sustainability assessment conducted in this thesis consists of two stages. Firstly, a framework that focuses on both demand and supply side sustainability is developed for assessing electricity industries sustainability across the ASEAN region through a cross-country comparative analysis.

Secondly, this thesis develops a comprehensive set of indicators which combines commonly used existing indicators with new and revised indicators based on available measured time-series data, as well as proposing a number of other important indicators that should be tracked where the data is available. Using the proposed framework, this set of indicators is then applied to a comprehensive comparative analysis of the high-level sustainability status and progress of the electricity industries in the ASEAN-5 during a selected study period.

4.3.3 Techno-economic optimisation modelling (Chapter 6, 7, 8, 9)

While there is considerable optimisation technique focussed work on the literature, and in use in industry, one of the gaps identified in the field of generation expansion planning studies is the challenge of appropriately incorporating uncertainties. This thesis uses an open-source evolutionary programming-based techno-economic optimisation model, NEMO (CEEM, 2018), as one of the main tools for exploring scenarios and conducting analyses, particularly in Chapters 6 and 7, and, with extended functionality, for the analyses in Chapters 8 and 9. Originally developed in Python by Benjamin Elliston at the Collaboration on Energy and Environmental Markets (CEEM), University of New South Wales Sydney, Australia, during his Ph.D. period, the outputs of NEMO include total industry cost, generation capacity mix of selected technologies, total CO_2 emissions, achieved reliability and energy shortage (if any), among others.

Being an open-source tool with a stochastic optimisation algorithm, NEMO provides a useful platform for extending existing research methods. The functionality of NEMO can be expanded as it is suitable to be applied not only as an optimisation tool to assess and analyse the trade-off of least cost generation capacity mixes across multiple objectives, but can also be applied in the identification and modelling of uncertainties in such trade-offs by considering near least-cost mixes through clustering.

For this thesis, the model is operated on an HP Z440 Workstation with 16 Intel Xeon E5-1660 3.0 GHz processors and 64GB of RAM running 64-bit Windows 10. Hourly data comprising 2015 solar and wind generation output traces and real-world 2015 system demand are used as a basis to project 2030 electricity demand for Indonesia’s Java-Bali grid, along with 2030 technology and fuel costs and other relevant parameters that would influence generation dispatch.

4.3.4 Solar potential assessment (Chapter 6)

For this thesis, solar PV potential assessment is carried out to understand PV output characteristics, such as capacity factor, spatial variability (Gueymard and Wilcox, 2011), and hourly output variability (Mills and Wiser, 2010), given the limited existing studies on solar irradiation and PV mapping for the Indonesian context. 1-year, hourly PV power output traces for many locations in Java and Bali for 2015 were obtained from an online RE simulation tool, Renewables Ninja (Pfenninger and Staffell, 2016), and is used to establish a detailed mapping of Indonesia’s Java-Bali solar PV output for 2015. The 2015 mapping is then used to determine an initial set of suitable utility-scale PV locations in long-term generation portfolios of the Java-Bali electricity grid context, especially considering short-term (hourly) solar output variability impact. The potential role of utility-scale PV for a future Java-Bali grid is analysed with respect to the cost uncertainties, projected demand growth, and fuel price scenarios of different generation technologies. Although the methodology and data used in this thesis have potential for further refinement, they are used here to provide an initial high-level estimate of the potential for large scale integration of solar PV in the context of Indonesia's long-term electricity GEP.

4.3.5 Generation reliability/cost trade-offs (Chapter 7)

As discussed above, there is a lack of studies assessing the impact of different reliability settings on the possible range of optimum generation portfolios with high VRE penetrations and the low levels of reliability achieved in many developing countries. Reliability/cost trade-offs can be further explored to provide utilities with better information regarding possible generation portfolios given different reliability standards, enabling them to undertake future electricity GEP within some budget constraints and generation technology options.

This thesis utilises two different methods to obtain a range of optimum generation portfolios and corresponding unserved energy. The first method imposes a series of unserved energy standards as a hard limit in the model, whereas the second method applies different penalty rates for the unserved energy, effectively pricing the unserved energy. The second method provides an alternative way of finding possible least-cost generation portfolios which might allow the algorithm to better search the solution space close to a reliability target.

4.3.6 Analysis of electricity industry trilemma trade-offs with high VRE generation portfolios (Chapter 8)

The potential of high VRE penetrations in managing the three competing objectives of electricity industries in the context of long-term GEP is explored in this thesis, particularly for obtaining possible generation portfolios under the future cost uncertainty of different generation technologies and carbon prices. Using the Java-Bali grid case study, possible generation portfolios are obtained using NEMO by relaxing cost minimisation, i.e., through selecting a set of candidate generation portfolios whose costs fall within 5% of the least cost solution for a predetermined unserved energy limit and carbon price scenario.

The study identifies groups of high and low PV, coal, and gas portfolios within the 5% least cost generation portfolios and then applies clustering techniques to obtain groups of technology mixes with different carbon prices that may have similar industry costs but very different policy implications. For each carbon price, the three associated trilemma parameters of cost, unserved energy and CO2 emissions are analysed and compared for each cluster.

4.3.7 Dynamic operating reserves assessment (Chapter 9)

The impact of high VRE penetrations on the system dynamic operating reserve is analysed and presented using a new approach by first calculating the level of un-dispatched-dispatchable fossil-fuel plants and any curtailed 'surplus' energy generated by VRE on an hourly basis. To visualize the availability of dynamic operating reserves, a load duration curve (LDC) is then presented for year of power system operation and a 2-day moving average of actual operating reserves are also plotted against this for each hour of demand.

The analyses are carried out by firstly simulating the future least-cost generation portfolios in Indonesia's Java-Bali grid with a range of reliability requirements, without a planning reserve constraint, for scenarios both with and without variable renewables, and different carbon prices. In addition to dynamic operating reserves, Total industry costs and CO2 emissions are also analysed for each scenario. Finally, the planning reserve constraint is incorporated in the last set of simulations, such that all hourly demand must be met with no unserved energy, either with or without VRE.

Chapter 5
A Framework and Assessment of Status and Progress towards Sustainable Electricity Industries in Southeast Asia's Emerging Economies

This chapter presents a focussed literature review and develops a framework and a set of indicators to assess the sustainability of electricity industries in selected Southeast Asian emerging economies. Reflecting the basic structure of the industry, the proposed framework covers both supply and demand, to which key sustainability dimensions and objectives are attached, within a context of environmental sustainability. A set of indicators is then established, combining commonly used existing indicators with new and revised ones based on measurable time-series data. These are applied to a comprehensive comparative analysis of the high-level sustainability status and progress of electricity industries across the selected countries. The proposed framework also provides a conceptual framing for this thesis to conduct an in-depth exploration of the interaction between the key objectives of the supply-side sustainability: secure-affordable-low emissions generation.

5.1 Introduction

Electricity industries around the world are transitioning towards renewable energy (RE) sources. While the electricity sector is still one of the biggest global emitters of energy-related greenhouse gases (IEA, 2019a), the share of electricity generation from large-scale RE technologies has grown significantly worldwide. Global RE capacity has increased from only 1.13 TW in 2009 to 2.35 TW in 2018, mainly due to additional capacity in Asia (IRENA, 2019).

Due to differences in their circumstances and priorities, the transition of electricity industries in emerging economies could benefit from a different framing for assessment and comparative analysis of electricity sector sustainability. For example, emerging economies usually have policy goals related to electricity access and may place more emphasis on affordability, while they also typically have lower levels of achieved reliability than developed countries.

A framework with suitable indicators for assessing electricity industry sustainability in emerging economies, and specifically Southeast Asia's (hereafter ASEAN) emerging economies, would be a useful tool for policymakers. This would allow tracking of progress towards sustainability objectives of electricity generation planning, such as security, access, and environmental sustainability (Alanne and Saari, 2006).

Such a framework may encourage countries to take more action towards sustainability, ensure sustainability objectives are included in planning scenarios, and would also enable transparent assessment of progress toward sustainability. The framework could also focus attention on specific operational metrics and therefore provide a platform for objective-setting and ensure resources needed for planning and operation are made available.

The UN's Energy Sector Management Assistance Program (ESMAP), in cooperation with other international agencies, launched the energy progress report website which tracks progress and status of developing countries against 'sustainable development goals 7' (SDG7) on a two-year basis (ESMAP, 2020). The framework is built up from indicators classified in five groups, i.e., access to electricity, access to clean cooking, renewable energy, energy efficiency, and international financial flows. However, this framing is less useful for emerging economies, since it focusses on the SDG7 energy access agenda and emerging economies have broader concerns around energy security, reliability and environmental impacts from power generation and industrial sectors.

Sustainability of electricity industries in emerging economies, have been assessed in several studies, in which the scope and approaches are varied, but mostly use multiple criteria within broad technical, economic, social, and environmental sustainability groups. Evaluation of the Lebanese electricity system in terms of its sustainability can be found in El-Fadel et al. (2010). The study assessed used technical (reliability), environmental, energy, and economic criteria. The sustainability performance of the Brazilian electricity industry has also been evaluated in (Sartori et al., 2017). The study assessed social, economic, and environmental sustainability issues using sets of indicators from the Global Reporting Initiative (GRI) for the energy sector. The World Energy Council (WEC) presented the energy trilemma (ET) framework, which uses broad groupings of energy security, access/equity and environmental sustainability, which are in many ways aligned with the broad groupings of technical, economic and environmental sustainability, but serve to emphasise the key policy challenges and potential trade-offs. The ET framework is designed to measure and compare annual performance of countries' energy sustainability, including the electricity sector (WEC, 2018), but the indicators are not specific to the electricity industry.

Very few studies have assessed the sustainability of electricity industries in the context of ASEAN countries. A cross-country assessment of electricity industry sustainability can be found in (Vithayasrichareon et al., 2012). The study presented an analytical '3A's framework' based on the accessibility, availability, and acceptability of sustainability objectives. The framework highlighted six dimensions, namely affordable price, energy services, short-term reliability of supply, long-term reliability of supply, safety and greenhouse emissions, and applied selected indicators and criteria to assess key sustainability challenges of electricity industries in five newly industrialising ASEAN countries. (Kanchana and Unesaki, 2014) used typical electricity industry-based indicators to reflect energy accessibility and efficiency components, including electricity access, electricity consumption per capita, and electricity intensity, as part of an indicator-based assessment of ASEAN energy security.

Beyond the broad framing, the selection of criteria is important, both for appropriately assessing sustainability, and to facilitate use of available data that can allow tracking over time and comparison across countries. (Shaaban and Scheffran, 2017) discussed the method for selection of sustainable development indicators for Egyptian electricity production and planning assessment. Within a 'sustainable development' (SD) framework comprising of 4 sustainability categories (economic, environmental, social, and technical), the authors selected appropriate indicators both from the existing literature and expert interviews. In (La Rovere et al., 2010), the authors applied selected indicators to a model to obtain priority scores for expansion of alternative energy technologies. Selected indicators have been used in studies assessed energy sustainability or energy security, such as in (Mainali et al., 2014), (Erahman et al., 2016), (Patlitzianas et al., 2008), (Narula and Reddy, 2016), (Martchamadol and Kumar, 2013), and (Doukas et al., 2012). Collections of a large number of energy security indicators can be found in (Ang et al., 2015) and (Sovacool and Mukherjee, 2011).

Many existing studies have been focused on the assessment of sustainable electricity status, progress or generation planning in a single country, and existing frameworks often use country-specific indicators that may not be suitable for cross-country comparison purpose. The use of the technical, social, economic, environmental, and institutional sustainability dimensions may also be limited since it is not clear into which dimension some indicators fall. For example, in (Martchamadol and Kumar, 2013), some indicators that have been classified under the technical dimension according to other studies, such as fuel mix in electricity generation, reliability in electricity networks, reliability operating standards, System Average Interruption Frequency Index/System Average Interruption Duration Index (SAIFI/SAIDI) and technical efficiency/losses in the energy transformation, are grouped under the economic dimension, following a classification applied in (Vera and Langlois, 2007). A number of indicators do not fall neatly into one of these dimensions. For instance, those classified under the economic dimension are expected to explain the economic implications of consuming the electricity across sectoral end users, or affordability, and might intersect with social implications by incorporating accessibility.

Tracking sustainability of electricity industries in ASEAN countries could benefit from a framework that includes appropriate indicators to capture the transition status and progress, on both the demand and supply side. This study, therefore, develops and applies a new framework for sustainability assessment of the electricity industries in five ASEAN countries, i.e., Indonesia, Malaysia, The Philippines, Thailand, and Vietnam (hereafter ASEAN-5), which have similar socio-economic backgrounds and challenges. The proposed framework includes a focus on environmental sustainability on both supply and demand sides of the industry and uses indicators with data available across the countries to provide policymakers and stakeholders with a comprehensive tool for cross-country comparative analysis. This study also develops new and revised indicators that should be tracked.

While the term 'security' is defined in a variety of ways in the field of energy studies, it is commonly used as a measure of the level of 'assurance' the supply-side has in meeting varying demand. Reliability is commonly taken to be a measure of actual outcomes in meeting customer demand over a historical time period. Importantly, a power system can be reliable in terms of meeting demand, whilst not being secure if, for example, this reliability could not be assured if particular plants or network elements were to fail. This thesis strictly considers both delivered reliability in terms of achieved USE, as well as security in its consideration of operating reserves. For forward looking studies modelling decades ahead, these two concepts are not so clearly separated. This study has, therefore, used the term security and reliability interchangeably in some parts of the analysis to simply assess and discuss some sustainability issues in the electricity generation planning area.

The rest of this chapter is structured as follows. Section 5.2 explains the proposed sustainability framework. The set of indicators used in the framework is described in Section 5.3, followed by the application of the framework and indicators in Section 5.4 to analyse the sustainability status and progress of electricity industries in the ASEAN-5 by conducting a cross-country comparative analysis of the time-series data. Finally, conclusions are presented in Section 5.5.

5.2 The proposed framework

5.2.1 The framework structure: why it is useful?

This study develops a new framework that gives attention to sustainability on the supply-side and the demand-side (Figure 5.1), whereas many studies focus only on security and availability of generation, and there tends to be a lack of available data on the demand side. However, the demand-side can improve the sustainability of electricity services in varied ways, including through distributed energy, captive power, demand response and energy efficiency, and wider prosumer participation. The framework identifies electricity consumption efficiency (intensity) as one of important attributes of demand-side sustainability, as a proxy to energy efficiency measures. This framing may also help policymakers to understand more the interactions between factors on both sides. The framework emphasises environmental sustainability and interaction with both supply-demand sides, given the urgency of transitioning to a low emissions electricity sector.

The framework structure is depicted with broader interactions between its core – the supply-side, demand-side, and environmental sustainability areas – and exogenous aspects of economic, social, environment, and resources, which drive the industry's development and, at the same time, are subject to the outcomes of the industry.

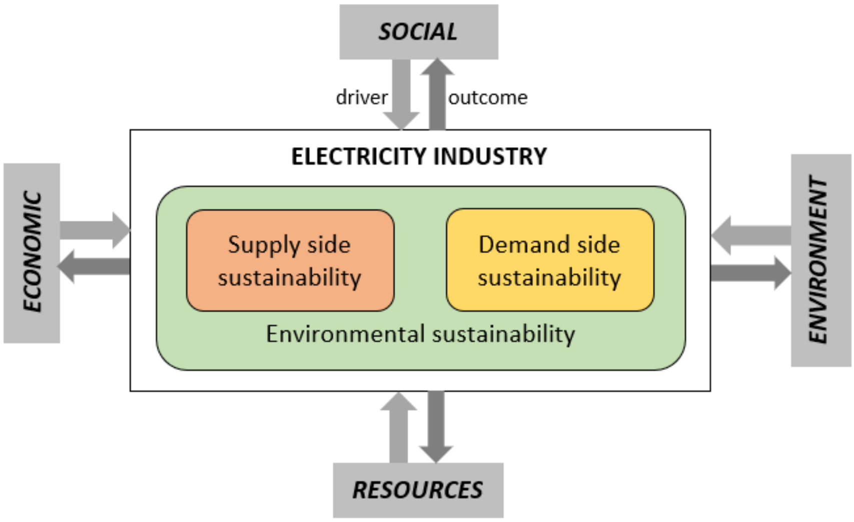


Figure 5.1: The proposed framework for assessing sustainable electricity industries

The supply-side sustainability area relates to both technical and economic dimensions of sustainability and includes indicators for planning and operation purposes, such as reliability, energy security related to the diversity of fuel mix, energy losses, and the cost of electricity generation. Demand-side sustainability relates to the social and economic sustainability of energy utilisation, and includes indicators representing accessibility and affordability, such as electricity price, electricity consumption efficiency (intensity), and demand elasticity. Environmental sustainability spans both supply and demand parts of the framework, since environmental sustainability is affected by both demand and supply sides and their interactions.

5.2.2 Analytical framework for the supply-side sustainability-trilemma

Further analysis can be carried out by focusing attention on one particular part of the framework, for example, the supply-side. Figure 5.2 presents an analytic framework using the supply-side trilemma, in which reliability, cost, and emissions are used as key indicators for technical, economic, and environmental sustainability. This conceptual framework is used for modelling and assessing the sustainability of electricity generation supply scenarios in the following chapters of this thesis.

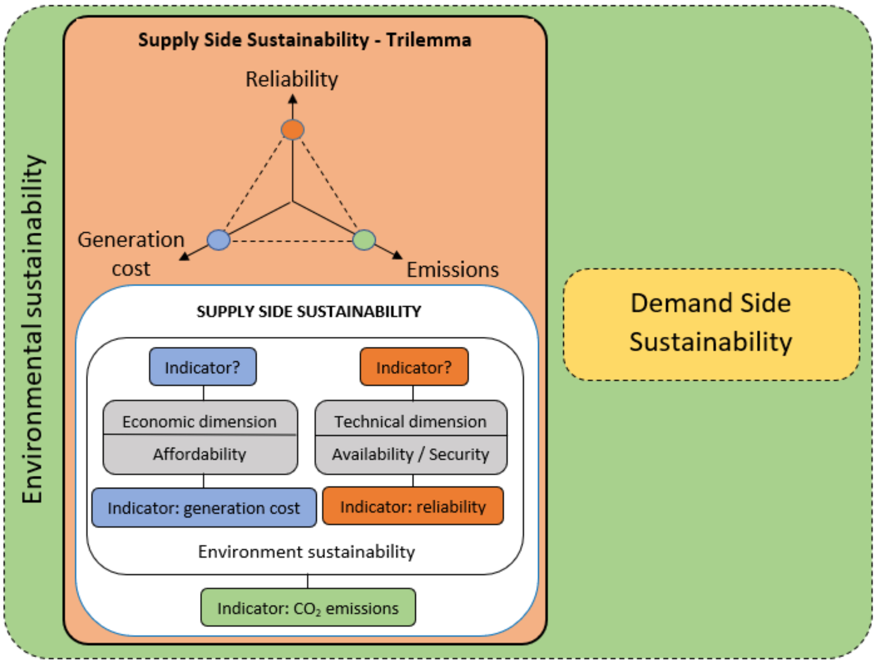


Figure 5.2: A framework focusing on the sustainable supply side-trilemma of electricity industries

5.3 Indicators used in the proposed framework

A set of quantitative indicators for the framework are established, comprising new, revised, and existing ones, based on a review of existing studies and frameworks and indicators. This study applies a selection criteria for indicators, as summarised in (Shaaban and Scheffran, 2017). The criteria are data availability, consistency with objective, independency, measurability, simplicity, sensitivity, and reliability. 'Comparability' is an additional criterion for this framework which is designed to be used for comparative analysis purposes. All indicators are measurable and quantitative, and most are time-series based for tracking progress across time.

Based on these criteria, eight indicators associated with supply-side sustainability, 12 indicators associated with demand-side sustainability, and five other indicators are selected. Table 5.1 presents the complete list of metrics used in the framework and other existing frameworks and indicators used in previous studies.

This study introduces a new indicator called 'Affordability-Index' (AI), and two modified indicators, namely 'electricity net supply factor' and 'electricity supply self-sufficiency'. AI is a partial measure of affordability by quantifying a relationship between electricity expenditure, and income. This metric is defined as the ratio of electricity price multiplied by electricity consumption to income. This metric is needed/useful because existing metrics such as cost of electricity, electricity retail price, and electricity consumption growth rate provide an incomplete progress and status of electricity services affordability. AI of a country can be estimated by multiplying the average electricity price with total electricity consumption and divided by Gross Domestic Product (GDP). This new indicator could also be applied to measure the level of affordability either in a specific sectoral area, for example in the residential sector, provided relevant data is available such as electricity price, electricity consumption and household monthly income. However, care must be taken with interpretation of the results where there is a heavily subsidised electricity price.

The net supply factor, a modification of the capacity factor, is used as one of the indicators for tracking efficiency on the supply-side and electricity consumption per GDP on the demand-side. It is defined as the ratio of electricity available for final consumption to the total capacity of plants in a year. Unlike the term capacity factor, for which the energy output data is measured on the supply side, the net supply factor considers available electricity generation after losses. A higher net supply factor indicates more electricity is available for final consumption since the total installed capacity is more fully utilised, given either unchanged or reduced losses.

Electricity supply self-sufficiency is a modification of energy self-sufficiency focussed only on the electricity sector. As the indicator is focused on the supply-side, it quantifies the ratio of electricity being supplied by the total national capacity to whatever amount supplied by national capacity plus importing electricity from other countries, if any. If domestic supply is larger than the total electricity production in a country, the electricity supply self-sufficiency index is less than 1, indicating that electricity is being imported. On the other hand, an electricity supply self-sufficiency index greater than 1 indicates some electricity is being exported. Energy self-sufficiency, with a broader scope, is obtained by dividing the total primary energy supply of a country by its energy production (IEA, 2020b).

Indicators used in other studies, also listed in Table 5.1, such as strategy for nuclear power, RE share in total final energy consumption, safety, social acceptability, and quality of electricity supply, among others, are not used here because they do not meet one or more selection criteria, not measuring particular aspect or outcome of electricity industry, not consistent with objective, data not available, not quantitative, or difficult to compare among countries.

The sustainability status and progress of ASEAN-5 electricity industries, as measured using all indicators, are elaborated, and compared in Section 5.4.

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
Supply-side sustainability	Fuel types diversification	Shannon-Wiener Index (SWI)	Yes	(IEA, 2020a)			(Availability, Long-term reliability, 13)		(Energy security, Resilience, a)
	Net supply factor	The ratio of actual (final) electricity consumption (GWh after taking out losses) in all sectors to its potential-full time possible output of the total capacity (GW x 8,760hrs)	Yes	(MEMR, 2018), (EVN, 2020), (IEA, 2020d)					
	Electricity supply self-sufficiency	The ratio of GWh electricity produced to GWh domestic supply, in %. Note: If domestic supply is larger than the electricity produced, then import is taking place	Yes	(IEA, 2020d)					
	Energy losses	Transmission and distribution losses, in % of electricity gross production	Yes	(IEA, 2020a)					

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
	SAIDI/SAIFI	SAIDI measures the length of supply interruptions per customer in a year (commonly in minutes); SAIFI measures number of interruptions per customer per year (in frequency)	No	(PLN, 2015), (PLN, 2016), (STEC, 2016), (MERALCO, 2019), (PEA, 2016), (EVN, 2018), (WB, 2019)			(Availability, Short-term reliability, 8)		
	Reserve margin	The realised annual margin of capacity, calculated based on total capacity and system peak demand in a particular year, can be nationally or within a specific grid	No	(PLN, 2015), (PLN, 2016), (PLN, 2017c), (STEC, 2016), (STEC, 2017), (DOE, 2016), (EPPO, 2020), (Satheesh and Thacker, 2014)			(Availability, Short-term reliability, 7)		
	Dependency on imported fuel for electricity generation	Amount of coal and gas imported (in Million tonnes of oil equivalent) compared to coal and gas used for electricity generation	Yes	(IEA, 2020b)			(Availability, Long-term reliability, 12)		
	Unserved energy	The ratio of demand that cannot be supplied during several hours in a period (commonly in a year) to total system demand, in %.	No	(AEMO, 2018)					

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
					Reliability operating standard (checklist)		(Availability, Short-term reliability, 9)		
					Cross border supply and interconnection (checklist)		(Availability, Short-term reliability, 10)		
					Fuel mix in electricity generation (% share of each fuel type)		(Availability, Long-term reliability, 11)		
					Efficiency of energy generation (%)			(Technical, 1)	(Environmental, Energy resource productivity, b, include T&D)
					Resource potential (GWh/year)			(Technical, 2)	
					Reliability of energy supply (%)			(Technical, 3)	
					Water consumption (m^3/MWh or kg/kWh)			(Technical, 4)	

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
					Investment cost (USD/kW)			(Economic, 1)	
					Cost of electricity (USD cent/kWh)			(Economic, 3)	
					Operation and maintenance cost (USD/kW)			(Economic, 4)	
					Energy storage				(Energy security, Resilience, b)
Demand-side sustainability	Total electricity consumption per capita	Electricity final consumption in all sectors divided by population, in MWh per capita	Yes	(WB, 2020a), (IEA, 2020d)			(Accessibility, Energy services, 6)		
	Electricity consumption in the residential sector per capita	Electricity consumption in the residential sector divided by population, in kWh per capita	Yes	(IEA, 2020d), (WB, 2020a)					
	Electricity consumption per GDP	Electricity final consumption divided by GDP, in MWh/million US$ (GDP at the current rate)	Yes	(WB, 2020b), (IEA, 2020d)		(Energy efficiency, 1, in MJ/USD PPP)	(Accessibility, Energy services, 5)		

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
	Residential sector share of electricity consumption	The ratio of GWh (consumption) in residential to total GWh (final consumption), in %	Yes	(IEA, 2020d)					
	Industrial sector share of electricity consumption	The ratio of GWh (consumption) in industrial sector to total GWh (final consumption), in %	Yes	(IEA, 2020d)					
	Electricity consumption elasticity with respect to GDP	The ratio of annual consumption growth to annual GDP growth, in %. Note: GDP growth is calculated using exchange rates (constant), using 2010 billion US$ as baseline	Yes	(IEA, 2020d), (WB, 2018)					
	National electrification rate	Access to electricity, in % of the population	Yes	(WB, 2020c, IEA, 2020d, WB, 2020a)		(Access to electricity, 1)	(Accessibility, Energy services, 4)		(Energy equity, Access, a)
	Rural electrification	Access to electricity in rural, in % of the rural population	Yes	(WB, 2020b)		(Access to electricity, 3)			
	Electricity retail price	Residential electricity price, averaged price during a year or in a specific month, in cent-USD/kWh	No	(Vithayasrichareon et al., 2012), (IEA, 2016), (Epifany, 2018), (Oplas Jr., 2017), (Del Mundo, 2016), (Doshi, 2013)			(Accessibility, Affordability, 1, no specific sector)		(Energy equity, Affordability, a)

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
	Subsidies expenditure on electricity	Amount of government budget spent in the electricity sector, mainly to subsidize the difference between electricity generation and distribution cost and retail price a year, in USD/GWh electricity consumption	No	(MFRI, 2018)			(Accessibility, Affordability, 3, in the checklist)		
	Share of household expenditure for electricity in urban and rural areas	The ratio of per capita average monthly expenditure on electricity to the total per capita average monthly expenditure on housing utility and maintenance in urban/rural areas, in %	No	(SI, 2018)			(Accessibility, Affordability, 2, in % of income, no specific areas		
	Affordability Index	The ratio of electricity retail price multiplies electricity consumption to income	No	See refs. for electricity retail price, electricity consumption, and GDP					
					Urban electrification rate (% of the population)	(Access to electricity, 2)			
					#Population without access to electricity	(Access to electricity, 4-6)			

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
					Clean cooking access rate (%)	(Access to clean cooking, 1)			(Energy equity, Access, b)
					Total population without access to clean cooking fuels and technologies (millions of people)	(Access to clean cooking, 2)			
					Job creation (Jobs/kW or Jobs/MWh)			(Economic, 2)	
					Quality of electricity supply				(Energy equity, Quality of supply, a)
					Quality of supply in urban vs rural areas				(Energy equity, Quality of supply, b)

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
Environmental sustainability	Share of renewables electricity generation	The ratio of electricity produced from RE to total electricity production, in %	Yes	(IEA, 2020a)			(Acceptability, Greenhouse emissions, 16)		
	Per capita renewables electricity generation	Electricity produced by RE divided by population, in MWh per capita	Yes	(IEA, 2020a), (WB, 2020a)					
	CO_2 emissions per capita from electricity generation	CO_2 emissions ($grCO_2$/kWh) from electricity generation multiply by electricity generation divided by population, in tCO_2/capita	Yes	(WB, 2020a), (IEA, 2019a)			(Acceptability, Greenhouse emissions, 17)		(Environmental, CO_2 emissions, b, c)
	CO_2 emissions per GDP from electricity generation	CO_2 emissions from electricity production divided by GDP using the exchange rate (2010 million US$), in tCO_2/million US$	Yes	(IEA, 2019a), (WB, 2019),			(Acceptability, Greenhouse emissions, 18)		(Environmental, CO_2 emissions, a, unspecified sector)
	Regional air pollution from electricity	The measured level of SOx, NOx, PM	No	(ERIA, 2017b), (IEA, 2016)				(Environment, 1-3)	

Sustainability area	Indicators selected in the framework (this study)	Remarks	ASEAN-5 comparable annually time series data	Data ref.	Other indicators	Existing frameworks			
						SDG7 (ESMAP, 2020)	3A's (Vithayasrichareon et al., 2012)	SD (Shaaban and Scheffran, 2017)	ET (WEC, 2018)
					RE share in total final energy consumption (%)	(RE, 1)			
					RE share in total final energy consumption for electricity	(RE, 2)	(Acceptability, Greenhouse emissions, 17)		
					Strategy for nuclear power (checklist)		(Acceptability, Safety, 14)		
					Renewable energy policy (checklist)		(Acceptability, Greenhouse emissions, 15)		
					Safety (Fatalities / accident)			(Social, 1)	
					Social acceptability (ordinal scale)			(Social, 2)	
#In the SDG7 framework, indicator is breakdown to total, urban and rural population.									

Table 5.1: Indicators used in the framework and other existing frameworks and indicators used in previous studies

5.4 Sustainability status and progress of ASEAN-5 electricity industries

This section presents a comparative assessment of sustainability of electricity industries in ASEAN-5 (Indonesia, Malaysia, Thailand, The Philippines, and Vietnam) using available metrics that build up the sustainability framework, as presented in Table 5.1. For benchmarking purposes, this study also includes trends achieved by the Organisation for Economic Cooperation and Development (OECD) countries in some of the indicators.

5.4.1 Supply-side sustainability

5.4.1.1 Fuel types diversification in electricity generation

The Shannon-Wiener Index (SWI) is calculated based on the diversity of fuel types in the generation mix. Fuel types considered in this study are coal, oil (including diesel), gas, hydro, geothermal, solar and wind, and biofuel and waste. A higher SWI, which indicates a more secure electricity industry, sees more fuel types available in the system with more equal shares between them. Figure 5.3 shows trends of SWI in terms of fuel types diversification in electricity generation in ASEAN-5 during 2001-2018 (IEA, 2020a).

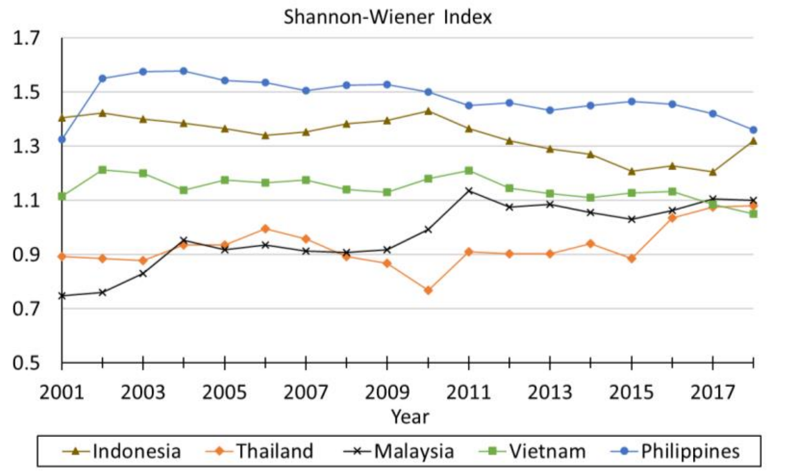


Figure 5.3: SWI trends of fuels type diversification in electricity generation in ASEAN-5

ASEAN-5 has been, in general, highly dependent on coal and gas. The Philippines has achieved the highest and relatively most stable SWI due to the availability of all fuel types, including coal, in the generation mix with more or less equal shares. Indonesia has shown a declining trend until 2017 mainly due to the decreasing contribution of hydro and insignificant contribution of solar and wind, despite an increased geothermal capacity. Malaysia and Thailand have increased their SWI due to greater coal and gas domination and higher penetrations of renewables but without geothermal.

5.4.1.2 *Net supply factor*

Figure 5.4 shows variation of the net supply factor (defined as the ratio of electricity available for final consumption to the total capacity of plants in a year) of electricity generation in ASEAN-5 and OECD countries during 2001-2018 (MEMR, 2018), (IEA, 2020d), (STEC, 2020), (DOE, 2020), (EPPO, 2020), (EVN, 2020). While most countries have shown a fluctuation in their annual net supply factor, the Philippines has generally shown a smoothly increasing trend, opposite to that shown by the OECD countries. If imported electricity is considered in the analysis, all countries have improved in 2018 compared to 2001, except Malaysia with only -3%. Thailand has shown a declining trend due to more electricity being imported during 2011.

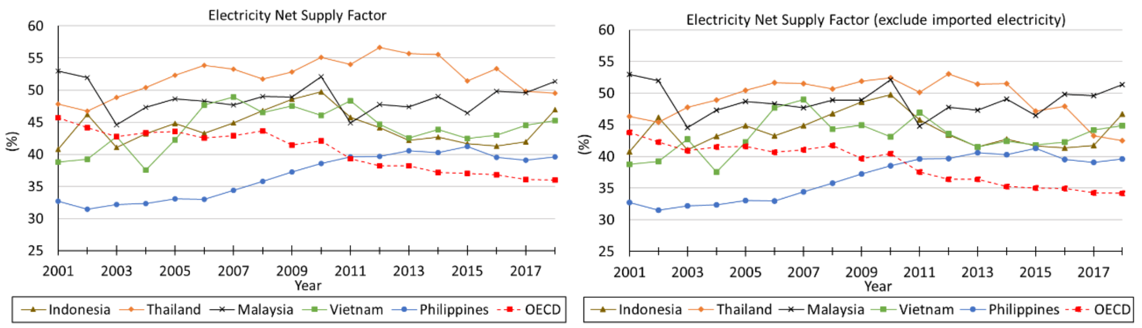


Figure 5.4: Trends of the net supply factors in ASEAN-5 electricity industries and OECD: (left) imported electricity is included, and (right) imported electricity is excluded

5.4.1.3 *Electricity supply self-sufficiency*

Figure 5.5 shows trends in the electricity supply self-sufficiency in ASEAN-5 and OECD (IEA, 2020a). This indicator is stable across all countries except for Thailand, Malaysia, and Vietnam. Malaysia gained a positive index in a few years due to electricity exports, while Thailand and Vietnam were mostly importing electricity.

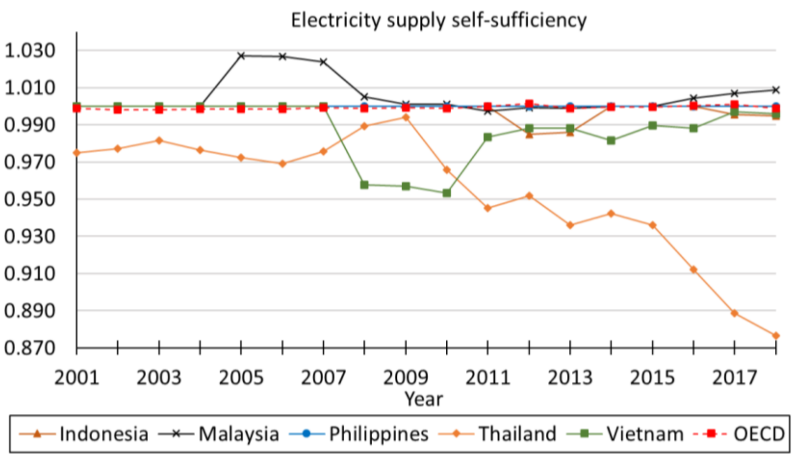


Figure 5.5: Trends in the electricity supply self-sufficiency in ASEAN-5 and OECD

In 2018, Thailand imported electricity to meet about 26 TWh or 12% of the total domestic supply. Although, based on this indicator, the Philippines is an electricity self-sufficient country due to its lack of grid connection with neighbouring countries, the country still imports coal as a major fuel for electricity, mainly from Indonesia. This indicator, however, does not consider the imported fuel required for electricity generation.

As for OECD countries, in aggregate, the trend has shown nearly 1 (100%) electricity supply self-sufficiency during most of the observed years. Electricity produced within the member countries has been the major source of supply with just very insignificant, less than 0.1% electricity has been imported from outside OECD countries. In 2012 and 2017, only very small GWh of electricity have been sent outside the country members, which has resulted in slightly more than 100% self-sufficiency.

5.4.1.4 Losses in electricity gross production

Electricity losses can be divided into technical and non-technical. The technical losses represent economic loss for the country, caused by transmission and distribution losses as well as plants' poor efficiency (Antmann, 2009). As shown in Figure 5.6, ASEAN-5 have successfully reduced losses by 25% to 30% between 2001 and 2018, reducing the gaps with that achieved by OECD. Data is gathered from (IEA, 2020a).

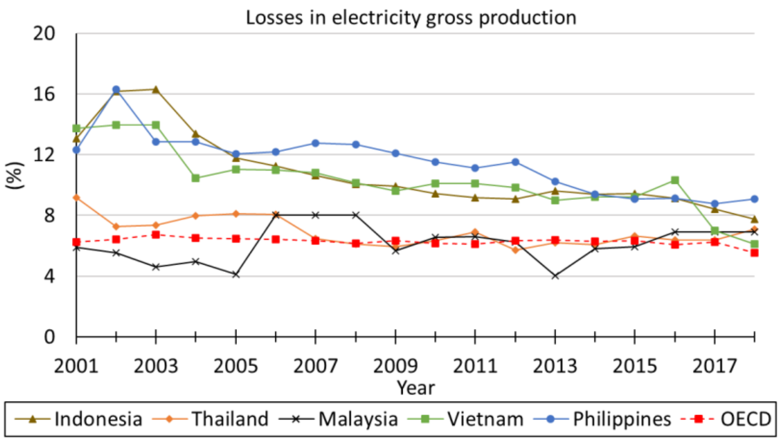


Figure 5.6: Trends of technical losses in electricity gross production in ASEAN-5 and OECD

5.4.1.5 SAIDI/SAIFI

SAIDI/SAIFI are two common indicators used to measure the reliability of supply related to supply interruption on the customers. Table 5.2 presents SAIDI and SAIFI in ASEAN-5 and, for comparison, in Australia's National Electricity Market (NEM) in 2014-2015 (PLN, 2015), (PLN, 2016), (STEC, 2016), (MERALCO, 2019), (PEA, 2016), (EVN, 2018), (AEMO, 2018).

	Indonesia Java-Bali grid		Malaysia Peninsular		Philippines Meralco		Thailand Provincial Electricity Area		Vietnam nationwide		Australia NEM
	2014	2015	2014	2015	2014	2015	2014	2015	2014	2015	Average 2014-2015
SAIDI	348.6	318.6	56.7	51.5	250.3	225.2	217.9	185.5	3.134	2.281	300
SAIFI	5.58	5.97	0.92	0.83	2.66	2.43	6.46	5.84	18.1	13.4	1.5

Table 5.2: SAIDI/SAIFI in ASEAN-5 and Australia NEM in 2014-2015

During 2014-2015, Malaysia (Peninsular) has achieved the greatest reliability, even compared to Australia's NEM. Vietnam, on the other hand, has experienced the most frequent and longest duration interruptions.

5.4.1.6 Reserve margin

Utilities usually have a specified level of reserve capacity by allocating additional capacity on top of the expected peak load over a period. The reserve margin in Indonesia, for example, is planned at 30% (PLN, 2018). The realised reserve margin of the electricity industry in ASEAN-5 in 2014-2016 is presented in Table 5.3 (PLN, 2015), (PLN, 2016), (PLN, 2017c), (STEC, 2016), (STEC, 2017), (DOE, 2016), (EPPO, 2018), (EVN, 2020), calculated based on system peak load and available generation capacity.

Year	Indonesia's Java-Bali grid	Malaysia's Peninsular grid	Philippines' Luzon grid	Thailand's EGAT system	Vietnam's Nationwide grid
2014	29.9	23.9	51.5	28.6	30.5
2015	14.8	23.1	53.1	41.9	30.6
2016	10.6	28.8	53.9	40.3	26.5

Table 5.3: Realised reserve margin of the electricity industry in ASEAN-5 in 2014-2016

5.4.1.7 Dependency on imported fuel for electricity generation

This indicator focuses on coal and gas given their domination in the electricity generation mix in ASEAN-5. Figure 5.7 presents trends of imported coal and coal consumption for coal based-electricity generation plants in ASEAN-5 during 2001 to 2018 (IEA, 2020b).

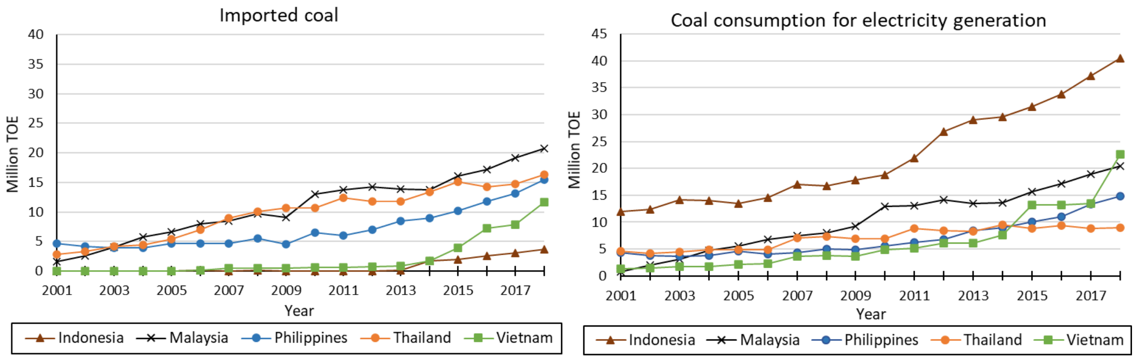


Figure 5.7: (left) Trends of imported coal and (right) coal consumption for coal based-electricity generation plants in ASEAN-5

As one of the largest coal exporters, Indonesia has met most of its own coal demand and imported only a very small amount of high calorific coal for special industrial purposes. Meanwhile, coal-fired power plants in other countries have used either wholly or largely imported coal, as presented in Figure 5.7. Thailand, for example, used around 75% imported coal for its electricity generation. Figure 5.8 shows the trends of imported gas and gas consumption for the electricity industry in ASEAN-5 from 2001 to 2018 (IEA, 2020b).

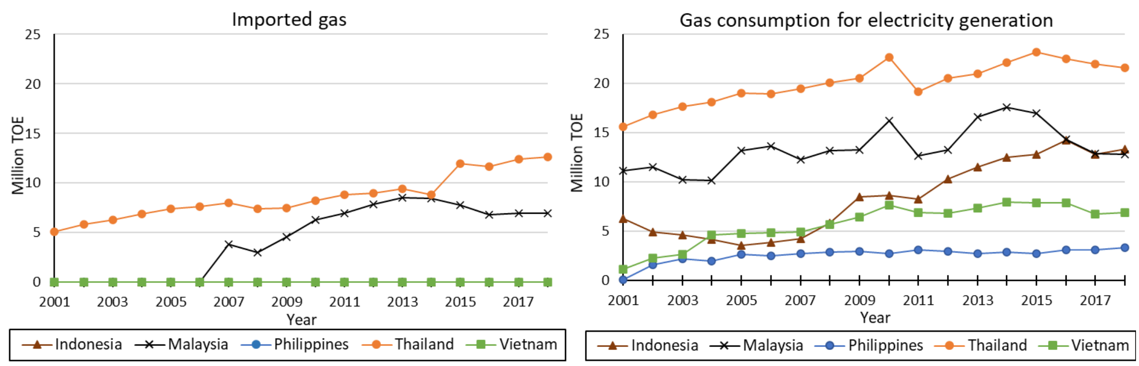


Figure 5.8: (left) Trends of imported gas and (right) gas consumption for gas based-electricity generation plants in ASEAN-5

Indonesia, the Philippines, and Vietnam have met domestic gas demand, including for the electricity industry, through local production. Meanwhile, Malaysia has imported gas since 2007, and allocated around 50% of imported gas to the electricity industry in 2018. Thailand is a similar case, with more than 50% of imported gas allocated to the electricity industry in 2018.

5.4.1.8 Unserved energy

Unserved energy is one of the reliability standards used in Australia's NEM, with a target currently set at 0.002% of the total energy demand in a region for a given financial year (AEMO, 2019). The indicator is defined as the ratio of all unmet demand during a period (typically a year) to the total system demand in that period, expressed as a percentage. Meanwhile, Loss of Load Probability (LOLP) is another reliability indicator used in electricity system planning and operation in some countries, including Indonesia. Despite being widely used, LOLP does not provide information regarding the amount of unserved energy if an outage is expected to occur. Hence, another metric would better capture the risk of unmet demand.

5.4.2 Demand-side sustainability

5.4.2.1 Total electricity consumption per capita

Figure 5.9 shows trends in electricity consumption per capita in ASEAN-5 and OECD countries from 2001 to 2018 (WB, 2020a), (IEA, 2020d). Total electricity consumption per capita in ASEAN-5 has been far below the high, steady trend in OECD countries. Nevertheless, substantial increases have been shown by Malaysia, Thailand, and Vietnam. Meanwhile, Indonesia and the Philippines have consumption below 1 MWh/capita. Improving electricity access has been challenging for both countries given their similar contexts related to power sector development.

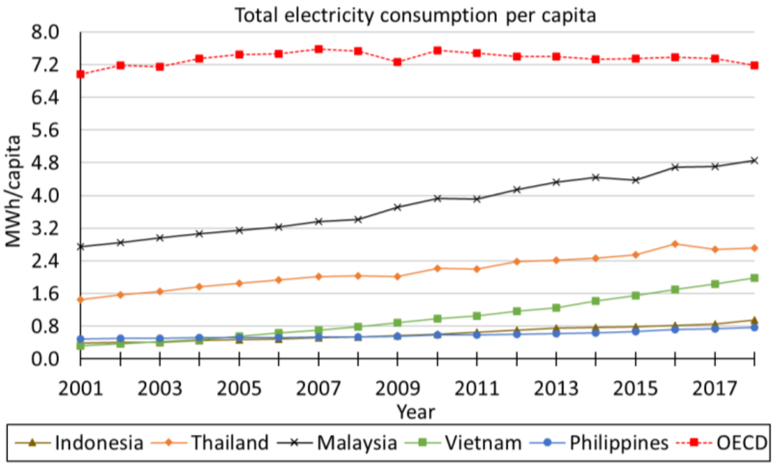


Figure 5.9: Trends in total electricity consumption per capita in ASEAN-5 and OECD

5.4.2.2 Electricity consumption in the residential sector per capita

Figure 5.10 shows total residential sector electricity consumption in the in ASEAN-5 and residential electricity consumption per capita in ASEAN-5 and OECD from 2001 to 2018 (IEA, 2020d), (WB, 2020a).

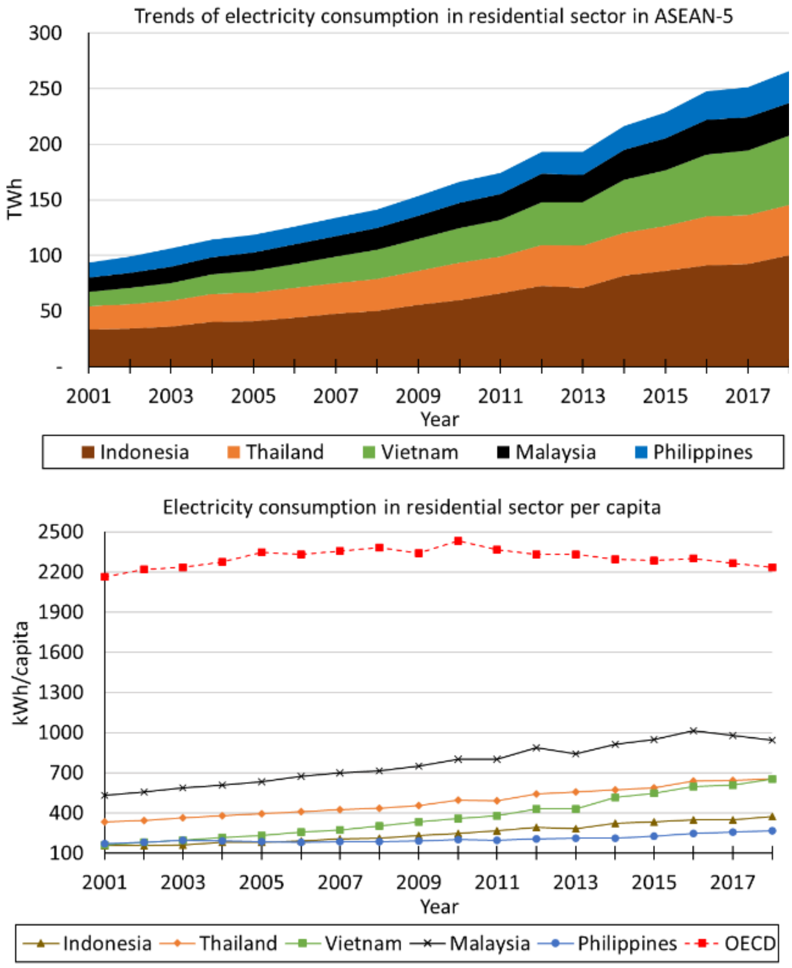


Figure 5.10: (top) Trends of electricity consumption in residential sector in ASEAN-5, and (below) trends in electricity consumption in the residential sector per capita in ASEAN-5 and OECD

Residential consumption in all ASEAN-5 countries has grown. Malaysia has the highest consumption per capita, while Vietnam has achieved the highest growth during the period at around 300%, followed by Indonesia, Thailand, Malaysia, and the Philippines. Nevertheless, these levels of consumption are far below OECD levels. In aggregate, electricity consumption in the residential sector in ASEAN-5 has increased by around 280% in 2018 compared to 2001.

5.4.2.3 Electricity consumption per GDP

In ASEAN-5, electricity is largely used in industrial, residential, commercial, and public services sectors, while little to none has been used for transportation and agriculture. While many developed countries have high electricity consumption and energy efficiency has been widely practiced to increase GDP output, but electicity consumption per unit of GDP (electricity intensity) can also be affected by structural changes away from industry towards a more service-oriented economy. In emerging economies, GDP growth can be rapid, and careful analysis is necessary for interpreting the outcome of this indicator. Where GDP increases at a higher rate than electricity consumption across the period, electricity consumption per GDP decreases, signifying lower electricity intensity in the economy, but not necessarily higher technical efficiency. Figure 5.11 shows electricity consumption per GDP in ASEAN-5 and OECD countries from 2001 to 2018 (IEA, 2020d), (WB, 2018). The trends indicate lower electricity intensity over the period.

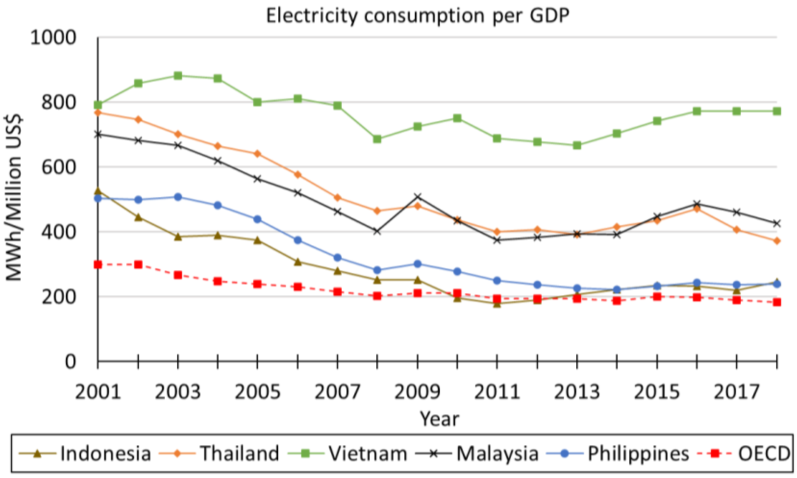


Figure 5.11: Trends in electricity consumption per GDP in ASEAN-5 and OECD

5.4.2.4 Residential sector share of electricity consumption

Figure 5.12 shows trends of the residential sector's share of total electricity consumption in ASEAN-5 and OECD countries from 2001 to 2018 (IEA, 2020d).

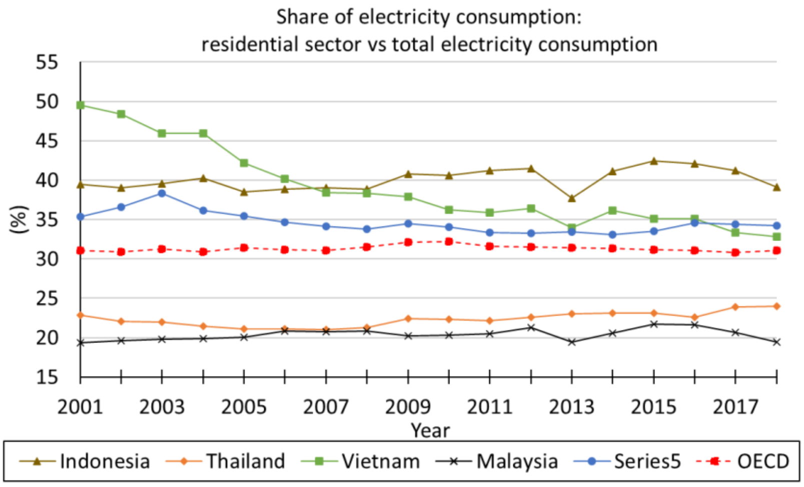


Figure 5.12: Trends in residential sector share of total electricity consumption in ASEAN-5 and OECD

Electricity final consumption in the residential sector has been relatively stable between 2001 and 2018 in ASEAN-5, except Vietnam. Vietnam has been the only country to show a consistently falling share, down 35% in 2018 compared to 2001, as the country's industrial sector electricity consumption was rapidly increasing (see Section 5.4.2.5).

5.4.2.5 Industrial sector share of electricity consumption

Figure 5.13 shows trends in electricity consumption in the industrial sector in ASEAN-5 and trends in the industrial sector's share of total electricity consumption in ASEAN-5 and OECD from 2001 to 2018 (IEA, 2020d). Electricity consumption in the industrial sector has grown almost 200% in 2018 compared to 2001.

Vietnam's industrial sector has shown a significant transformation by achieving a remarkable 960% growth in electricity consumption in this period, while Malaysia, Indonesia, and the Philippines have shown a smaller electricity consumption growth. Understandably, a relatively small average annual growth of electricity consumption in the industrial sector has resulted in a downward trend of the sector's electricity consumption share across these countries.

There are downward trends in Malaysia, Indonesia, and the Philippines across the period. As for Vietnam, the downward trend of the residential sector's share of total electricity consumption (see Figure 5.12) is a result of the greater share of consumption taken by the industrial sector.

Other than the extensive use of electricity, non-electricity energy sources, such as direct combustion of coal, gas and oil, biomass, etc, are also widely utilised in various industries. It is expected that larger share of electricity use in industrial sector in ASEAN-5 in the future will likely include large scale switching from these sources to electricity due to reasons including higher energy efficiency processes and limited opportunities to provide zero-emission solid, liquid and gaseous fuels. Consequently, both supply and demand sides will see additional challenges in satisfying and managing broader electricity loading in industry, and therefore, further measures will be required.

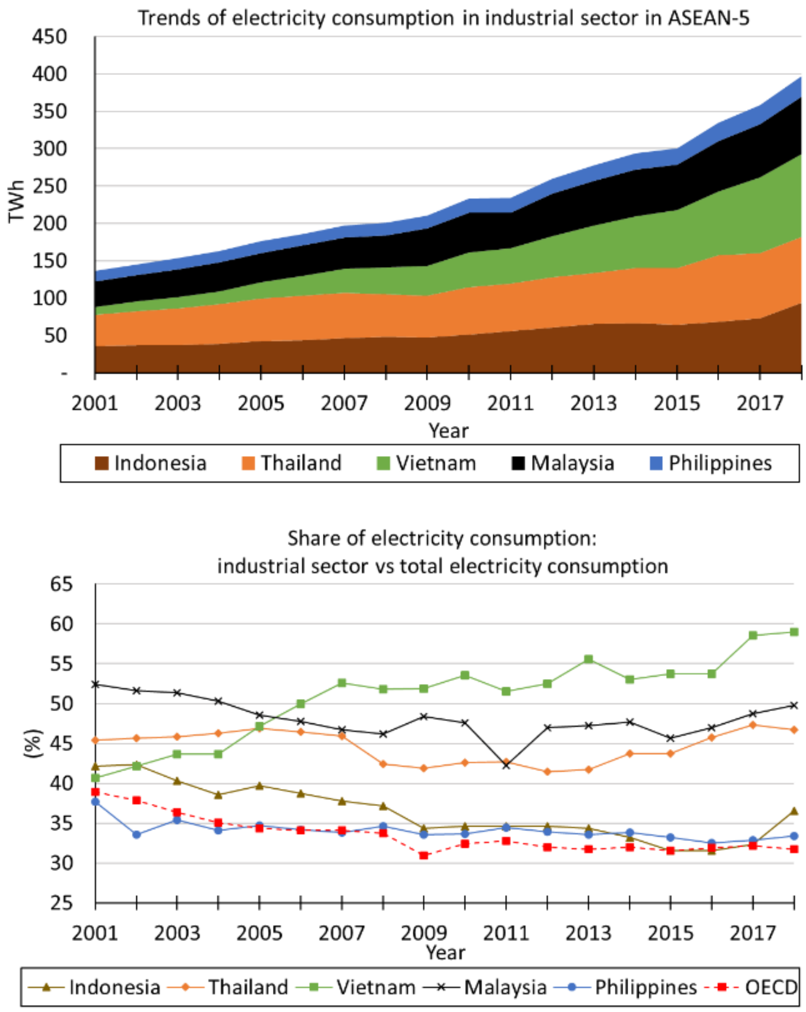


Figure 5.13: (top) Electricity consumption in the industrial sector in ASEAN-5, and (below) the industrial sector's share of total electricity consumption in ASEAN-5 and OECD

5.4.2.6 Electricity consumption elasticity with respect to GDP

Figure 5.14 shows trends in electricity consumption elasticity in ASEAN-5 and OECD between 2001 and 2018 (IEA, 2020d), (WB, 2018).

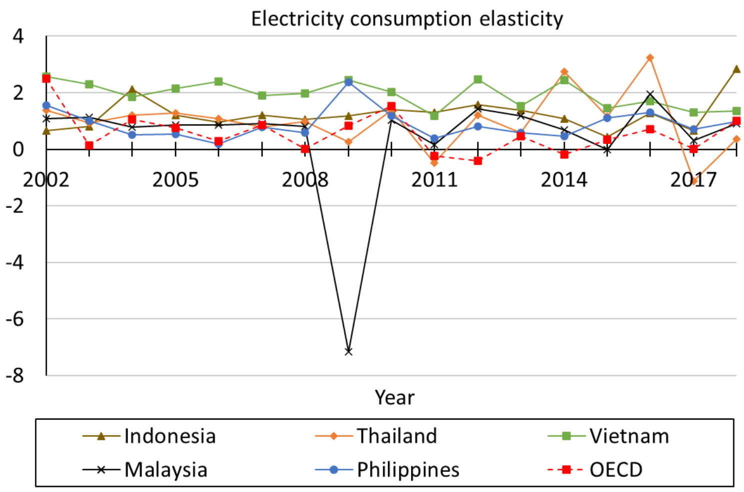


Figure 5.14: Trends in electricity consumption elasticity coefficients in ASEAN-5 and OECD

This study uses electricity consumption elasticity coefficient as one of the indicators to measure electricity consumption efficiency. Defined as the ratio of electricity consumption growth rate to the GDP growth rate (expressed as percentages), a lower elasticity coefficient represents a smaller required change in electricity consumption to achieve a 1% change in the country's GDP.

Note that electricity consumption elasticity should not be used as the only indicator to characterise the relationship between economic growth and electricity efficiency improvement, since a change in electricity consumption can result from improvement in electricity accessibility.

A negative elasticity coefficient can result from growth in electricity consumption but negative economic growth (economic contraction). For example, in 2009, when the global economic crisis affected most Asian countries, Malaysia experienced the lowest elasticity coefficient among ASEAN-5 at -7.2 because the 10.8% growth in electricity consumption did not drive growth in the Malaysian economy, which contracted by 1.5% contraction of GDP over the year.

5.4.2.7 National electrification rate

Figure 5.15 shows the trends of nationwide electricity access in ASEAN-5 from 2001 to 2018 (WB, 2020c). I In recent years, Vietnam, Thailand, and Malaysia reached a 100% electrification rate, as expressed in the percentage of the population that has access to electricity. As shown in Figure 5.15, despite significant improvement Indonesia and the Philippines have struggled to increase reach 100% electrification rate amid similar challenges discussed below, including their dispersed archipelagos.

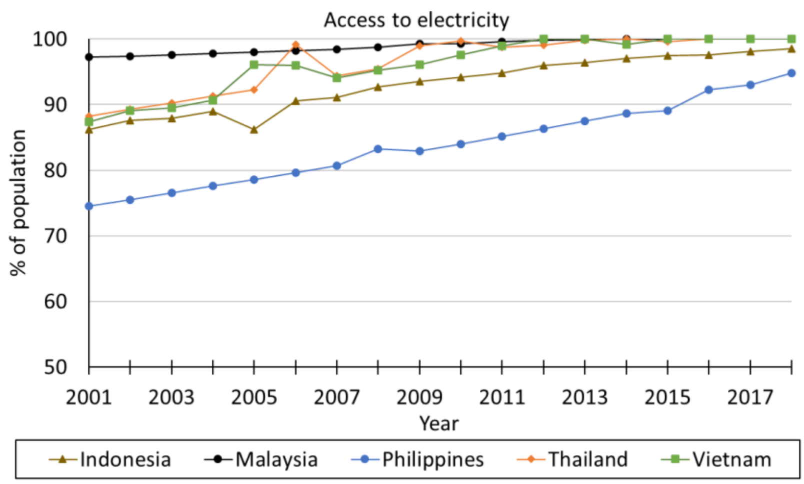


Figure 5.15: Trends of nationwide electricity access in ASEAN-5

5.4.2.8 Rural electrification

Rural electricity access can be measured in terms of the percentage of the rural population that has access to electricity. Indonesia and the Philippines have shown significant progress in rural electrification amid some challenges in extending grid services due to low demand density, difficult terrain, and dispersed setlements. Alternative electricity networks such as mini/microgrids and isolated grids have been constructed to help increase accessibility, mainly involving community-scale RE technologies. Figure 5.16 presents trends of access to electricity in rural areas of ASEAN-5 from 2001 to 2018 (WB, 2020b).

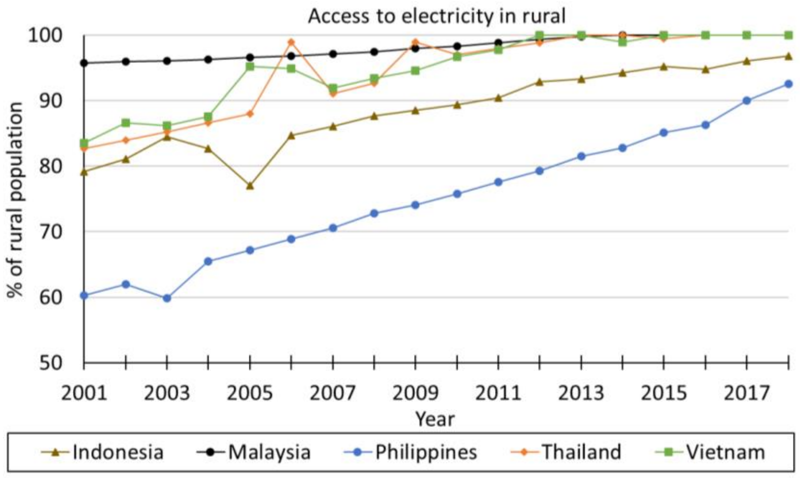


Figure 5.16: Trends of access to electricity in rural in ASEAN-5

5.4.2.9 Electricity retail price

Electricity retail prices in ASEAN-5, except the Philippines, are established and controlled by the government. In this context, to set higher electricity prices is politically unfavorable although such a policy could be seen to be economically reasonable to sustain investment in the electricity industry.

Despite political challenges, subsidy reforms, including gradual reductions in tariff subsidies and adjustments to the eligibility threshold for services, have been successfully implemented in Indonesia, Malaysia, and Thailand (ADB, 2016), helping these countries to improve sustainability of electricity provision. Table 5.4 presents residential electricity prices in ASEAN-5 in selected years/periods from 2005 to 2018.

Year/period	Indonesia	Malaysia	The Philippines	Thailand	Vietnam
July 2018 (Dea, 2018)	11	10	18.67	12.41	10.59
December 2017 (Epifany, 2018)	11	9.34	15.61	12.7	9.67
January 2016 (Oplas Jr., 2017)	7.03	8.83	14.65	9.93	n/a
January 2012 (Oplas Jr., 2017)	8.51	11.11	20.26	10.45	n/a
2011 (Del Mundo, 2016)	14.74	11.46	24.83	9.9	9.2
2008 (Doshi, 2013)	4.59	5.91	12.66	6.9	n/a
2005 (Vithayasrichareon et al., 2012)	2.8	7.1	7.3	5.1	5.2

Table 5.4: Residential electricity price in ASEAN-5 (cent USD/kWh)

Except in Malaysia, residential electricity prices have doubled during this period, while a very low price in Indonesia compared to other countries indicates large subsidies allocated to the sector.

5.4.2.10 Subsidies expenditure on electricity

Electricity reform through a program of phasing out subsidies has been recommended to help the power sector increase efficiency, reduce emissions and improve energy security where the subsidies are on imported fossil fuel use, and encourages increased competition and investment. Nevertheless, it has been a challenge in many emerging economies to implement such reforms due to political tensions, potential for increases in process seen by consumers and other vested interests. Figure 5.17 shows trends in subsidies per GWh of electricity consumption in Indonesia during 2001-2018, along with the total GWh consumption (MFRI, 2018).

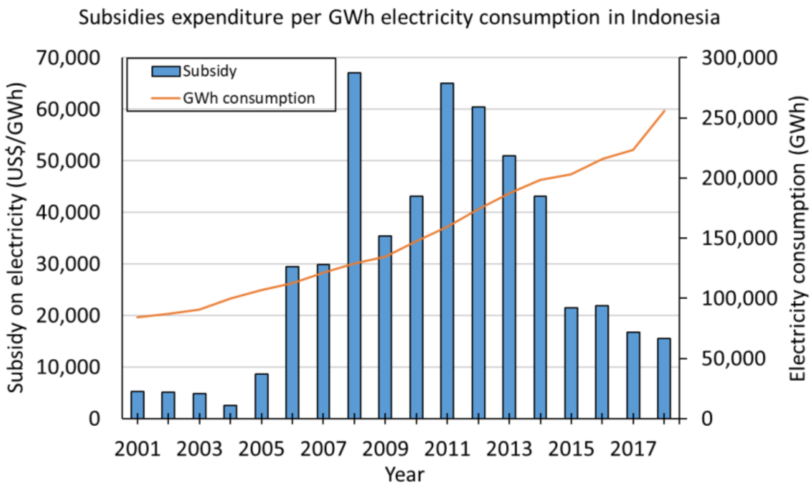


Figure 5.17: Trends in subsidies expenditure per GWh of electricity consumption in Indonesia

High electricity costs relative to electricity tariffs resulted in huge subsidies to generators for several years, partly due to declining currency exchange rates. Starting in 2013, tariffs were then gradually increased as subsidies on electricity and energy were phased out. In 2015, around US$ 4.3 billion was spent to subsidise 202,000 GWh electricity consumption or around US$ 21,400/GWh. This was substantially reduced by more than half compared to 2011-2014.

5.4.2.11 Share of household expenditure for electricity in urban and rural areas

Understanding the proportion of household expenditure spent on electricity can provide policymakers with insights for assessing the affordability aspect of demand-side sustainability, noting that levels of consumption and income also play important roles. This study takes Indonesia as an example. Figure 5.18 presents trends on the share of household expenditure for electricity in urban and rural areas of Indonesia from 2001 to 2018 (SI, 2018).

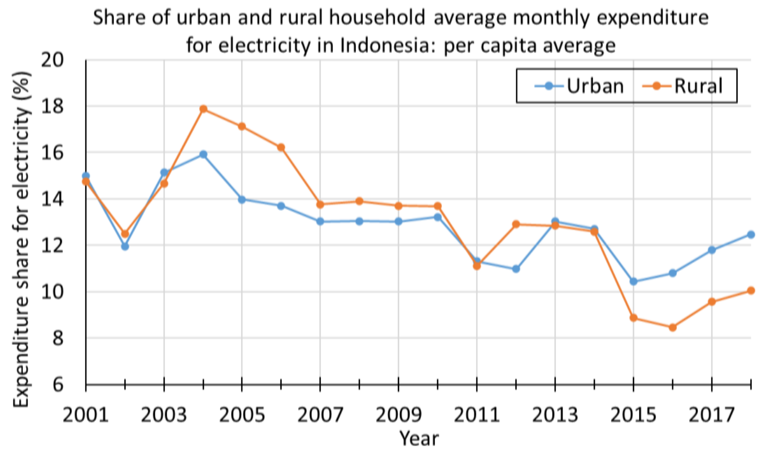


Figure 5.18: Trends of urban and rural household of per capita average monthly expenditure share for electricity of total household's per capita average monthly expenditure on housing facilities and maintenance in Indonesia

The indicator is calculated using available data for per capita average monthly expenditure on electricity, which is part of the total household's per capita average monthly expenditure on housing facilities and maintenance in both rural and urban household in Indonesia. The data are gathered through periodic surveys conducted by Indonesia Statistical Bureau. Over the period, there is a decreasing trend of per capita average expenditure for electricity, both in urban and rural areas, which provides insights regarding the status and progress of affordability.

5.4.2.12 Affordability Index

As described in Section 5.3, Affordability Index (AI) measures affordability by quantifying a relationship between electricity expenditure, and income, and defined as the ratio of electricity price multiplied by electricity consumption to income. Therefore a smaller value could reflect a reduction in price for electricity services or an increase in per-capita income. To illustrate the application of the index, this study calculates the per capita-affordability index of electricity in the residential sector.

This study uses available electricity prices, as presented in Table 5.4, to represent the average electricity price in those years, as well as data on GDP per capita and electricity consumption per capita in the residential sector. The results are presented in Table 5.5.

Year	Indonesia	Malaysia	Philippines	Thailand	Vietnam
2016	0.6	0.8	1.3	1.1	n/a
2012	0.7	1.0	1.8	1.0	n/a
2011	1.2	1.0	2.2	0.9	2.5

Table 5.5: ASEAN-5 per capita-affordability index of the electricity industry in the residential sector

The values of the per-capita affordability index have generally decreased over time in Indonesia, Malaysia, and the Philippines. This could be seen as evidence of progress of electricity industry affordability in these countries from 2011 to 2016, but requires further analysis of electricity affordability to understand from the perspective of consumers.

5.4.3 Environmental Sustainability

5.4.3.1 RE share in electricity generation

RE based electricity generation in ASEAN-5 reached 64 TWh in 2001 and climbed to 220 TWh in 2018. Amid an overall increasing RE share in the generation mix, different trends have been evident in each country, as presented in Figure 5.19 (IEA, 2020a), while OECD has consistently increased the share more than most ASEAN-5 over the period.

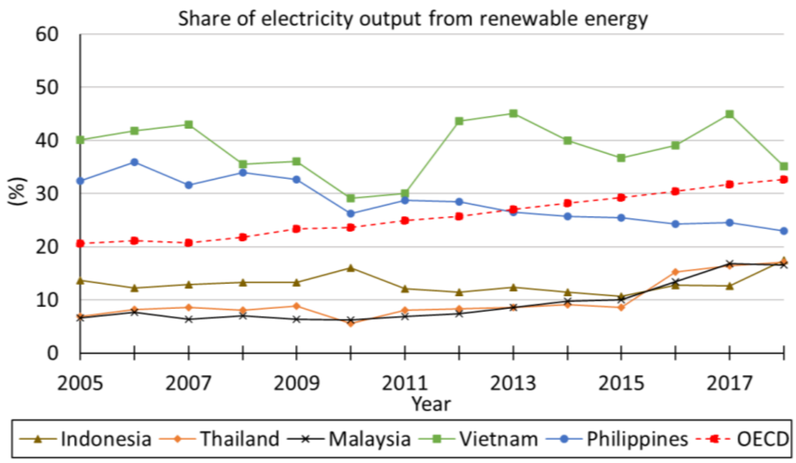


Figure 5.19: Trends of RE generation share in ASEAN-5 and OECD

Thailand and Malaysia achieved higher shares in 2018 compared to 2001, whereas Indonesia has shown relatively slow progress in deploying large scale-RE technologies. The Philippines and Vietnam, on the other hand, show large fluctuations, with an overall declining trend. However, as discussed in Section 2.1.1, Vietnam and Thailand should now see an improved profile on this indicator due to significant addition of wind and solar capacity by 2019.

5.4.3.2 Electricity generation from RE per capita

Figure 5.20 shows the trends of renewables electricity generation per capita in ASEAN-5 and OECD from 2001 to 2018 (IEA, 2020a), (WB, 2020a). Despite low levels compared to OECD, ASEAN-5 has achieved over 100% growth from 2001 to 2018, except for the Philippines where there has been no improvement. Thailand’s achievement indicates transformation of the electricity industry in reducing the domination of fossil fuels, while efforts to increase the RE generation share in Malaysia and Vietnam have delivered significant increases since 2001.

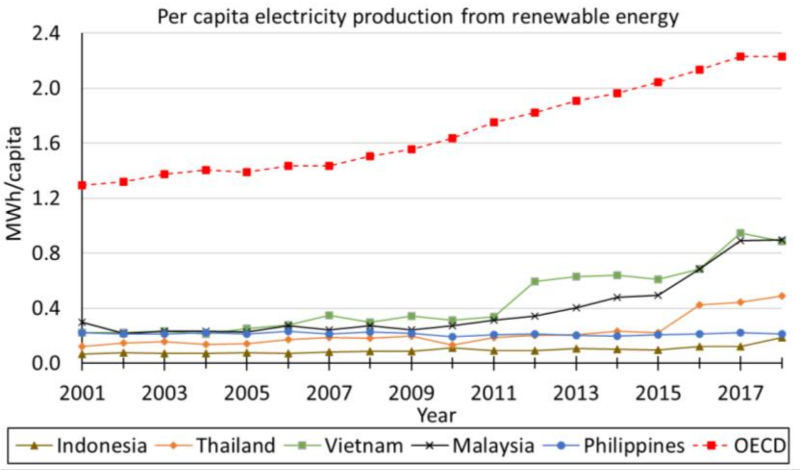


Figure 5.20: Trends of per capita-RE generation in ASEAN-5 and OECD

5.4.3.3 Total CO_2 emissions per capita from electricity generation

Figure 5.21 shows the trends of CO_2 emissions per capita due to electricity generation in ASEAN-5 and OECD (WB, 2020a), (IEA, 2019a). High per capita CO_2 emissions from electricity generation corelate to high electricity demand, supplied largely from fossil fuel generation. However, for OECD countries, the decline in this indicator suggests an increasing RE share of the generation mix.

Vietnam, the Philippines, and Indonesia have experienced a similar trend with emissions remaining below 1.0 tCO_2/capita. This is in part because of the large populations in Indonesia and the Philippines without electricity access and, in Vietnam, is despite a rapid expansion of generation which caused a 400% jump in the CO_2 emissions per capita. While Thailand has shown relatively small increments, Malaysia has recorded a strong upward trend and eventually matched OECD in 2017.

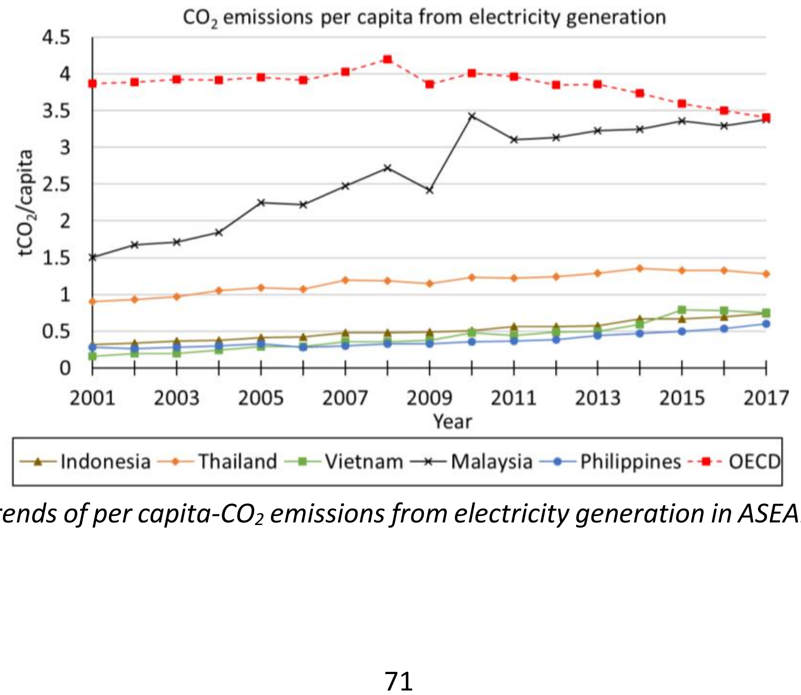


Figure 5.21: Trends of per capita-CO_2 emissions from electricity generation in ASEAN-5 and OECD

5.4.3.4 CO_2 emissions per GDP from electricity generation

Figure 5.22 shows trends of CO_2 emissions per GDP from electricity generation (or electricity emissions intensity) in ASEAN-5 based on current price (top) and on exchange rates, also known as purchasing power parity (below), compared to OECD from 2001 to 2017 (IEA, 2019a), (WB, 2018), (WB, 2019). For each country, the trend is obtained by dividing total annual emissions from electricity production (tCO_2) by either GDP using current price or exchange rate (2010 billion US$) in that year.

Using the first approach, the CO_2 emissions per unit of GDP is seen to decrease, with steeper falling trends for Indonesia and Thailand, indicating improvements in sustainability of the electricity industry. This achievement, however, is unlikely to be due to higher RE output offseting emissions, but rather related to changes in GDP across the period.

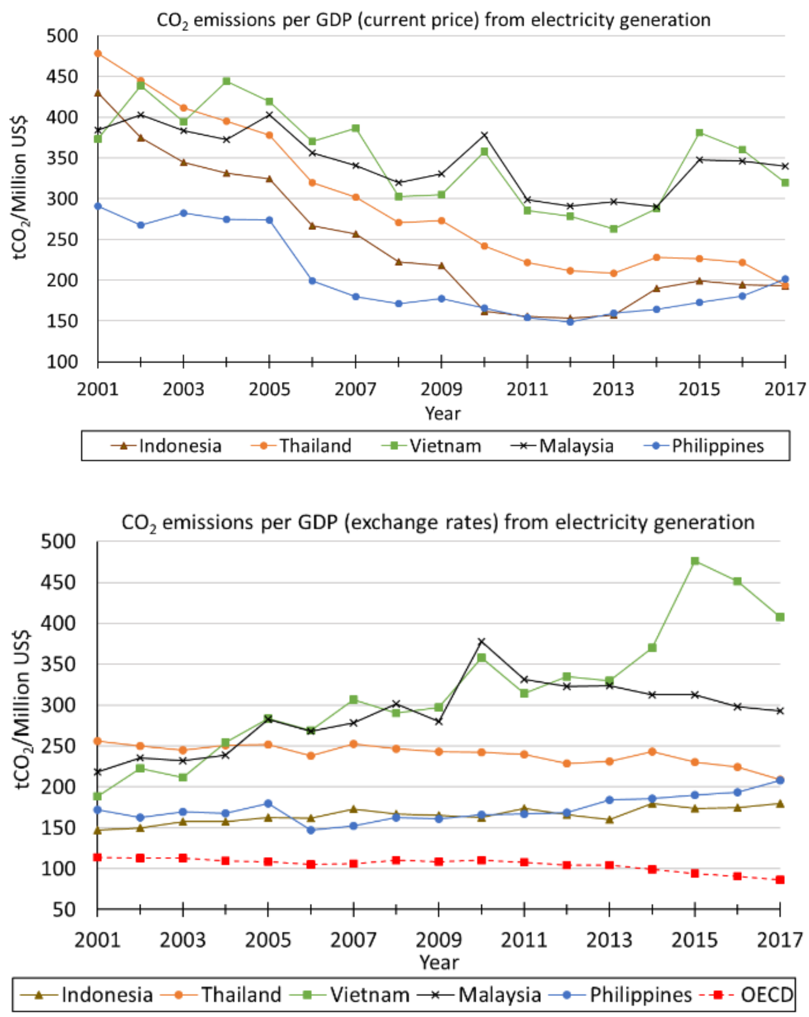


Figure 5.22: (top) Trends of CO_2 emissions per GDP using current price from electricity generation in ASEAN-5 and (below) using exchange rates and its comparison with OECD

Applying the second approach, which is preferable, as seen in Figure 5.22 (top), the trends shown by indicator 'the share of electricity output from RE' presented in Section 5.4.3.1 are confirmed. Thailand was the only country that successfully pushed down electricity emissions intensity over the period, given an increasing share of electricity generation from RE. Indonesia, Philippines, and Vietnam experienced higher emissions intensity due to either unchanged or decreased RE share. Meanwhile, a downtrend for Malaysia after 2010 confirms changes of RE share in the Malaysian electricity generation mix, which reached its lowest point in 2010 and later recovered.

5.4.3.5 Regional air pollution from electricity

Coal-fired power plants are undoubtedly the largest contributors to energy-related SO_2 emissions for the electricity industry in ASEAN-5, with around 2.9 million tonnes, or almost half of these emissions, occurring in Indonesia (Doshi, 2013). Ambient air quality standards are presented in Table 5.6 (IEA, 2016). Air pollution is measured in terms of Sulphur Oxides (SO_X), Nitrogen Oxides (NO_X), and Particulate Matter (PM) or total particulates. Table 5.7 presents the emissions standard (maximum level) related to coal-fired power plants in ASEAN-5 (ERIA, 2017b).

Country	SO_2 (µg/m^3)		NO_2 (µg/m^3)		$PM_{2.5}$ (µg/m^3)	
	24-hour	annual	24-hour	annual	24-hour	annual
Indonesia	365	60	150	100	65	15
Malaysia	105	-	-	-	-	35
Philippines	180	80	150	-	50	25
Thailand	300	100	-	57	50	25
Vietnam	125	50	-	40	50	25

Table 5.6: Ambient air quality standards in ASEAN-5

Country	SO_X		NO_X		PM		Unit
	A	B	A	B	A	B	
Indonesia	750	750	850	750	150	100	mg/Nm^3
Malaysia	500		500		50		mg/m^3
Philippines	1,500	700	1,500	1,000	150	200	mg/m^3
Thailand	360		200		80		ppm (SO_X, NO_X), mg/m^3 (PM)
Vietnam	1500	500	1,000	650	400	200	mg/Nm^3
Notes:							
Indonesia A: in operation before 2008; Indonesia B: in operation since 2008							
Malaysia: > 10 MW capacity							
Thailand (since 15 Jan 2010): power plant size > 50 MW and < 50 MW							
Philippines A (SOx): existing source; Philippines B (SOx): new source							
Philippines A (NOx): existing source; Philippines B (NOx): new source							
Philippines A (PM): urban and industrial area; Philippines B (PM): other area							
Vietnam A (SOx): in operation before 17 Oct 2007 and valid until 31 Dec 2014; Vietnam B (SOx): in operation since 17 Oct 2007 and all plants after 1 Jan 2015							
Vietnam A (NOx): with coal volatile content ≤ 10%; Vietnam B (NOx): with coal volatile content ≥ 10%							
Vietnam A (PM): in operation before 17 Oct 2007 and valid until 31 Dec 2014; Vietnam B (NOx): in operation since 17 Oct 2007 and all plants after 1 Jan 2015							

Table 5.7: Emissions standards relating to coal fired power plant in ASEAN-5

While some air quality standards have complied with international targets, realised emissions have often exceeded the standards. Moreover, prevention, monitoring, and enforcement from local authorities for limiting the realised emissions are lacking.

5.5 Conclusions

ASEAN-5 electricity industries are currently facing complex sustainability challenges in providing improved electricity services, ranging from supply availability to demand affordability, accessibility, and environmental acceptability. This study developed a framework that is useful to assess high-level sustainability of the electricity industry in the context of these countries. In particular, this study explicitly addresses environmental sustainability across both supply-side and demand-side.

One of the major challenges in measuring the sustainability of the electricity industries of developing and emerging economies is the availability of relevant, periodically updated data, with a consistent measurement method. This hinders policymakers and stakeholders from conducting appropriate analysis, identifying problems and potential solutions. Hence for this study, indicators associated with these key dimensions, including new and revised indicators, are selected according to criteria such as data availability, consistency with objective, independency, measurability, simplicity, sensitivity, reliability, and comparability.

By separating but linking supply-side and demand-side, the framework allows their relationships to be captured in the analysis. For example, the uptrend of electricity consumption share in the industrial sector versus the opposite trend in the residential sector in Vietnam, has required the country to supply more electricity from fossil-fuel based generation, as can be seen from the reduced output of RE and increased per-GDP CO_2 emissions from electricity generation.

Detailed assessment across multiple metrics in this framework give a more complete sustainability picture than single indicators. The risks associated with energy security in a country, for example, can increase as the share of imported coal and gas used for electricity generation increases, even if accompanied by insignificant improvement of RE penetrations, such as in the Philippines and Vietnam, despite relatively high scores for fuel type diversification. Similarly, the results of both electricity supply self-sufficiency indicator and dependency on imported fuel for electricity generation should be assessed.

New indicators have been developed to overcome limitations of existing indicators and to provide a better understanding on how the progress of sustainability objectives can be assessed, for example through affordability index (AI). The AI may also provide useful insights, as it can be used to further assess the relationship between electricity retail price, level of consumption, and affordability in different electricity industry sub-sectors.

This study applies the proposed framework, along with the established set of indicators, to assessing the sustainability progress and status of the electricity industries in ASEAN-5 based on time-series data from 2001 to 2017/2018, providing insights into the sustainable transition progress of electricity industries of different countries. Despite ambitious targets in adopting a cleaner generation mix through large-scale RE integration, this study found that most ASEAN-5 countries have exhibited slow progress and towards sustainable electricity industries over the observed period, and by comparison to the OECD. Extraordinary efforts are therefore required to achieve the adopted targets of significant RE contributions to the future generation mix.

Subsequent chapters in this thesis conduct an in-depth exploration focussing on the interaction between the supply-side's key sustainability (trilemma) objectives of secure-affordable-low emissions generation in possible future scenarios. The analyses are conducted through modelling future electricity generation planning with high renewables penetrations to assess possible optimum capacity mixes (see Chapter 7) and further exploring possible clusters of future generation mixes considering future cost uncertainty (see Chapter 8). Finally, this thesis explores extension of the role of high solar and wind penetrations from improving supply reliability – as one of the key objectives – to enhancing system security (see Chapter 9).

Chapter 6
Potential Solar Resources and Impact of High PV Penetrations in Future Generation Electricity Industry Scenarios for Indonesia's Java-Bali grid

This chapter is based on a peer-reviewed conference paper published in the proceedings of Asia-Pacific Solar Research Conference 2017 titled "Photovoltaic deployment experience and technical potential in Indonesia's Java-Madura-Bali electricity grid". The thesis author is first author, responsible for study design, implementation, and primary drafting, with co-authorship also from A/Prof Iain MacGill, Dr. Anna Bruce and Dr. Navid Haghdadi based on supervision, review, and editing.

This chapter primarily assesses the characteristics of solar PV resource across Indonesia's Java-Bali grid and their potential impact on Indonesia's future Java-Bali (including Madura Island) electricity industry scenarios. Possible future least-cost generation mixes are simulated based on a reference scenario as well as other options that consider a range of possible future demand growth rates, future technology costs and gas prices.

6.1 Introduction

The Indonesian government is facing great challenges, yet also opportunities, to improve the nation's future energy mix, particularly in the national power sector, by establishing a target of 23% renewables in its electricity generation mix by 2025 and an increase to 31% by 2050 (MJHR, 2014). Among all commercially available renewable generation technologies solar photovoltaics (PV) seems certain to be crucial in supporting efforts towards these goals, in particular because of the rapid decrease in solar PV system prices in recent years.

Few studies to date, however, have undertaken a detailed assessment of solar PV potential in Indonesia. The energy generation potential and cost-effectiveness of grid-connected PV systems at Indonesia's provincial level has been estimated by (Veldhuis and Reinders, 2013). However, the time interval in terms of PV potential is not clearly specified in the study. Solar radiation analysis has been conducted by (Parangtopo et al., 1984), who analysed global and diffuse solar irradiation (GHI and DNI) in Jakarta, while multi-year solar radiation data for 10 locations in Indonesia and two neighbouring locations in Singapore and Darwin, Australia, has also been analysed (Morrison and Sudjito, 1992). The study found that solar radiation across Indonesia shows a significant east-west gradient. Another study focused on the estimation of global solar radiation in the Indonesian climatic region (Halawa and Sugiyatno, 2001). The study presented monthly average daily global solar radiation correlations applicable to the Indonesian climatic region using a modified version of Sayigh's formula. Mapping of solar irradiation for each province in Indonesia, based on an artificial intelligence technique, has been conducted by (Rumbayan et al., 2012). The study, however, published only a single range of monthly values of solar irradiation for each province using a yearly average National Aeronautics and Space Administration (NASA) database. Mapping of Indonesia's long term monthly average global horizontal irradiation, direct normal irradiation and PV output potential, funded by the World Bank's Energy Sector Management Assistance Program (ESMAP), was recently published by (Solargis, 2017) based on their model.

While these reports provide long term averages that describe the solar resource at different locations in Indonesia and can be used as a preliminary step towards prospecting for PV plant development opportunities, no detailed analyses of temporal and spatial variability were reported in these studies. For power system planning, the variability of the output of PV systems over time and by location, and the correlation of the output of PV in different locations are all important in determining the potential aggregate PV generation availability ramp rates that must be managed by the power system.

Given the limited studies on utilising PV resource mapping for assessing the challenges and opportunities of large-scale PV integration in Indonesia, this chapter first presents a mapping of the temporal and spatial variability of PV generation output in the largest interconnected power grid in Indonesia, the Java-Bali electricity grid. Based on this mapping, sites were selected for a preliminary investigation into possible least-cost future utility-scale PV investment in the Java-Bali grid using the National Electricity Market Optimiser (NEMO) tool (Elliston et al., 2012).

This chapter is organised as follows: the methods are outlined in Section 6.2, followed by the results on Java-Bali solar PV resource mapping and simulation around PV integration in Java-Bali's long-term generation mix in Section 6.3. Finally, conclusions for this chapter are presented in Section 6.4.

6.2 Methods

6.2.1 Java-Bali solar PV resource mapping

Given the significant deployment of utility scale PV expected in the Java-Bali region, it is important to better understand the underlying PV resource available across the region. For this study, one-year of gridded hourly PV power output data across the Java-Bali region was obtained from the online renewable energy simulation tool Renewables Ninja (Pfenninger and Staffell, 2016). The data covers 2015, with a spatial resolution of 0.05° x 0.05° (5 km x 5 km). Renewables Ninja models hourly timestep PV power output at a specific tilt angle based on NASA MERRA2 direct and diffuse irradiation, and ground temperature data, using the Global Solar Energy Estimator (GSEE) model (Pfenninger and Staffell, 2016).

6.2.1.1 Hourly output variability

Integration of high penetrations of VRE such as PV into power systems, combined with underlying variability in demand, increases the challenge of supply demand matching. Changes in PV power output require other generation units to ramp up to maintain the demand and generation balance, requiring sufficient spinning dispatchable generation to be available. This can be challenging at high penetrations, particularly where PV plant output is correlated and large and fast changes in aggregate PV output occur. While managing variability and uncertainty presents challenges over a range of different timeframes, this study evaluates the hourly variability of PV power output. Java-Bali dispatch is planned on a half hourly basis and, of course, PV and demand variability over shorter time frames also poses operational challenges. However, higher frequency data of temporal PV power output for Java-Bali is not available.

The method used in this study for analysing variability is based on (Mills and Wiser, 2010). Change in average power output is calculated as follows:

$$\Delta P_1^{\overline{1hr}}(t) = P_1^{\overline{1hr}}(t) - P_1^{\overline{1hr}}(t-1) \quad (6.1)$$

where $\Delta P_1^{\overline{1hr}}(t)$ is the value of delta power output for 1-hour interval at a single site P_1 for hour t. The standard deviation of the variability (step changes between each hour interval) is defined as:

$$\sigma_{\Delta P_1}^{\overline{1hr}} = \sqrt{Var\left(\Delta P_1^{\overline{1hr}}\right)} \quad (6.2)$$

The 99.7th percentile (three standard deviations, 3σ) value is used as an indicator of the range of variability.

6.2.1.2 Spatial variability

This study also applies spatial variability analysis to assess the level of resource variability between neighbouring locations within a specified distance. The same resource variability may be expected between two different locations with the same colour in a spatial variability map. In practice, this is useful in terms of considering PV plant placement alternatives, and its likely implications for aggregate variability.

This study considers spatial variability of the available 1-year hourly PV output data in 2015, obtained by comparing the 1-year PV energy generation for each 0.05 x 0.05° cell with the surrounding cell. The analysed areas of 25 x 25 km are represented by a 5 x 5 matrix, in which the central cell is located in the centre of the matrix. Following the method proposed by (Gueymard and Wilcox, 2011) the surrounding cell's standard deviations are calculated as:

$$\sigma_s = \left[\sum_{i=1}^{n}\left(E_p - E_i\right)^2/n\right]^{1/2} \tag{6.3}$$

Where E_p is the 1-year PV energy generation (GWh) of the central cell, E_i is the 1-year PV energy generation (GWh) of cell i, which are the surrounding cells, i and n is the number of surrounding cells (in this case 24 cells). The spatial coefficient of variation (COV), C_s, is the ratio between σ_s and E_p.

6.2.2 Simulations, inputs, scenarios, and assumptions

6.2.2.1 Simulation overview

To better understand the potential role of large-scale PV in the future Indonesian generation mix, this section presents a method for conducting preliminary modelling of Java-Bali's long-term generation expansion with large-scale PV integration. It is conducted using National Electricity Market Optimiser, NEMO, an open source, evolutionary algorithm based, techno economic optimisation tool, which was earlier developed and used to study Australia's future electricity using 100% renewable energy (Elliston et al., 2012). Solutions, in terms of generation mix and other parameters, are obtained by evolving lower cost solutions within set constraints. Written in Python[1], the source code can be found in (CEEM, 2018).

Like the majority of capacity expansion models, NEMO is designed to search for the single least-cost generation investment option that satisfies the constraints applied. Among numerous studies, NEMO has been used in this way to model the least cost 100% future renewable electricity system in Australia's National Electricity Market (Elliston et al., 2013), (Elliston et al., 2014), and to compare the cost obtained by these systems with reduced emissions fossil fuel-based systems, including gas and coal with carbon capture and storage (Elliston et al., 2016). NEMO also has been applied in some studies of Indonesia's Java-Bali grid future generation portfolios, such as to explore least-cost high RE portfolios using scenario analyses (Simaremare

[1] Python is an open-source high-level programming language which is interpreted, interactive and object-oriented. It has a large and comprehensive standard library to support the development of a wide range of applications. Python is community driven and has an organization called The Python Software Foundation (PSF).

et al., 2017), and in a clustering-based assessment of cost, security and environmental trade-offs considering possible future generation portfolios (Tanoto et al., 2020).

Evolutionary programming tools generally create a feasible population of solutions, in this case possible mixes of generation technologies and locations, and then simulate their operation over a year or more of dispatch. Reliability criteria may be set either by putting a high price on any unserved energy over the year, or as a constraint for feasible solutions. Similarly, carbon emissions can either be priced ($/t$CO_2$) or set as a constraint for the overall power system over the year. Evolutionary mechanisms are used to evolve this population of feasible solutions towards a least-cost generation mix. Importantly, this evolving mix of generation portfolios can be tracked.

NEMO contains a chronological dispatch model that is used to test portfolios of conventional and renewable electricity generation technologies, and uses an evolutionary programming approach, Distributed Evolutionary Algorithms in Python (DEAP), to search for a near-least cost solution. DEAP is an evolutionary computation framework implemented in Python covering most common evolutionary computation techniques such as genetic algorithms, particle swarm optimisation, and differential evolution (CEEM, 2018). NEMO implements the Covariance Matrix Adaptation Evolution Strategy (CMA-ES), a stochastic method for solving continuous domain optimisation of non-linear non-convex function problems (Auger and Hansen, 2012). Figure 6.1 shows the generic optimisation framework of NEMO, more detailed information including the actual source code is available at (CEEM, 2018).

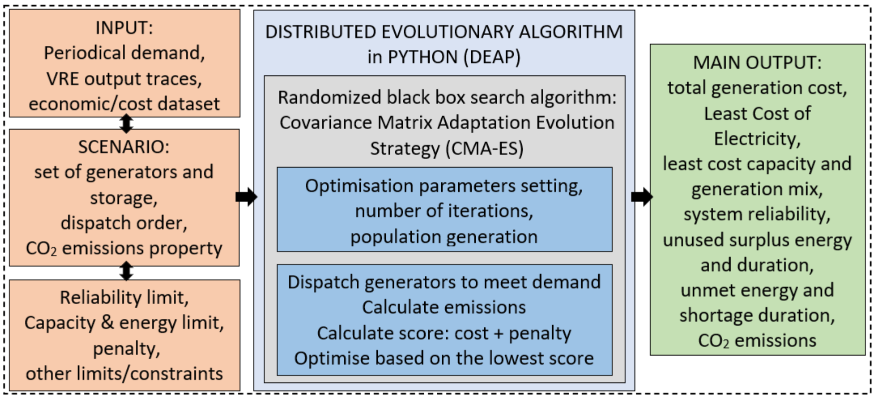


Figure 6.1: The generic optimisation framework in NEMO

The dispatch program in NEMO takes inputs including the projected hourly demand profile over a year, hourly solar and wind generation traces, generation technology constraints, performance, emissions and costs, and potentially system level reliability and emissions costs or constraints. It then creates a family of feasible solutions within these constraints. NEMO then dispatches each possible generation mix in turn, with the objective of minimising operating costs to meet demand for each hour over the year within constraints. It adds capital costs to this annual operating cost, and then tests the solution against any reliability standard or emissions cap. NEMO searches for the least cost generation portfolios using the CMA evolution strategy, for a specified maximum number of iterations. In each generation of the search, several populations are established by the algorithm, and total generation cost (operational and capital) along with penalty (if any), unused surplus energy, achieved unserved energy, and total CO_2 emissions are calculated for each population within each generation. The algorithm then compares the least cost solutions obtained in the current generation with the previous, to find the all-time least cost over the optimisation period. NEMO's two key parameters for evolutionary optimisation, i.e. number of generations and initial standard deviation of the distribution, are set at 100 and 2, respectively, as in (Elliston et al., 2014).

6.2.2.2 Demand data

Located in a tropical climate region with warm and humid weather throughout the year, the Java-Bali region load profile is characterised by only small monthly variations in highest and lowest hourly peak load. The dry season normally occurs around June to November followed by a wet season from December to May. Slightly higher system peak loads are seen around the hottest months in the dry season, i.e., October and November. Annually, minimum loads are mostly associated with the largest religious festival periods in the country and extend approximately a week or two before and after the observed day due to long holidays. This study uses 2015 Java-Bali hourly demand data (PLN, 2017a) as a baseline, as shown in Figure 6.2, and 3.5% to 10% annual growth rates are applied to create a projected 2030 demand profile.

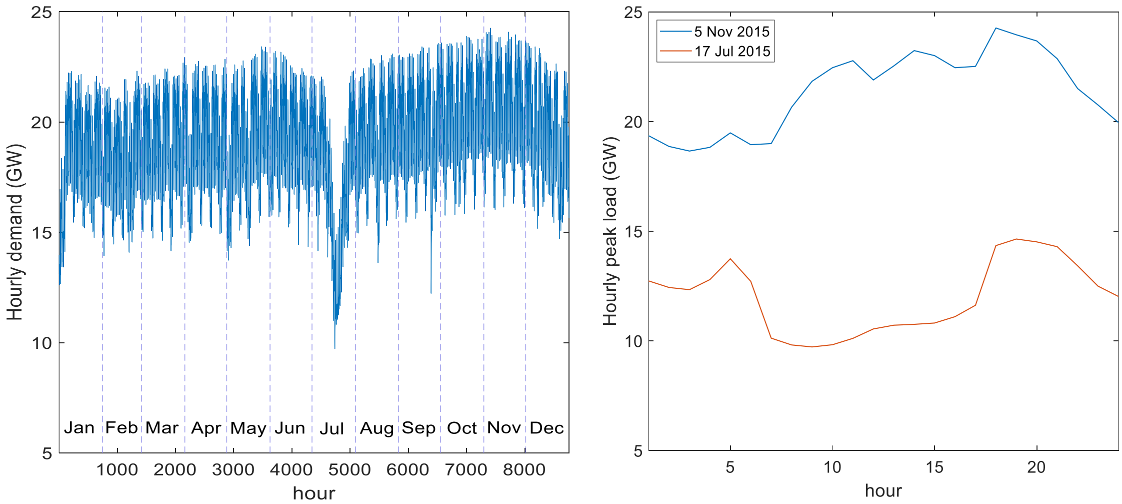


Figure 6.2: The 2015 hourly demand of Java-Bali grid (left) and the corresponding highest and the lowest daily load profile (right)

6.2.2.3 Techno-economic inputs

Coal, gas (open cycle gas turbine and combined cycle gas turbine), hydro, biomass, geothermal and solar PV are modelled as generation mix candidates using NEMO. Build limits (GW) are set for hydro and geothermal in 2030 at 8 GW and 10 GW, respectively, according to (IRENA, 2017b) and (NREEC, 2017, IRENA, 2017b). The model prioritises dispatch of VRE generation technologies with the lowest variable O&M cost, then determines the hourly dispatch order of the synchronous generation candidates according to operating cost: geothermal, followed by hydro, coal, combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), and biomass. All generators in 2030 are costed as new build.

Baseline technology costs for 2015 are taken from an Indonesian government energy council agency report (DEN, 2016) and technology cost scenarios for 2030 are scaled from the baseline by using 2015-2030 cost escalation trends provided by National Renewable Energy Laboratory (NREL, 2017). The international trends are considered to be relevant because most of the technologies are largely imported.

Indonesia's coal and gas price projections for 2030, i.e. \$3.5/GJ and \$10.9/GJ, respectively, are obtained from (IRENA, 2017b). A Loss of Load Probability (LOLP) of 0.274% (equivalent to 24 hours in a year where demand cannot be met by available generation) is used in all scenarios in accordance with the Indonesian reliability standard (PLN, 2017b). In addition, the carbon price and discount rate are set to be \$25/tonne of CO_2 equivalent and 5% in 2030, respectively as suggested in (Elliston et al., 2012).

6.2.2.4 Solar PV generation potential data and placement modelling

Data for 2015 gridded hourly PV power output traces across the Java-Bali region are obtained from Renewables Ninja, as described in Section 6.2.1. Six locations are selected, dispersed across the six provinces in the Java-Bali region, to deploy solar PV. To model this PV generation potential in NEMO, the Java-Bali area is divided into 6 polygons based on provincial classification, and each polygon assigned a PV plant candidate trace, with the PV build limit (GW) uncapped. The provision of traces from each region to the NEMO investment optimisation model provides an equal opportunity for PV to be built in each region. The PV plant candidate in each polygon was chosen according to three factors: high-capacity factor, low hourly temporal variability and low spatial variability. The selected locations are therefore mostly in the southern part of Java-Bali area, where capacity factors are high (Figure 6.2). An additional benefit of these locations is that they are relatively far away from the central part of the islands, which have volcanoes and difficult terrain (highlands).

Other considerations for PV plant locations could include the similarity between each site's output (Elliston et al., 2016). In this case, the coefficient of correlation between polygon 1 (western part of Java-Bali area) and polygons 2-6 are within 0.95 to 0.97, indicating that hourly output is highly correlated across the Java-Bali grid. The highest coefficient of correlation is found between polygons 3 and 4, which is 0.99, making a combination of PV plants at these two locations less complementary in terms of benefiting from generation diversity.

6.2.2.5 Scenarios and assumptions

Several scenarios that consider changes in future technology costs, future gas price and future demand are simulated in order to reveal possible least-cost generation mixes that meet the specified reliability level. This study assumes a reference scenario (LOLP 0.274%, 2030-mid technology cost, 346.5 TWh 2030 demand, 2030 coal price of $ 3.5/GJ and 2030 gas price of $ 10.9/GJ), while the impact of different possible future electricity demand, technology costs, and fuel (gas) prices are also investigated. Therefore, three technology costs scenarios, i.e., 2030 low, mid, and high, are used along with gas prices of $ 7/GJ, $ 10.9/GJ and $ 15/GJ, and four demand levels for 2030, i.e., 279.9 TWh, 346.5 TWh, 493.1 TWh and 696.3 TWh, corresponding to 3.5%, 5%, 7.5% and 10% annual growth from 2015. Average inter-year demand growth rate in Java-Bali grid is measured at around 5% over the past 10 years, with annual load growth varied between those selected demand levels.

6.3 Results and discussions

6.3.1 Java-Bali solar PV capacity factor mapping

Figure 6.3 presents a map of PV capacity factor across the Java-Bali region in 2015, which varies between 16.9% and 18.7%. A relatively high-capacity factor can be seen in Bali (the island at the eastern side of Java) and in the south-eastern part of East Java province.

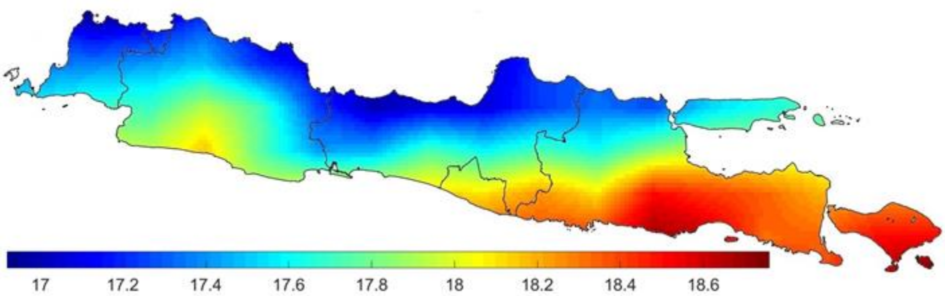


Figure 6.3: Mapping of 1-year PV capacity factor (%) across locations in the Java-Bali region in 2015

Of course, effective, and economically efficient PV integration will depend greatly on the patterns of PV generation across daily and seasonal cycles. The range of monthly PV capacity factors for all Java-Bali locations is presented in Figure 6.4. The three months with the highest monthly capacity factors are September, October, and August, of which the highest median capacity factor was 23.63% (September), while the lowest median capacity factor was 11.87% (April). This significant seasonal variation poses some challenges for PV integration.

Of course, effective, and economically efficient PV integration will depend greatly on the patterns of PV generation across daily and seasonal cycles. The range of monthly PV capacity factors for all Java-Bali locations is presented in Figure 6.4.

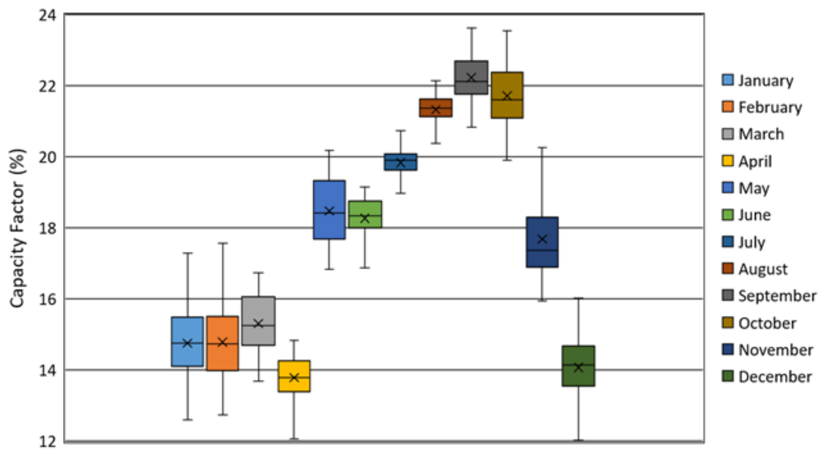


Figure 6.4: Range of monthly PV capacity factor for all Java-Bali locations in 2015

The three months with the highest monthly capacity factors are September, October, and August, of which the highest median capacity factor was 23.63% (September), while the lowest median capacity factor was 11.87% (April).

6.3.2 Hourly output variability

Figure 6.5 shows the range of hourly variability across all locations in the Java-Bali grid expressed as 3σ variability. These fall within a range of 230-254 kW/hr change per 1 MW PV plant capacity. Overall, there is approximately 10% difference between locations with the lowest and highest range of variability, broadly aligned with the 10% difference in capacity factors seen across the Java-Bali region.

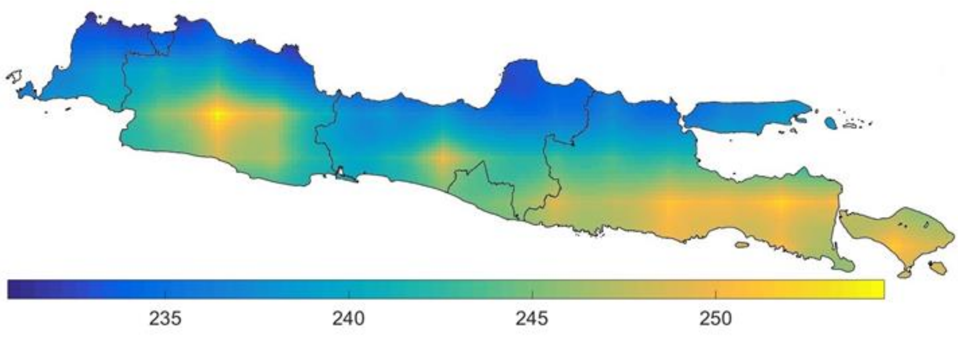


Figure 6.5: Mapping of 2015 hourly ramp rate variability (3σ) across the Java-Bali region

The range of values of 3σ variability across all locations in the Java-Bali grid are shown by month in Figure 6.6. High variability occurred in the same months having high-capacity factor, i.e., September, October, and August. During these three months, the values of 3σ variability were 0.28-0.30 MW/hr per 1 MW plant capacity.

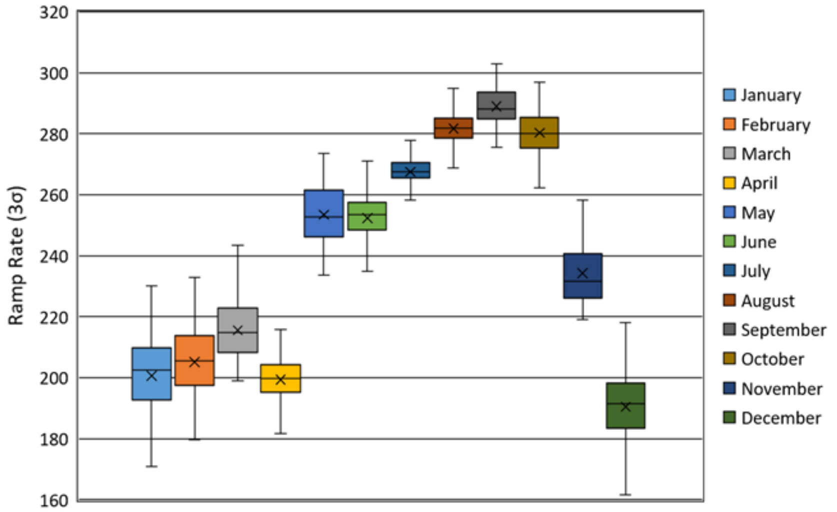
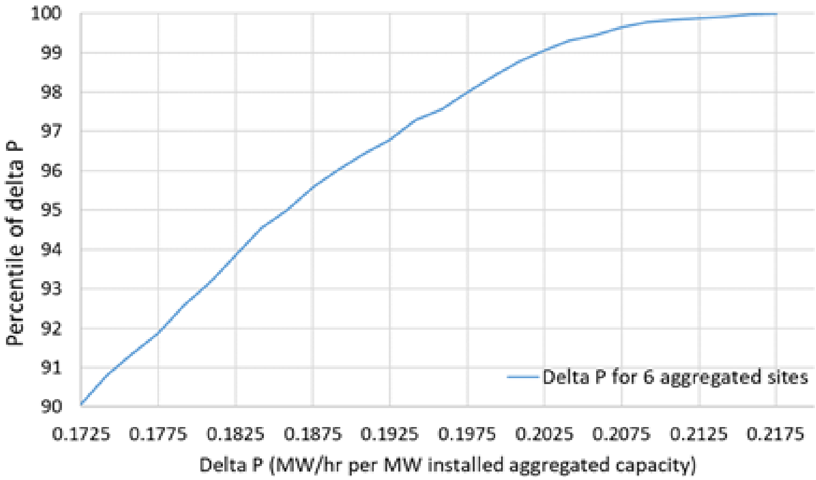


Figure 6.6: Monthly maximum – minimum variability of hourly ramp rate across locations in the Java-Bali grid in 2015, expressed as 3σ

One key question for integration is the effect of PV plant diversity on aggregate output; that is how variability is impacted when PV generation is distributed across multiple, geographically dispersed locations.

To assess this, one location from each province (the small provinces of Jakarta and Banten are merged) was selected, based on sites with the highest capacity factor. Another 19 locations, with more varied capacity factors and ramp rates, were then added to these 6 provincial locations in order to compare the cumulative distribution delta of PV output, as defined in Equation (1).

Figure 6.7 presents the cumulative delta of PV output (in absolute values) for 6 and 25 aggregated locations. The top 10% of the aggregated delta P ranges between 0.17 and 0.22 MW/hr per MW installed aggregated capacity, for both the 6 and 25 aggregated PV locations. In practice, this gives an idea of how much adjustment of hourly output would be required from other generators in order to maintain supply-demand balance in the Java-Bali grid. This would be equivalent to 650-850 MW/hr given a 3.84 GW capacity (equivalent to assuming 60% of the 6.4 GW Indonesian 2025 PV target was deployed in the Java-Bali grid, which supplies around 60% of demand in Indonesia).



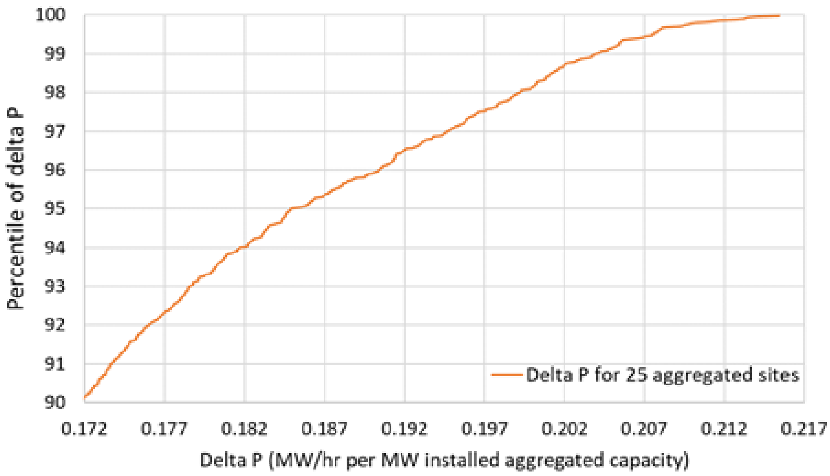


Figure 6.7: Top 10% cumulative distribution of delta P for 6 aggregated sites (top) and 25 aggregated sites (below)

Figure 6.8 presents a comparison of the cumulative distribution of the delta PV output for 1, 6 and 25 aggregated locations. The magnitude of delta P is slightly decreased from 0.24 to 0.22 MW/hr per MW installed capacity from a single site to 6 aggregated locations or more.

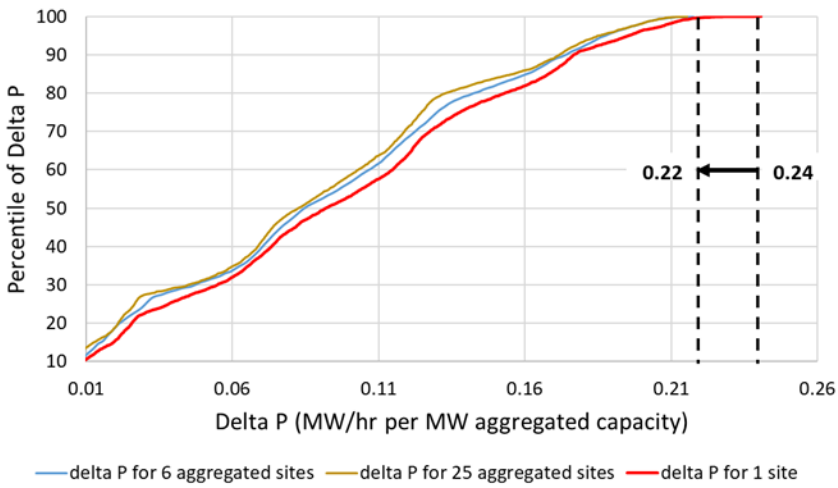


Figure 6.8: Comparison of the cumulative distribution of delta P for 1, 6, and 25 aggregated locations with normalised absolute delta P

6.3.3 Spatial variability

The result of 1-year spatial variability of PV energy generation for Java-Bali region in 2015 is calculated based on Equation (6.3). As mapped in Figure 6.9, the spatial COV (C_s) is expressed as a percentage.

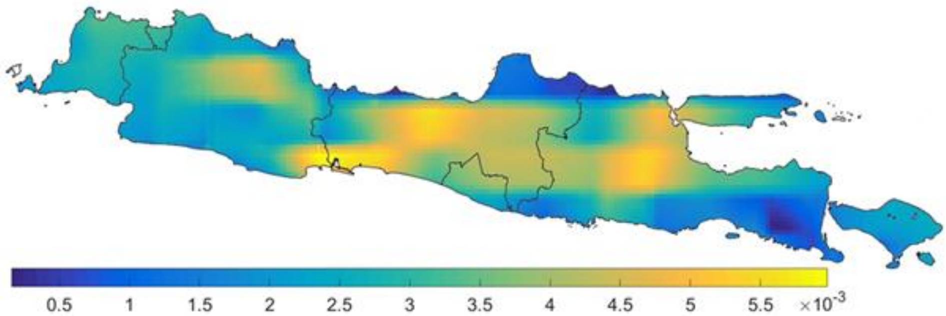


Figure 6.9: The spatial COV (%) of 1-year hourly PV output across Java-Bali in 5x5 matrix

Variation of 1-year PV energy generation can be visually identified on how it varies with distance. The yellow-coloured regions feature higher variability This tends to occur in the highland and mountainous areas, such as those in the central parts of Central Java and East Java provinces, as well as a few coastal areas. Lower variability, on the other hand, tends occurs mostly in coastal and lowland areas, including all areas of Bali. Considering this finding, suitable locations for siting utility-scale PV plants will be around lowland and coastal areas, which have a similarly low range of spatial variation across Java and Bali.

6.3.4 PV integration in Java-Bali's long-term generation mix

This section offers insights into the potential role of large-scale PV in the future Java-Bali power system, through preliminary results of modelling of Java-Bali's least-cost long-term generation expansion options.

6.3.4.1 Reference scenario

Simulation results in terms of system parameters for the reference scenario (USE 0.002%; cost scenario: 2030-mid technology cost; demand: 346.5 TWh; gas price \$10.9/GJ) are presented in Table 6.1, and highlight the least-cost solution has average industry costs of \$50.38/MWh and annual emissions 108.94 $MtCO_2$.

Unused surplus energy (TWh)	0.0
Time steps with unused surplus energy (hr)	15
Min – max shortfalls (MWh)	0.0, 696
Unserved energy (USE) (%)	0.002
Unserved total hours	24
Loss of Load (%)	0.274
Total hour of Loss of Load (hr)	24

Table 6.1: System parameters of the reference scenario

The least-cost capacity and generation mixes for the reference scenario are shown in Table 6.2 and Table 6.3, respectively. Flexible fossil fuel-based generators, i.e., coal fired, CCGT, and OCGT, account for 39.7% and 41.46% of the total capacity and energy generation in 2030, respectively, while geothermal and hydro contribute 25.25% and 20% of the total energy generation, respectively.

Meanwhile, PV's contribution is quite substantial with PV generation built in all regions except Yogyakarta. The total PV capacity and energy generation are 28.91 GW and 46.2 TWh, respectively, accounting for 37.16% and 13.34% of the total capacity and energy generation in the Java-Bali electricity grid.

Under the chosen technology, fuel and carbon costs, these results suggest that PV is already a cost-effective generation option and would be part of an economically least-cost, green fields generation mix for the Java-Bali system. The levelized cost of energy (LCOE) and capacity factors for each generator in the optimisation are shown in Figure 6.10.

Technology	(GW)						%
	Java 1 (Banten + Jakarta)	Java 2 (West Java)	Java 3 (Central Java)	Java 4 (Yogyakarta)	Java 5 (East Java)	Bali 6 (Bali)	
Solar PV	4	9	2.91	0	11	2	37.16
Geothermal	10						12.86
Hydro	8						10.28
Coal	22.3						28.67
CCGT	5.51						7.08
OCGT	3.07						3.95
Total capacity	77.79						100

Table 6.2: Capacity mix of the reference scenario in 2030 Java-Bali electricity grid

Technology	(TWh)						%
	Java 1 (Banten + Jakarta)	Java 2 (West Java)	Java 3 (Central Java)	Java 4 (Yogyakarta)	Java 5 (East Java)	Bali 6 (Bali)	
Solar PV	6.087	14.27	4.651	0	17.95	3.248	13.34
Geothermal	87.49						25.25
Hydro	69.1						19.95
Coal	137.5						39.69
CCGT	5.585						1.61
OCGT	0.5582						0.16
Total generation	346.4						100

Table 6.3: Energy generation mix of the reference scenario in 2030 Java-Bali electricity grid

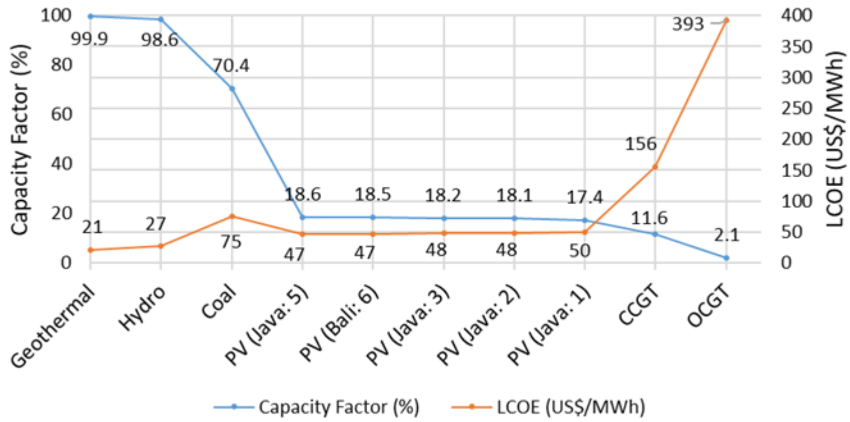


Figure 6.10: LCOE and capacity factor of the generators for the reference scenario

6.3.5 Demand growth and technology cost scenarios

PV capacity could vary between 2 GW and 24 GW for the first demand level and between 4 GW and 35 GW for other demand levels, depending on the gas price. PV capacity would be the lowest for all cases in the high technology cost scenario and highest for the low-cost scenario. Meanwhile, the other generators' aggregated capacity is relatively stable at 40 GW, 50 GW, 70 GW and 98 GW for demand levels of 279.9 TWh (3.5% annual demand growth vs 2015), 346.5 TWh (5% annual demand growth vs 2015), 493.1 TWh (7.5% annual demand growth vs 2015), and 696.3 TWh (10% annual demand growth vs 2015), respectively, given various cost scenarios and gas price.

PV's contribution to the generation mix could range between 5% and 14.4% for the 346.5 TWh energy demand profile. Figure 6.11 shows PV and other generators' aggregated capacity for all demand levels, cost scenarios and gas prices, and Figure 6.12 shows the generation mix for all demand levels, cost scenarios and a gas price of US$ 10.9/GJ.

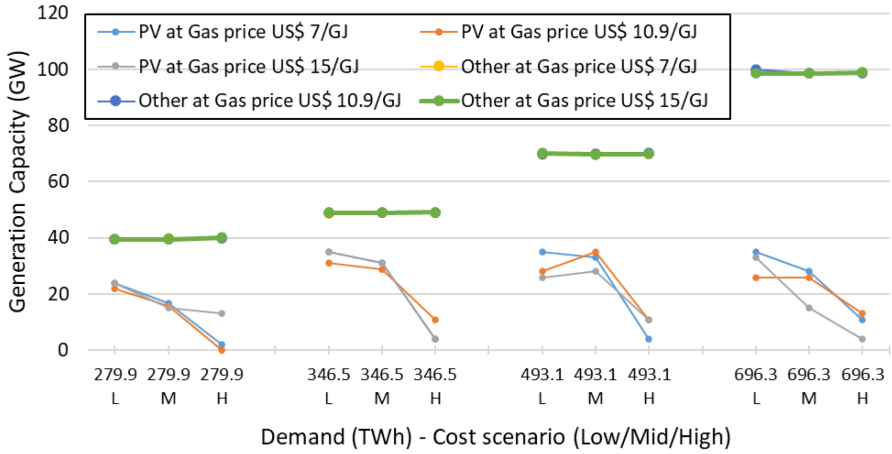


Figure 6.11: PV Capacity (GW) versus other generators' aggregated capacity for all demand, technology costs (L/M/H), and gas prices scenarios (7, 10.9, 15)

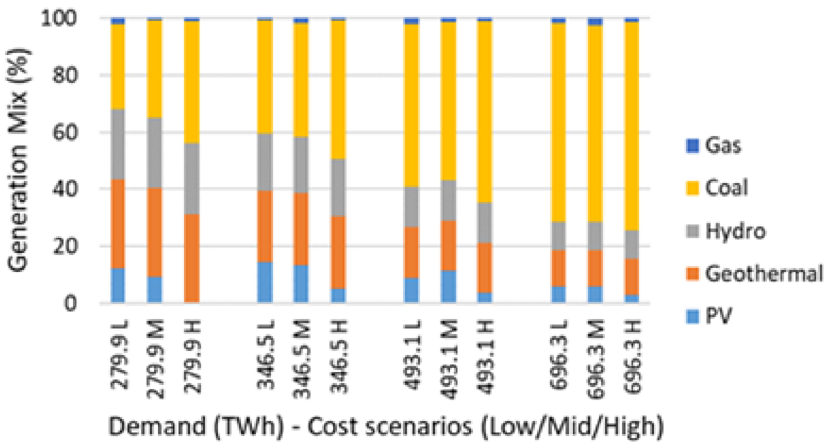


Figure 6.12: Energy generation mix (%) for all demand and cost scenarios at a gas price US$ 10.9/GJ

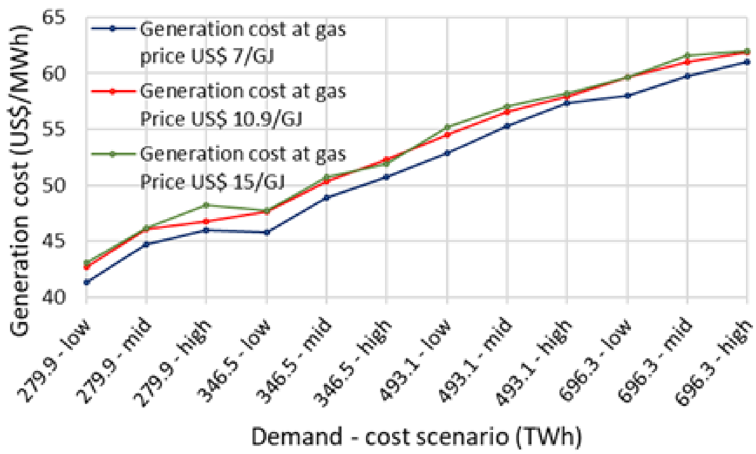


Figure 6.13: Changes in generation costs ($/MWh) for all technology costs, demand, and gas price scenarios

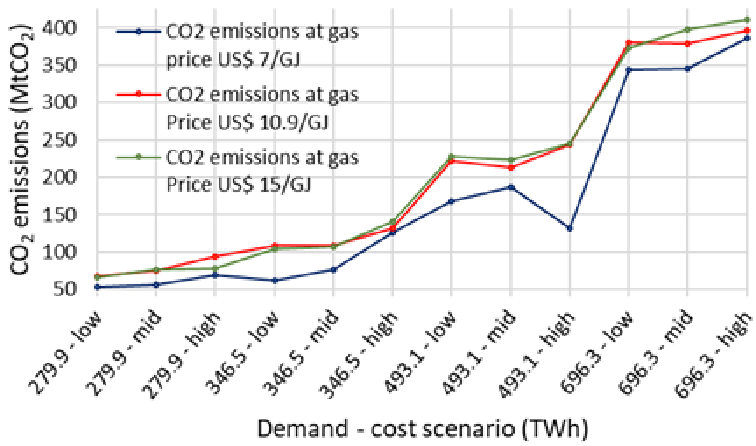


Figure 6.14: Changes in CO_2 emissions ($MtCO_2$) for all technology costs, demand, and gas price scenarios

Figure 6.13 shows changes in average generation costs and CO_2 emissions for all cost and demand scenarios with different gas prices. The average generation cost varies from 41.31-62 ($/MWh) for all costs scenarios. With a 279.9 TWh annual demand, the cost ranges between

41.31- 48.25, while with 696.3 TWh annual demand, costs range from 58-62.02. Meanwhile, CO_2 emissions could be as low as 132 $MtCO_2$ for 493 TWh demand in the high-cost scenario and a gas price of $7/GJ, due to the elimination of coal fired plants in the system, replaced by significant CCGT and modest OCGT generation, as shown in Figure 6.14.

6.3.6 Discussions

The results of simulations conducted for this research suggest that a substantial capacity of PV - that is 25-35% of the total system GW capacity - could be part of a least-cost 2030 generation mix for the Java-Bali grid under a modest carbon price, with only a relatively small variation in PV deployment seen for different gas prices and projected demand, under low and medium technology cost forecasts. In terms of energy generation, PV contributes 8-16% of the total mix under those scenarios. However, for all high technology costs scenarios, PV combined capacity from all regions is found to be very low compared to other generators, i.e., 10 GW or lower, and contributes only around 5% of total energy.

Given the relatively low penetration of PV by energy in all scenarios, it does not appear likely that there would be significant integration challenges. In terms of hourly dispatch, it seems likely that much higher penetrations of PV could be reliably accommodated in the Java-Bali system. While greater supply-side flexibility and ramping capacities may be required to accommodate hourly variability of PV penetration in low and medium costs scenarios, significant geothermal and hydro can provide relatively constant energy generation and load following, respectively, while flexibility can also be provided by gas plants and more frequent ramping by coal fired plants. Shorter term flexibility may present challenges, but there are a range of technology options with decreasing costs, notably battery energy storage systems, that can provide the fast response required.

Although PV integration into the Java-Bali grid of the scale found in the modelling appears both technically and economically feasible, long-term electricity industry planning with PV integration in the Indonesian context requires careful consideration and supportive regulation. Key existing challenges include a lack of transparent planning and publicly accessible information regarding costs, technical characteristics, constraints, performance of existing generators and high quality (measured) renewable energy resource data.

6.4 Conclusion

This study reviews the current status of, and explores the potential for, utility-scale PV deployment in the Java-Bali areas. Recent experiences regarding PV deployment, policies, and regulations relevant to deployment of large-scale PV are described and several key challenges for PV deployment are identified. Mapping and analysis of PV output potential and hourly temporal variability for Java-Bali areas are presented using data obtained from Renewables Ninja based on the NASA MERRA-2 satellite database and the GSEE model. This study also presents preliminary simulations to explore the potential for PV to contribute to an economically efficient generation mix in 2030. PV capacity could vary between 2 GW to 24 GW for the lower demand growth scenario and between 4 GW to 35 GW for other demand scenarios, dependent also on future gas prices. Average generation cost estimates varied from 41.31-62 ($/MWh) for all technology, cost and gas price scenarios.

Meanwhile, another operational challenge might be faced by PLN following the ministerial regulation (MEMR, 2017), which places an obligation on PLN to purchase 100% of the energy generated by PV plants managed by Independent Power Producers (IPPs). This adds to the potential disadvantages to renewable energy deployment for PLN. To improve the situation, in-depth studies regarding feed-in tariff determination would be beneficial, as well as a framework to support efficiency improvements and even encourage competition among energy producers, given the potential benefits of increasing PV integration in the java-Bali power system.

Exploration of the status and sustainability of long-term electricity planning and power sector development in Indonesia would be of great value for policy makers. Such analysis could include consideration of broader aspects of energy security, future uncertainties, and analysis with high penetrations of renewables and more detailed technical constraints. This thesis presents studies on these broad topics in Chapter 5 (a framework and assessment of status and progress towards sustainable electricity industries), and subsequently in Chapter 7-9 (modelling long-term electricity generation planning for Indonesia’s Java-Bali grid).

Chapter 7
Reliability-Cost Trade-offs for Electricity Industry Planning with High Variable Renewable Penetrations

This chapter is based on a paper published in Energy (Elsevier) titled "Reliability-cost trade-offs for electricity industry planning with high variable renewable energy penetrations in emerging economies: A case study of Indonesia's Java-Bali grid". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship by Dr. Navid Haghdadi, Dr. Anna Bruce and A/Prof. Iain MacGill based on supervision, review, and editing.

This chapter presents possible optimum generation portfolios with high variable renewable energy (VRE) penetrations under cost/reliability trade-offs, through exploring the implications of different reliability standards, including relatively high unserved energy, on industry costs for future electricity generation mixes with high VRE scenarios in the context of emerging economies. The study compares two modelling approaches for this - enforcing a given annual reliability target as a constraint and applying a penalty price on all unserved energy - and also considers the utilisation of carbon pricing to drive higher VRE penetrations, with a particular focus on how industry costs should be assessed when such 'shadow' externality pricing and hence 'revenue' flows are utilised.

7.1 Introduction

Electricity industries in many emerging economies[2] achieve only relatively low security and reliability of supply for reasons including rapid demand growth, yet financial constraints, that result in insufficient generation and network capacity. Many of these countries also currently have a high reliance on fossil fuel generation and, certainly across much of Southeast Asia, especially coal (IEA, 2017b). While the technical maturity, dispatchability and highly competitive costs of fossil fuel options has been a key factor in their dominant role, their adverse environmental impacts have, understandably, been a second order concern.

[2] This study uses the term emerging economies rather than developing countries to better acknowledge many countries' general socio-economic development progress, including income and energy access, and transition efforts towards more sustainable electricity industries. Certainly, Indonesia, as a case study, is likely better characterised as an emerging economy rather than a developing one. However, it still experiences far lower grid reliability than industrialised countries typically do, a characteristic shared by many other emerging as well as developing economies.

Over the past decade, extraordinary technical progress, and cost reductions for several renewable energy (RE) technologies, notably wind and solar photovoltaics (PV), have been playing a growing role in many electricity industries, mostly in more developed jurisdictions, supported by a range of renewable policy support mechanisms. Now, however, they are increasingly seen as cost-competitive in their own right (IEA, 2020c). Despite this, many emerging economies, including some in Southeast Asia, continue to focus on fossil generation development pathways for their electricity sectors (Clark et al., 2020).

While solar PV and wind now present a key opportunity, not just for environmental sustainability, but also for reducing industry costs and improving reliability by ensuring resource adequacy, they are, nevertheless, both highly variable and only somewhat predictable, with no inherent energy storage (IRENA, 2017b, IRENA, 2017c), and hence add to the challenges of maintaining security of supply (IRENA, 2017c).

This chapter aims to address the question of how electricity planning for these jurisdictions might better capture the potential generation cost reductions as well as improved environmental outcomes offered by variable renewable energy (VRE), while managing their challenges for system security and reliability. Electricity industry planners have always faced a trade-off between their objectives of reducing total industry generation costs yet also delivering secure and reliable supply. Wind and solar offer low cost but highly variable and somewhat unpredictable generation, adding to the complexity of this trade-off. More generally, there is the question of what the right level of reliability is to seek to deliver. This chapter particularly highlights the question of how emerging economies can be more thoughtful about how they set reliability targets when undertaking future electricity generation planning scenarios with high renewables, and what the implications of lower reliability targets are for costs and environmental outcomes.

As presented earlier in Chapter 3, a large and growing number of studies has explored long-term electricity generation planning with considerably high VRE scenarios. In emerging economies, however, these studies generally seek to obtain the ‘least cost’ future generation technology mix, within security and reliability constraints and perhaps environmental constraints or policy mechanisms. Various optimisation methods and tools have been used for the cases of emerging economies’ electricity industries. Examples on the utilised tools include the Integrated Market Allocation-Energy flow optimization model System (TIMES) (Mondal et al., 2018), (Das et al., 2018); EnergyPLAN (Dranka and Ferreira, 2018), (Pupo-Roncallo et al., 2019), (Bamisile et al., 2020); Long range Energy Alternatives Planning (LEAP) (Kachoee et al., 2018), (Mirjat et al., 2018), (Kumar and Madlener, 2016); the Open Source energy MOdelling SYStem (OSeMOSYS) (Dhakouani et al., 2017), (Rady et al., 2018).

(Rego et al., 2020) proposed a linear programming-based multiperiod optimisation model to assess the impacts of different simulated scenarios, focusing on the demand growth and CO_2 target emissions and considering supply-demand seasonality and the peak period of demand on the Brazilian electricity industry by 2033. (Afful-Dadzie et al., 2020) developed a stochastic mixed integer linear programming-based model to solve electricity generation planning with and without RE targets for Ghana in 2030. The study analysed and compared scenarios around capacity additions, electricity demand met with RE, level of unmet demand, and electricity supply costs. The same method was then applied in (Afful-Dadzie et al., 2020) which focused on the setting and evaluation of 10% RE generation target policies and discussed their impacts on unmet demand and supply cost in Ghana by 2030.

These studies have certainly provided useful insights for policy makers regarding possible future electricity sector generation under different technology and cost assumptions and policy interventions. Less explored, however, has been the implications of different reliability targets of different options and, in particular, the potential trade-offs between reliability and costs.

There is, of course, work exploring reliability-cost trade-offs in the electricity generation planning and operation context. (Ghorbani et al., 2018) optimised hybrid system scenarios using two algorithms: Genetic Algorithm-Particle Swarm Optimisation (GA-PSO) and Multi-Objective Particle Swarm Optimisation (MOPSO). While the authors aimed to obtain a hybrid system with the lowest cost and the highest reliability by conducting reliability/cost assessment and considering several operation reliability indices, the study was carried out in the off-grid context. (Saboori et al., 2015) applied a mixed-integer nonlinear programming with PSO algorithm in conducting an energy storage system (ESS) planning exercise to improve network reliability. While the study assessed reliability-cost trade-offs, in terms of energy not served (ENS) compared against the cost of ESS and total operation cost, including a sensitivity analysis, the study was focused on the radial electrical distribution network. (Baghaee et al., 2016) utilised a MOPSO algorithm to solve reliability/cost based optimal design of a hybrid wind/PV with hydrogen storage system. While the study considered a few operation reliability indices and one year period of hourly time steps operation, the analysis was done using a synthetical load data and for a micro grid.

How reliability can be enhanced without compromising the affordability of the electricity system have been discussed in (Al-Shaalan, 2011), (Al-Shaalan, 2017). While these studies explained the important relationship between cost and reliability, they have been focused only on integrating isolated existing systems without considering any VRE penetration nor other externalities such as emissions. These two aspects may significantly affect effective planning due to the trade-offs between security and economics. (Röpke, 2013) applied a cost-benefit approach to analyse the trade-offs between RE development and supply security (reliability) targets on the German electricity market between 2010 and 2020. While the reliability levels are compared with costs, the study focused on reliability problems of the distribution grid due to the increase of decentralised RE production. (Wu et al., 2008) applied the Monte Carlo method to develop a stochastic long-term optimisation-based model for calculating the cost of power system reliability. While the study considered the trade-off between minimising operating costs and satisfying reliability requirements, the analysis has been undertaken as a stochastic security-constraint unit commitment problem.

Reliability in planning exercises is often 'set' through a constraint on Unserved Energy (USE). This may be set at zero reflecting that supply must always meet demand over the planning horizon. More sophisticated modelling often permits some fixed level of USE, perhaps matched to the target reliability for that jurisdiction. These targets reflect the reality that absolute 100.000% reliability can involve significantly higher industry costs given the additional generation and network capacity required to cover unexpected plant and network failures. Still, for developed countries these reliability targets are often very tight - for example, the Australian reliability standard is 0.002% USE (AEMO, 2019). Such targets reflect very high expectations on supply reliability and Value of Lost Load (VOLL) estimations, the USE price ($/MWh) at which the cost of providing greater reliability starts to exceed the value of this reliability to consumers.

This chapter presents new perspectives by addressing two complexities for electricity generation planning studies that have not been fully explored to date. The first is that it explicitly explores the trade-off between future power system reliability and total generation costs, for electricity industries in emerging economies. While the very tight reliability targets generally used for modelling exercises are likely appropriate for developed electricity sectors with very high delivered reliability, many emerging economies achieve much lower reliability in practice. It is not uncommon for electricity users to suffer regular supply interruptions on near monthly, weekly, or even a daily basis. A 0.002% USE for future generation mixes misses the reality of these industry sectors. The second complexity is the implications of growing VRE penetrations on reliability. This study models variable wind and solar PV generation with high temporal (hourly) and locational (choosing traces from a range of solar and wind locations) fidelity using an open-source evolutionary programming-based tool. While wind and solar now offer amongst the lowest levelized costs of electricity in many jurisdictions, their highly variable and somewhat unpredictable output raises additional reliability challenges to that posed by unexpected peak demand growth and conventional generator and network failures. Two broad questions are brought together in this study, in the context of emerging economies' electricity industry planning: appropriate system operational reliability standards, and the impacts of high VRE penetrations modelled at high temporal resolution on reliability.

In terms of methods, this study compares the outcomes and computational effort of achieving different reliability outcomes through setting reliability as a constraint versus applying different prices to any USE. Finally, how policy might drive higher VRE penetrations using carbon pricing is considered, but with a particular focus on how industry costs should be assessed when such 'shadow' externality pricing and hence 'revenue' flows are utilised.

This chapter demonstrates an approach for the case of Indonesia's future Java-Bali electricity grid. This study uses real data of hourly system demand of Java-Bali electricity grid, scaled to account for future demand growth, conducts simulations to obtain optimum possible future generation portfolios with high VRE penetrations under a range of reliability standards and carbon prices, and examines their impact on the associated generation costs and emissions. While the study is focused on Indonesia, electricity supply reliability poses challenges for many other emerging economies, including those with relatively high rates of access, given the challenges of demand growth and raising the capital required for investment to meet this (Foster and Rana, 2020), (Gertler et al., 2017). Therefore, while the Indonesian electricity industry is used as a case study, the method used, and insights obtained from the analyses presented in this paper are highly relevant to other jurisdictions with similar contexts.

It is important to note here that the reliability of electricity provision has enormous significance for energy users - residential, commercial, and industrial - and that the private and broader societal costs of relatively poor reliability in many emerging economies are poorly understood but likely large. Also, the reasons for supply interruptions may have many causes other than insufficient generation capacity, often relating to grid overloading or failure. Such realities mean that many industries, commercial and even residential participants have sought self-supply options to cover grid outages, and major cost additions to improve reliability may prove challenging for many consumers. In particular, this study is not arguing that electricity consumers in these jurisdictions would not value greater reliability, but rather acknowledging the realities of achieved reliability at present and seeking to better understand potential cost-reliability trade-offs. Work to better understand the impacts of different levels of reliability on the demand-side is beyond the scope of this study, but clearly needed.

The rest of this chapter is organised as follows. Section 7.2 briefly discusses the emerging economies' context for electricity industry planning, focussing on Indonesia's power sector as the selected case study. Section 7.3 describes the method applied in this study, simulation overview, scenarios and assumptions, and the data inputs for scenario modelling. Results and discussions are presented in Section 7.4, and finally, Section 7.5 concludes the chapter.

7.2 Emerging economies' context for electricity industry planning: A case study of Indonesia

Electricity industries in many emerging economies are characterised by having significant demand growth and, hence, investment challenges, and a present reliance on fossil-fuel generation despite excellent renewable resources, including VRE. This study uses the Indonesian electricity industry, especially the Java-Bali grid, as a case study given its high relevance to many other electricity industries in other emerging economies in terms of underlying resources, present fossil fuel reliance, reliability and investment challenges, and policy gaps for transitioning towards a more sustainable future.

An overview of the current Indonesian institutional power sector situation, in terms of national power sector profile and in particular the Java-Bali grid, and long-term electricity generation planning, are presented and discussed in Chapter 2 (Section 2.3.3). Subsequently, challenges and current drivers of Indonesia's electricity industry, including governance barriers and PLN's long-term planning, regulatory barriers, status of large-scale solar PV and wind deployment, long-term domination of coal, and climate change mitigation, are also elaborated in Section 2.3.4.

This all suggests a need for more transparency and participation in planning by a wider range of stakeholders, and that Indonesia – and also other jurisdictions with similar contexts - should rethink commitment to plants that involve rapid expansion of coal capacity, given various international pressures and growing investor unwillingness to take on exposure to coal. Consequent with this, is a need to better understand the range of options, particularly with high RE penetrations – including solar and wind.

7.3 Method

In this study, future electricity generation scenarios with high VRE penetrations for Indonesia's Java-Bali grid are considered, capturing the complexities of Java-Bali solar and wind generation potential in terms of their hourly output variability and uncertainty (see Section 7.3.5 for more details), as well as Java-Bali hourly dynamic system demand (see Section 7.3.4 for more details) for a future year 2030. Appropriately capturing these dynamics in long-term generation planning, including renewables supply and system demand, requires use of a chronological dispatch model (tool).

7.3.1 Simulation overview

National Electricity Market Optimiser (NEMO) model, as previously presented and used in Chapter 6, is also applied in this study, to solve possible optimum (least-cost) generation portfolios including generation capacity mix, total generation cost, and CO_2 emissions, among other parameters, subject to a range of system reliability targets and different carbon prices (CP) under high VRE penetrations. The analysis uses two different approaches (hereafter methods) to include a wide range of reliability standards in the optimisation, as described below. This chapter also presents scenarios, parameters, and assumptions for the case study, followed by demand data and technology cost data.

7.3.2 Methods for incorporating reliability in the optimisation algorithm

Modelling long-term electricity industry planning for our study also requires inputting reliability of supply parameters. Two different methods to represent reliability in the optimisation algorithm are used in this study. In the first method, reliability is represented as an optimisation constraint by setting a certain value of USE applied for a whole year of simulated operation. USE is used to represent the level of grid reliability, expressed as a percentage of total unserved load over the total system demand in a year, given hourly traceable generation supply and demand resolution. Nevertheless, it should be noted that other reliability parameters might also be applied for electricity industry planning and operation purposes in different countries. This study considers eight different USE limits, i.e., 0.005%, 0.05%, 0.5%, 1%, 2%, 3%, 4%, and 5%, and imposes these fixed USE limits as hard maximum limits on the allowed USE. The reliability level of 0.005% USE is reasonable for this study considering the applicability of highly planned and achieved reliability in developed countries, taking the Australian National Energy Market (NEM) with 0.002% USE as an example (AEMO, 2018). Higher USE of up to 5% are also applied in this study to test potential implications of having broader reliability, i.e., by pushing the reliability up to 5% USE beyond what have typically used in the planning. Besides, as for the case of emerging economies, there are challenges in terms of achieved reliability in Indonesia (Kunaifi and Reinders, 2018), (PLN, 2020). Finally, there is growing demand flexibility in the electricity sector and in some regards higher USE standards can also reflex this circumstance, i.e., particular loads do not always need to be supplied can have major implications for industry costs.

Another approach is to place a typically very high penalty or 'Value of Lost Load' (VLL) price ($/MWh) to any USE so that the cost minimization sets USE at the efficient level where the cost of increasingly reliability is not worth the value of this reliability to end consumers. In practice, setting these reliability targets or penalty prices involves some sense of this trade-off between reliability and cost. In the second method, therefore, different penalty costs/prices ($/MWh) are applied for the USE. The purpose of applying this method is to provide an alternative way to determine the least-cost generation mix for different levels of reliability, without having a predetermined USE constraint imposed on the simulations.

The reliability cost component represents the cost in $/MWh that is borne by the system as a penalty for not meeting a MWh demand. This penalty charge is effectively 'tuned' through iterative runs of NEMO until the simulation achieves delivered %USE outcomes equivalent to the reliability levels (ranging from 0.005% to 5%) used when setting this as a constraint.

While this study uses %USE to represent the level of grid supply reliability in an hourly supply-demand resolution, it is calculated over the planning horizon, for example a certain year in the future. This study does not assess or incorporate reserve margins (e.g., an operating reserve requirement of capacity above peak demand) into the analysis. NEMO can model system with reserves, and the implications of reliability levels, as measured by USE target, on dynamic operating reserve margins are discussed in Chapter 9.

7.3.3 Scenario, parameters, and assumptions

The analysis considers different carbon prices (CP) as a proxy for a potentially wide range of policies that could deliver greater future VRE penetrations. This study chooses $0/t$CO_2$ (CP0), $35/t$CO_2$ (CP35) and $60/t$CO_2$ (CP60), to reflect Indonesia's possible future policy settings on emissions reduction commitments, as well as to capture some uncertainties around future fuel costs and costs of funding increasingly risky fossil fuel projects (Simaremare et al., 2017). As in Chapter 6, this study also applies a 5% discount rate on annualised technology capital cost and a maximum permitted non-synchronous penetration of 0.75. Coal and gas prices are assumed at $3.5/GJ and $10.9/GJ, respectively, following (IRENA, 2017b) and also as applied in Chapter 6 as the fuel cost baseline.

In this study, total industry generation costs are observed, either in $/total MWh of demand or $/MWh of actual energy served and, according to the treatment of carbon revenue (CR), included in total industry costs or not. In terms of the analysis of emissions outcomes, this study also uses tCO_2/MWh energy served as an indicator of the environmental outcomes of different generation portfolios. As in Chapter 6, this study does not model transmission networks and other related investment requirements.

7.3.4 Demand data

The same 2015 Java-Bali hourly demand dataset is used as a baseline for demand, as in Chapter 6 (Section 6.2.2.2). An, arguably conservative, linear annual growth rate of 5% is assumed in this study to create a projected 2030 demand profile based on the 2015 baseline, considering historical average annual growth in the region (Tanoto et al., 2020), yet also the slowing down of national economic growth in the past few years, unmet targets for national generation expansion and the uncertainty in the global future economic outlook and vulnerability of developing countries against global energy commodities. The linearity of the annual growth rate on demand projection for future generation scenarios has also been applied in (Simaremare et al., 2017). The analysis considers a single value of growth rate as it focuses more on the solution space analysis of the results obtained from the least-cost mix simulation framework, rather than just comparing optimal solutions of different demand scenarios. As a consequence, the modelling sees an energy demand profile of 346.5 TWh and 50 GW peak load by 2030.

7.3.5 RE generation potential data

This study applies the same data, in terms of 2015 one-year of gridded hourly solar PV power output data, as used in Chapter 6 (Section 6.2.1 and Section 6.2.2.4) and follows the methodology used in (Tanoto et al., 2017), (Tanoto et al., 2020). Up to six locations are assigned a PV plant candidate trace, one location in each province covered by the Java-Bali grid, considering factors such as high-capacity factor, low hourly temporal variability and low spatial variability in addition to the terrain and proximity to volcanoes.

Hourly wind power output traces for selected locations for the year 2015 are also obtained from the online tool Renewable Ninja (RN) (Pfenninger and Staffell, 2016). Locations assigned for wind plant candidates are chosen using the Indonesia wind prospecting map (A/S, 2017). Despite the potential capacity of solar and wind mentioned for the Java-Bali grid in the literature (IRENA, 2017b), (NREEC, 2017), (Veldhuis and Reinders, 2013), PV and wind build capacities are not capped in this study, considering high uncertainty of their potential output. Meanwhile, as in Chapter 6 (see Section 6.2.2.3), build limits for geothermal and hydro are also set at 10 GW and 8 GW, respectively.

7.3.6 Technology cost data

The technology cost components used in this study are presented in Table 7.1 (Tanoto et al., 2020).

No.	Technology	Capital ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)
1.	Coal	1,360	35.8	3.8
2.	OCGT	400	22.5	3.8
3.	CCGT	710	22.5	3.8
4.	Biomass	1,600	43.8	6.5
5.	Geothermal (Geo)	3,200	16.7	0.7
6.	Hydro	2,000	35.8	3.8
7.	Wind onshore	1,310	52	0.8
8.	Solar PV fixed	610	12.5	0.4

Table 7.1: Mid-level 2030 technology cost components

This study considers the same generation technology candidates as used in Chapter 6, i.e., coal fired power plant, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT), geothermal, hydropower, biomass and VRE, which includes PV, and onshore wind turbines. This study confirms the use of mid-level 2030 technology costs scenarios, compiled from reports published by Indonesia National Energy Council (DEN, 2017), (DEN, 2016) after further comparison and verification against other costs dataset (IEA, 2015), (LAZARD, 2017), (NREL, 2017). While the technology costs structure as shown in Table 7.1 is specific to this study, its assumptions are mostly either similar or within the range of other costs datasets that were investigated. However, these assumptions are just that, assumptions, and ongoing technology progress will see them change. They are also calculated in different ways, and not always consistently. As on example, the high estimates for fixed O&M cost of onshore wind compared with some other RE technologies in Indonesia could be caused by either higher insurance/administration, or fixed grid access fees and service contracts for scheduled maintenance. Meanwhile, the high variable O&M cost for Biomass is considered as it is mainly impacted by the feedstock cost (IEA, 2015).

It is obvious that the results presented in this study, i.e., analysis of cost-reliability trade-offs and its implications for the capacity and generation mix, depend greatly upon the technology costs assumed for the assessment. In recent years, the costs of some mature RE technologies such as PV and onshore wind have significantly decreased (REN21, 2016).

The current range of generation costs for fossil fuel capacity in Indonesia is about $75-150/MWh, while weighted average levelized cost of electricity from major VRE technologies such as onshore wind, hydro, and geothermal are already within that range, except for PV (IRENA, 2017b). Therefore, significant changes in technology costs, especially for RE, could change the specific results of these analyses, mostly in terms of making VRE more attractive.

7.4 Results and discussions

This section presents and elaborates specific results for the Java-Bali grid case study. Initially, it shows and describes results for the default case as shown in Section 7.4.1, followed by results for the possible optimum generation capacity portfolios, as obtained from the simulations using method 1 (Section 7.4.2) and method 2 (Section 7.4.3), and CO_2 emissions outcomes (Section 7.4.4).

The future generation scenarios problem is modelled in two ways; first by treating USE in one set of modelling as an exogeneous constraint input, and then secondly as a cost associated with any USE. This section compares the results and computational ease of both approaches, while focussing on the actual reliability and cost trade-offs.

7.4.1 Default case

The least cost 2030 Indonesia's Java-Bali generation portfolios are first assessed as a default case by imposing a single fixed reliability constraint of 0.002% USE as a baseline scenario. This relatively high reliability standard is applied as it is currently the Australian National Electricity Market standard (Elliston et al., 2013). The generation technology candidates consist of different generation technologies as shown in Table 7.1. The default case study applies three CP scenarios: no CP or CP0, \$35/tCO_2 or CP35, and \$60/tCO_2 or CP60. The optimum solutions are found for all CPs using NEMO as briefly described in earlier section. The least-cost capacity and generation mixes of the default case with and without CPs are shown in Figure 7.1.

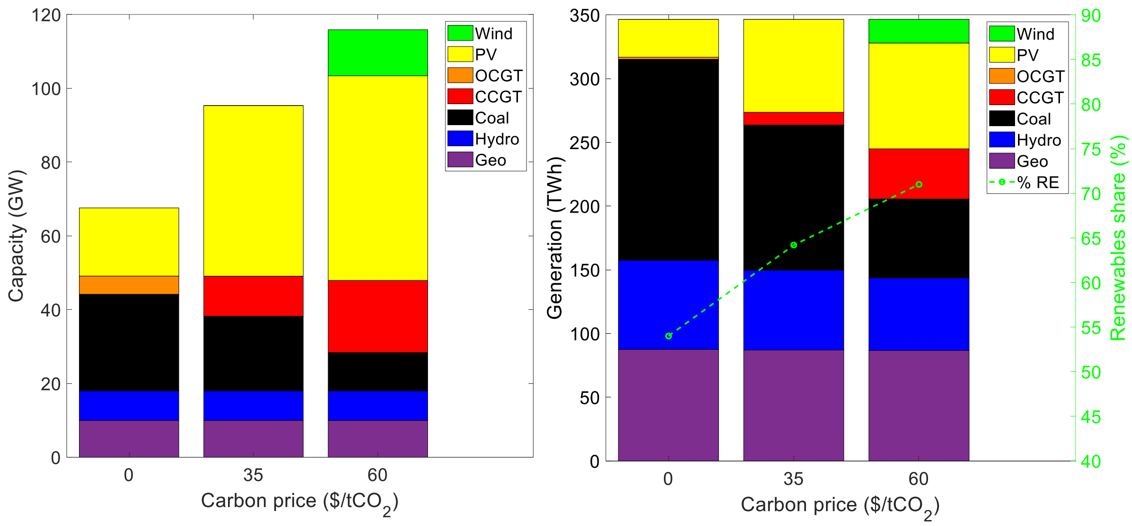


Figure 7.1: Capacity (left) and generation mix (right) of the least cost default planning with CP0, CP35, and CP60

The results highlight that while Geothermal and Hydro capacity hit their maximum allowed GW for all CP scenarios, the higher CP drives more PV (and at CP60 wind) as well as greater CCGT capacity addition. The share of RE including VRE in the generation mix increases from 54% to 64% and 71% in CP35 and CP60, respectively. On the other side, coal share decreases from 46% in CP0 to 33% and 18% in CP35 and CP60, respectively.

While imposing CPs would see higher generation costs due to the additional cost associated with cleaner technologies, as well as the direct carbon cost, the collected revenue (CR) from imposing CPs can be used to provide cross-subsidies to groups of consumers who are most vulnerable to higher price of electricity under this scheme and also for other social welfare purposes. Therefore, the total costs of industry excluding the carbon revenue (CR) are also estimated. Variations in the total cost excluding CR, simulated USE, and the share of VRE among the optimum capacity mixes for all CPs are presented in Table 7.2.

CP in \$/tCO_2	Total cost incl. CR in b\$/year	Total cost excl. CR in b\$/year	Simulated USE in percentage	VRE share in percentage
0	14.0	14.0	0.002	8.6
35	18.3 (30.7%*)	14.3 (2.1%**)	0.002	21.0
60	20.9 (49.3%*)	16.4 (17.1%**)	0.002	29.3
*Cost changes between the total cost obtained in the simulation involving CP35 and CP60 versus CP0; **Cost changes between total costs after taking carbon revenue out.				

Table 7.2: Total cost, simulated USE and VRE share using 0.002% USE as a reliability constraint

From Table 7.2, carbon revenue for CP35 and CP60 can be calculated to be b\$4/year and b\$4.5/year, respectively. Interestingly, almost doubling the CP has only a modest increase in carbon revenue given that it drives greater deployment of PV, wind and gas generation. CO_2 emissions fall in CP35 and CP60 from 154 MtCO_2 in CP0 to 114 MtCO_2 and further to 76 MtCO_2, respectively.

As noted above, achieving a relatively high-reliability level is difficult in developing countries. Therefore, this study also considers lesser reliability standards to explore the optimum solution space in terms of a possible range of costs and acceptable reliability settings in the presence of high VRE penetrations. In following sections, we present results obtained from the simulations using two different methods in the optimisations, as described earlier.

7.4.2 Method 1: fixed USE limit

Considering a range of reliability levels, this study shows that, as expected, the total generation costs of the optimum (least-cost) portfolio mixes decrease as lower reliability standards are imposed. In all simulations without CP, the total generation costs decrease from b\$14/year to b\$12.1/year, or a 13% reduction, associated with 0.005% USE and 5% USE, respectively. With the same reliability range, the costs in CP35 are reduced from b\$18.4/year to b\$16/year, also a 13% reduction. In CP60, the costs are decreasing from b\$20.9/year to b\$18.2/year, also equivalent to a 13% reduction. Thus, all simulations produce around 13% cost reduction from the highest to the lowest reliability standards. It should be noted that CR is included in all results.

Table 7.2 (left) presents plots of the total generation costs, expressed in b$/year, versus USE for all optimum generation mixes and CPs. It also shows the cost trend if CRs are excluded from the total costs obtained in CP35 and CP60. A comparison between total generation costs, expressed in $/total MWh and $/MWh energy served versus USE is presented in Table 7.2 (right), with and without CR embedded in the costs.

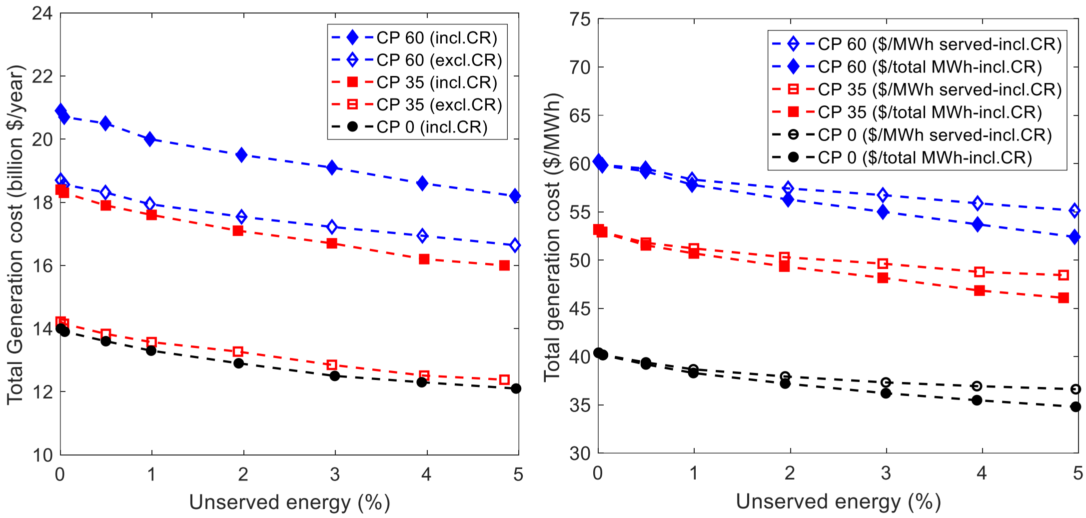


Figure 7.2: Total generation costs versus realized USE, expressed in b$/year (left), and total generation costs versus realized USE, expressed in $/total MWh and $/MWh served (right), for all CPs

The fall in total industry costs through relaxing the reliability standard is significant in terms of total industry costs and average $/MWh costs. As expected, $/MWh-served cost reductions decrease as USE increases given that less MWh are delivered. A higher difference between $/total MWh and $/MWh served is observed as reliability is further relaxed. Cost reduction expressed in b$/year and $/MWh served are presented in Table 7.3, highlighting relatively similar cost reductions across all the three CP scenarios.

CP ($/t$CO_2$)	Cost incl. CRs (b$/year)			Cost incl. CRs ($/MWh served)		
	0.005% USE	5% USE	Cost reduction (%)	0.005% USE	5% USE	Cost reduction (%)
0	14.0	12.1	13.5	40.39	36.62	9.3
35	18.4	16.0	13.0	53.17	48.44	8.9
60	20.9	18.2	12.9	60.24	55.13	8.5

Table 7.3: Cost for the highest and the lowest reliability level, in $/year and $/MWh served

For CP0, the total system cost decreases from b$14/year to b$12.1/year as USE limit drops from 0.005% to 5%. In other words, there would be around b$0.38/year on average that might need to be spent to increase the system reliability by 1%, with additional costs at around b$0.48/year and b$0.54/year for CP35 and CP60, respectively.

Figure 7.3 shows the capacity and generation share of different technologies under different USE limits for CP0. PV capacity grows from 23 GW to 31 GW as reliability is relaxed to 5%. Coal capacity, on the other hand, reduces from 27 GW to around 18 GW. OCGT appears only in less than 0.05% USE which highlights the role of this peaking plant in meeting the rare peak times which could have been unserved with a lower reliability limit. In the generation mix (right figure), RE penetrations increase from 56.4% to 61.6%.

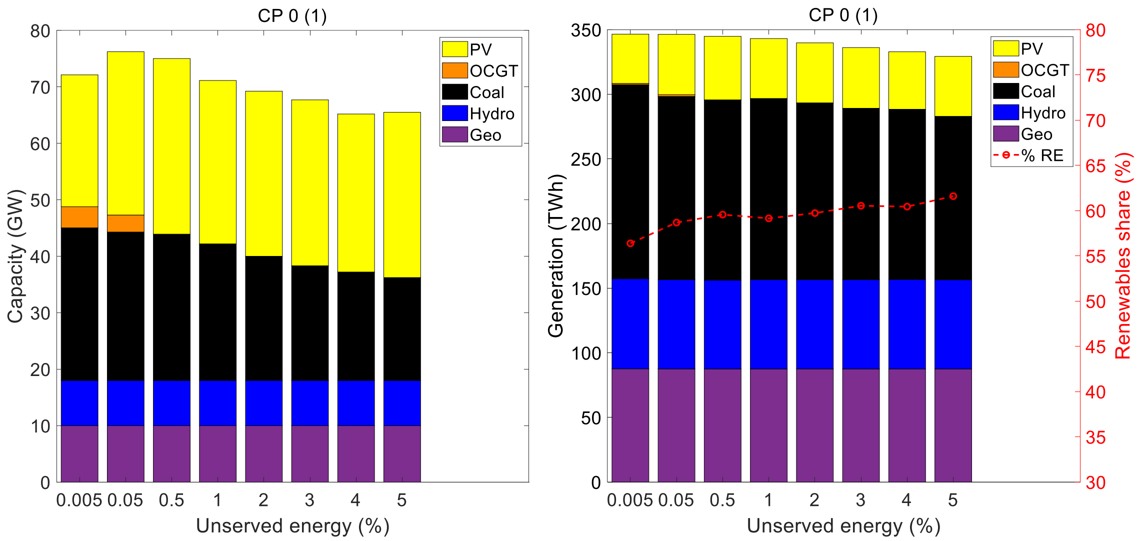


Figure 7.3: (Left) Capacity mix and (right) corresponding generation mix and RE share of the optimum future mix, allowing different USE limits imposed as a reliability constraint and CP0

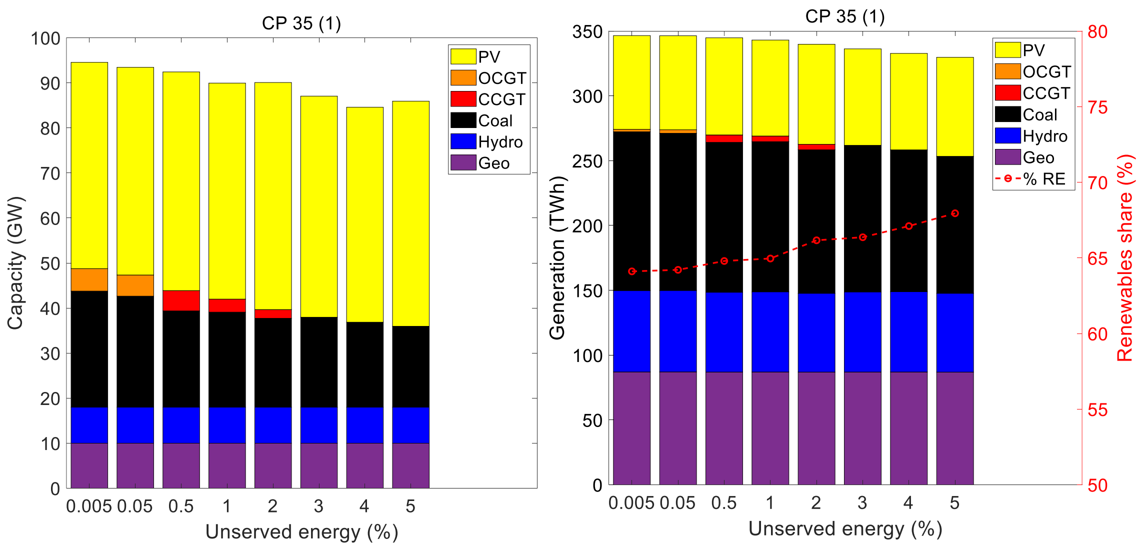


Figure 7.4: (Left) Capacity mix and (right) corresponding generation mix and RE share of the optimum future mix, allowing different USE limits imposed as a reliability constraint and CP35

In simulations with CP35 (as shown in Figure 7.4), some gas-based generation exists up to a 2% USE limit. As the USE target is relaxed, OCGT is displaced by CCGT and then by VRE. Energy generation from coal is decreased to around 22% and 20% at 0.005% and 5% USE limits, respectively. A higher capacity of PV is obtained at this CP compared to CP0. For 0.005% and 5% USE limit, PV capacity reaches 45.78 GW and 49.97 GW, respectively. As seen in Figure 7.4 (right), RE shares for the highest to the lowest reliability range from 64.11% to 67.95% while VRE shares are 20.87% at 0.005% USE limit and increase up to 23.17% at a 5% USE limit.

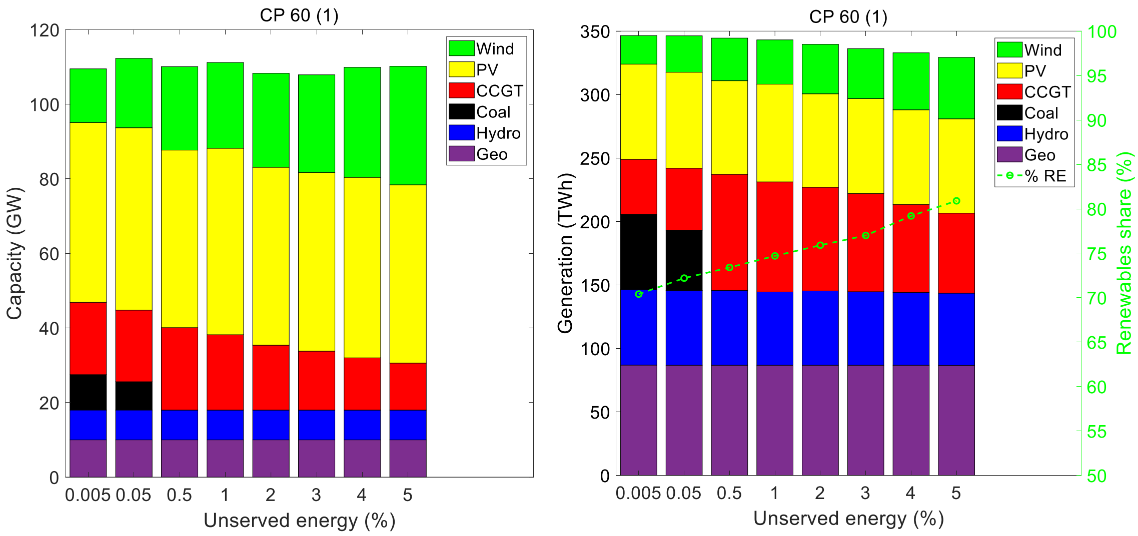


Figure 7.5: (Left) Capacity mix and (right) corresponding generation mix and RE share of the optimum future mix, allowing different USE limits imposed as a reliability constraint and CP60

In CP60, the majority of coal capacity in the optimum mixes is replaced by CCGT, across all reliability standards, in addition to extensive solar and wind penetrations. The simulation also finds a relatively similar PV capacity of 50 GW for all reliability levels while wind capacity doubles from 14.4 GW at 0.005% USE limit to 31.8 GW at a 5% USE limit, and coal capacity exists only at 0.005% and 0.05% USE limits. As depicted in Figure 7.5 (right), RE generation shares increase roughly 10.5% from 0.005% to 5% USE limits.

For all CP, greater drops in the total generation costs have been identified within 0.005% to 1% USE given significant reduction of fossil fuel-based capacity, either coal or gas, across these higher reliability levels. As might be expected from the outcomes of capacity mixes, industry costs fall far less across the reliability range of 1% to 5% USE as the highest value opportunities to avoid capital investment have already been achieved.

7.4.3 Method 2: priced USE

This section presents findings obtained using method 2 and their comparison with those revealed from simulations using method 1. To permit comparison, the penalty prices are tuned on USE $/MWh so that the optimisation delivers the USE targets used in method 1. For example, the realised cost of USE of $68/MWh delivers 5% USE. The tuned costs of USE along with the corresponding USE levels are shown in Figure 7.6 (left), while results with CP35 and CP60 are presented in Figure 7.7 and Figure 7.8, respectively. For generation costs with CR included, the costs obtained from method 2 are similar to those using method 1 when excluding the realised penalty cost component. A comparison between generation costs obtained from both methods is presented in Table 7.4. Meanwhile, Table 7.5 presents the total cost of the industry and penalty cost components obtained from simulations using method 2.

USE level (%)	Method 1			Method 2#		
	CP0	CP35	CP60	CP0	CP35	CP60
0.005	14.0	18.4	20.9	14.0	18.4	20.8
0.5	13.6	17.9	20.5	13.5	17.8	20.3
1	13.3	17.6	20.0	13.3	17.5	19.9
2	12.9	17.1	19.5	12.8	17.0	19.4
3	12.5	16.7	19.1	12.5	16.6	18.9
4	12.3	16.2	18.6	12.3	16.2	18.5
5	12.1	16.0	18.2	12.0	15.8	18.1
#Realised penalty cost component is excluded.						

Table 7.4: Comparison of generation cost of the least cost portfolios mix including CR (in b$/year)

USE level (%)	CP0		CP35		CP60	
	Total cost	Penalty	Total cost	Penalty	Total cost	Penalty
0.005	14.0	0.02	18.5	0.02	20.9	0.03
0.5	13.8	0.34	18.1	0.27	20.7	0.37
1	13.7	0.49	18.0	0.50	20.6	0.62
2	13.5	0.72	17.9	0.97	20.4	0.97
3	13.4	0.88	17.8	1.20	20.3	1.39
4	13.3	1.01	17.6	1.49	20.3	1.79
5	13.2	1.18	17.6	1.81	20.2	2.19

Table 7.5: Total cost of industry and penalty cost of the least-cost mix using method 2 (in b$/year)

The analysis shows that NEMO was able to solve the same costs and generation mix, modelling reliability through either a fixed USE constraint or by pricing USE in the cost minimisation function. As noted in Section 3.2, this involved a 'tuning' process where NEMO was run with different penalty costs ($/MWh) until it delivered USE% broadly equal to the range of USE tested using the constraint approach. The penalty price approach does have one particular advantage for evolutionary computation, where hard constraints can cause challenges for the evolutionary process in trying to get as close as possible to, while not exceeding, this reliability target.

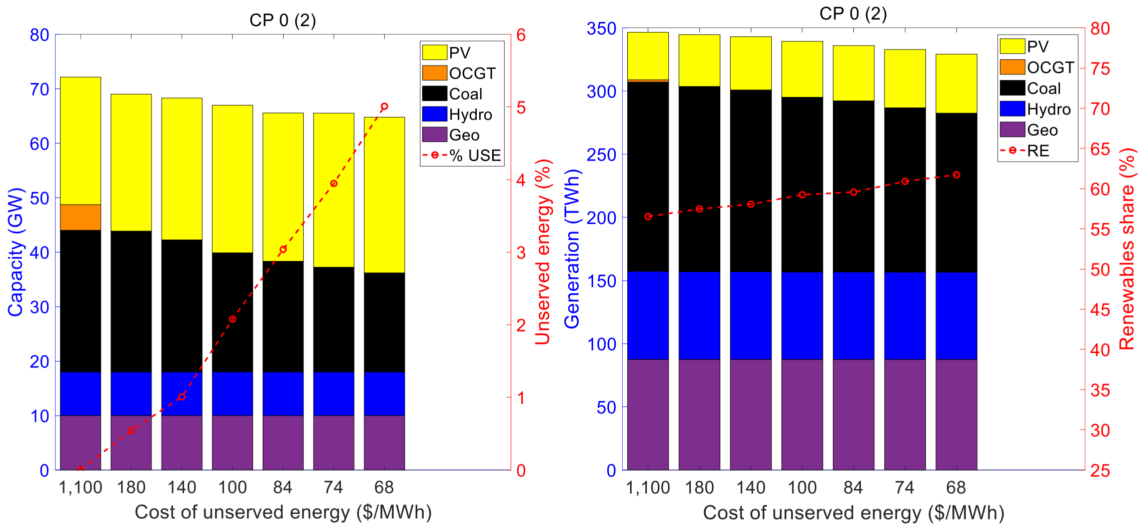


Figure 7.6: (Left) Least cost capacity mix and corresponding USE and (right) least-cost generation mix and RE shares for CP0

As shown in Figure 7.6 to Figure 7.8, this method tends to provide a smoother trend of capacity mix outputs. Still, similar results of RE generation shares in the optimum generation mixes using method 1 and method 2 are achieved, as shown in Table 7.6.

USE level (%)	Method 1			Method 2		
	CP0	CP35	CP60	CP0	CP35	CP60
0.005	56.4	64.1	70.4	56.5	64.0	70.6
5	61.6	68.0	80.8	61.7	67.9	80.1

Table 7.6: Comparison of RE generation shares in the optimum generation mixes (in %)

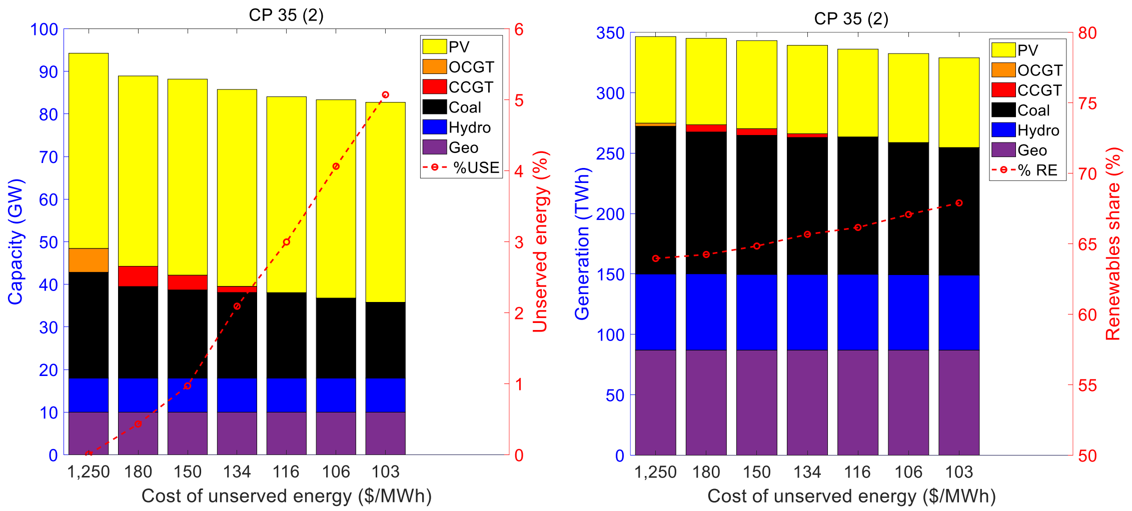


Figure 7.7: (Left) Least cost capacity mix and corresponding USE and (right) least-cost generation mix and RE shares for CP35

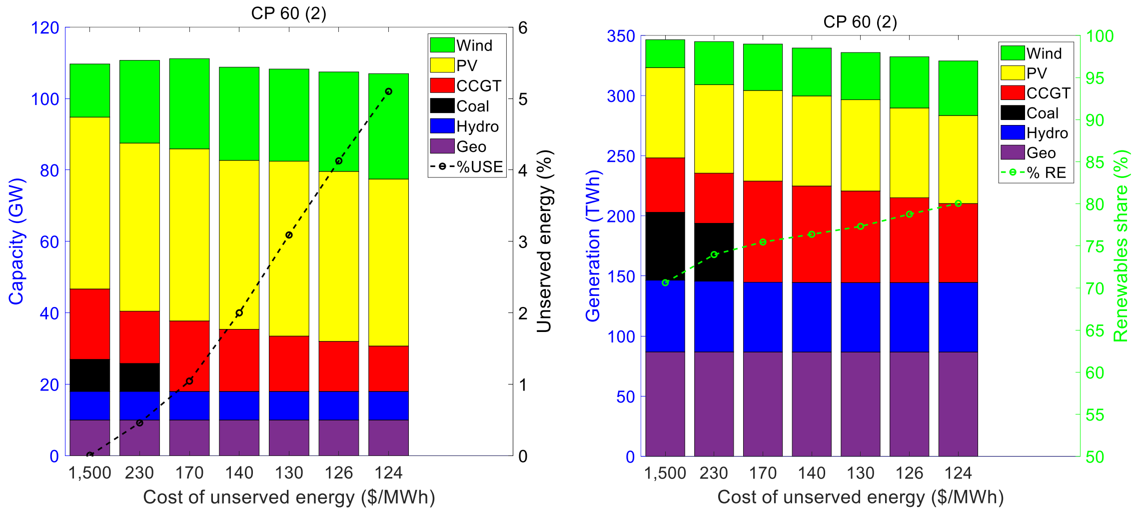


Figure 7.8: (Left) Least cost capacity mix and corresponding USE and (right) least-cost generation mix and RE shares for CP60

While the total generation cost for each least-cost portfolio comprises both capital and operating costs, the comparison of total generation costs between method 1 and 2, as in Table 7.4 and also in Table 7.5, are presented in $/year other than $/MWh. Representing the cost in $/year is particularly helpful for policymakers and system planners in analysing, for example, the total annual cost requirement of the industry, or for budgeting and investment purposes. Besides, the realised penalty cost component is easier to be identified when the total cost is represented in $/year.

Given the easier and more stable computation using penalty pricing rather than hard constraints, the simulation findings suggest that it might be the preferred approach for modelling reliability and cost trade-offs with evolutionary programming. Other solution approaches such as LP may of course exhibit different behaviours across these two approaches.

7.4.4 CO_2 emissions outcomes

Total CO_2 emissions obtained from method 2, expressed in $MtCO_2$ and tCO_2/MWh served, across simulated reliability standards are shown in Figure 7.9. The total CO_2 emissions in CP0 decreased from 146.4 $MtCO_2$ at 0.005% USE limit to 122.2 $MtCO_2$ at 5% USE limit, around a 16.5% decrease. CP35 scenario shows a similar percentage emissions reduction from 120.2 $MtCO_2$ to 102.4 $MtCO_2$.

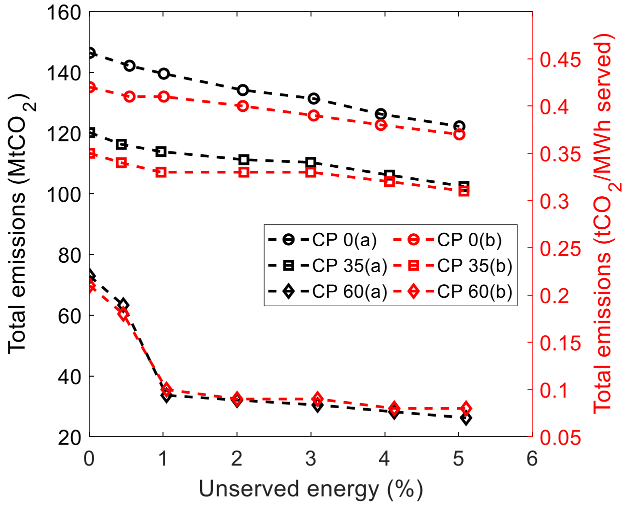


Figure 7.9: Total CO_2 emissions of least-cost mixes (dashed-black colour lines), and CO_2 emissions per MWh served (dashed-red colour lines) versus realized USE for all CPs using method 2

The downtrend of the total emissions due to larger USE level is shown by the dashed black lines. A significant drop in CO_2 emissions is obtained in CP60 from 72.9 $MtCO_2$ to 26.2 $MtCO_2$, equivalent to a 64% drop. A similar declining trend is also observed in tCO_2/MWh energy served (dashed-red lines), showing how reducing reliability requirements not only reduces total and $/MWh industry costs but also CO_2 emissions. The largest reduction is obtained for CP60, in which CO_2 emissions are falling from 0.21 tCO_2/MWh to 0.08 tCO_2/MWh, or around 62%.

The change of technology in the least cost generation mix in CP60, i.e., from 0.005% USE with roughly 160 TWh coal into no more coal in 1% USE (coal is replaced with more CCGT and wind) delivers a major decline in CO_2 emissions falling from 0.21 tCO_2/MWh to less than 0.1 tCO_2/MWh, or around half of the total emissions in $MtCO_2$. This highlights the benefits that relaxed reliability standards can deliver in terms of supporting greater VRE deployment.

In summary, the modelling results suggest that using lower reliability standards in generation planning might not only reduce total $/year and average $/MWh industry costs but can also facilitate greater VRE deployment and consequent emissions reductions. Imposing a CP can also greatly reduce emissions and the industry cost increases may not be as significant as feared, provided the special nature of carbon revenues are appropriately factored into the analysis. The emission outcomes of Figure 7.9 highlight the potential major opportunity to deliver much lower industry emissions through CP and more relaxed reliability standards.

7.5 Conclusions

Electricity industry planning in emerging economies is an enormously challenging task given the need to meet growing demand despite challenges in financing investment. Poor reliability outcomes often result, while adverse environmental impacts are, understandably, not given great weight. Wind and solar PV offer extraordinary potential to assist these electricity industries to meet growing demand at reasonable cost whilst greatly improving environmental outcomes.

New perspectives on these challenges are provided in this study by exploring the implications of different reliability standards, including relatively high USE, on generation costs for future electricity generation mixes with high VRE scenarios. While undertaking long-term planning, this study also models variable wind and solar generation with very high temporal (hourly) and locational (choosing traces from a range of solar and wind locations) fidelity. The two methods compare different reliability outcomes through imposing reliability as a constraint versus applying different prices on any USE. This study also considers the use of carbon pricing to encourage higher RE penetrations and utilises 'shadow' externality pricing and hence 'revenue' flows in the analysis.

While the broad topic of reliability-cost trade-offs for future electricity generation scenarios has, of course, already received considerable attention in the literature, reliability targets has typically been fixed at very high levels in electricity generation planning exercises. In addition to imposing reliability as a constraint, this study explicitly prices the impacts of different reliability targets, in the context of emerging economies where electricity industry reliability is often significantly lower than that achieved in industrialised economies, and with high VRE penetrations. this study brings together two broad issues, i.e., appropriate operational reliability standards and the complexities of high VRE penetrations in the context of emerging economies' electricity industry planning.

These methods are applied to assess possible optimum generation capacity portfolios for different reliability levels and CPs for the Java-Bali grid. The simulation results using both reliability methods exhibit similar results in terms of increasing penetration of RE, including VRE, notable reduction in total generation costs, and a wide span of CO_2 emissions reduction, although placing reliability in the cost function rather than constraint set would seem to offer computational advantages.

While the study has shared some similar fundamental settings and basic assumptions for simulations to those applied in Chapter 6, and as anticipated, has produced a similar generation capacity mix with the domination of coal and less than 15% generation share of solar PV in the default case with CP0 and 0.002% USE, the modelling research has highlighted a wide array of possible outcomes associated to the methods.

The results show a similar 5% to 10% increased renewables share as CP increases by relaxing the reliability target from 0.005% USE to 5% USE. The least cost generation mix has 60%, 68%, and

80% renewables share at 5% USE for CP0, CP35, and CP60, respectively. Meanwhile, cost reductions (in \$/year including carbon revenue) of around 13% are obtained across all CP scenarios when shifting from 0.005% USE to 5% USE in the first method. This is equivalent to a cost reduction of around 9% in \$/MWh served. While CO_2 emissions reductions from greater VRE deployment are seen as %USE increases, imposing CP can significantly help to further reduce total CO_2 emissions in terms of both $MtCO_2$ and tCO_2/MWh served.

This study does not conclude that emerging economies should target lower reliability levels than industrialised economies. However, it highlights the potentially significant overall industry cost reductions associated with lower reliability targets. Future work is, however, required to better understand the implications of this for electricity consumers in emerging economies, noting that they generally experience far lower reliability than consumers in industrialised economies.

While specific findings obtained from this study are relevant to the Java-Bali electricity grid, the approaches used in this study have broader relevance for electricity industries in other jurisdictions given similar contexts, particularly for planners and policymakers examining the impact of different reliability settings on the economics of different generation capacity expansion pathways. A more flexible approach to reliability targets can not only reduce total generation costs but also support greater use of VRE technologies. Chapter 8 explores trade-offs of key sustainability objectives of sustainable electricity industries in obtaining a possible range of generation portfolios given possible environmentally driven based policy and future uncertainty.

Chapter 8
Clustering Based Assessment of Energy Trilemma Trade-offs for Secure-Affordable-Low Emissions Generation Portfolios in Long-term Electricity Industry Planning

This chapter is based on a paper published in Applied Energy (Elsevier) titled "Clustering based assessment of cost, security and environmental trade-offs with possible future electricity generation portfolios". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship also from Dr. Navid Haghdadi, Dr. Anna Bruce and A/Prof Iain MacGill based on supervision, review, and editing.

This chapter discusses how the concept of energy trilemma can be applied to explore the possible range of generation portfolios given future cost uncertainty, and the trade-offs between the trilemma's key sustainability objectives, involving complex, uncertain, and multi-dimensional choices. The chapter presents novel techniques for assessing possible future electricity industry generation portfolios in three ways: 1) incorporating explicit metrics for energy trilemma's key sustainability objectives into modelling, 2) using the optimisation process of evolutionary programming to map the solution space of 'high performing', near least-cost, portfolio solutions, and 3) applying boundary min-max cases and clustering to categorise these varied portfolios to better facilitate planning and policy making.

8.1 Introduction

The physical characteristics of electricity and the large, interconnected networks that most economically deliver it present specific challenges for managing security of supply, particularly in the context of developing countries. The high capital intensity and long lives of electricity sector assets, their differing contributions to system security, and varied environmental and wider societal impacts all pose considerable difficulties for energy planners seeking to balance social objectives of access and affordability, energy security and environmental sustainability.

Indeed, the term "energy trilemma" (WEC, 2011) is often used to emphasise the potential trade-offs involved across these objectives, while the extraordinary progress seen in wind and photovoltaic generation technologies over the past two decades has added to both the opportunities and the challenges of jurisdictional industry planning to balance this energy trilemma. A number of planning frameworks have used various quantitative metrics for each of these objectives to assess and compare the present sustainability of different electricity sector jurisdictions, changes in jurisdictions over time, and possible future scenarios. Common industry metrics for electricity generation side include total industry costs as a partial measure of affordability, expected unserved energy (USE) for security, and carbon emissions (tCO2) for environmental sustainability. These comparisons often highlight that only a few developed countries have established the highest-balance scores for all trilemma dimensions (WEC, 2018), (Gunningham, 2013).

For developing countries, managing the energy trilemma is generally even more difficult as electricity infrastructure is typically insufficient to meet growing demand within an acceptable range of reliability, budget limitations can reduce options (particularly those with high upfront costs) while many of these countries also face a scarcity of fossil fuel resources.

A review of studies around generation capacity expansion planning with large scale RE integration for different developing jurisdictions using various simulation and optimisation methods and tools was presented in Chapter 3. A recent study has explored energy trilemma in evaluating different energy scenarios that are supporting a more resilient low carbon energy system (Zafeiratou and Spataru, 2018). While an energy trilemma index was utilised in the analysis, this study was focused on the assessment of a single optimum solution, through using a mixed-integer programming tool considering several generation scenarios and interconnection options. However, key uncertainties surrounding future electricity industry planning, such as future costs and environmental policy drivers have not been addressed. Another study has assessed the required CO_2 abatement costs from electrification and CO_2 mitigation trade-offs for the future generation mix in the Java-Bali grid system, Indonesia, given various emissions reduction targets (Handayani et al., 2017). While this study focussed on analysis of the trade-offs between electrification and emissions reduction targets, none of the technical characteristics associated with variable renewable energy (VRE) penetrations, such as temporal variability and/or uncertainty due to resource output fluctuation, is discussed or applied.

Based on these existing studies and the literature review presented earlier in Chapter 3, this study seeks to fill three major gaps and limitations of the work undertaken to date on electricity industry planning with high VRE penetrations, particularly in the context of developing countries. These three gaps are, firstly, that none of these studies explicitly and comprehensively explore the trade-offs, yet also potential synergies, of future generation portfolios across the entire energy trilemma objectives of cost, security, and environmental impacts. This is despite such trade-offs being a key challenge for policy makers and planners, and despite the considerable variation in prioritisation that may be seen across jurisdictions. Secondly, many existing studies have used optimisation techniques that can be problematic for exploring the implications of future uncertainties for energy trilemma objectives, as they typically seek a single 'lowest' cost solution. However, this lowest cost solution will depend on the cost and constraint assumption 'inputs'. A relatively small change in estimated future costs for particular generation technologies (PV is a particularly pertinent example here) may entirely change the 'least cost' outcome. And it may be that a very different generation portfolio is only slightly more expensive but has extremely desirable characteristics for planners in terms of, for example, local industry participation and reduced reliance on fuel imports. Thirdly, none of the existing studies have utilised clustering techniques to present the highly complex choices that result from managing energy trilemma objectives in the area of electricity generation expansion planning. Where efforts to partially map such trade-offs have been undertaken, as in a very few studies, there is the challenge of presenting potentially highly complex choices in a way that is useful to planners and energy policy makers.

This study therefore presents a novel approach that allows a comprehensive assessment and exploration of energy trilemma key metrics for performance of electricity generation planning with high VRE penetrations, using three integrated methods. Firstly, the modelling approach in this study explicitly explores energy trilemma trade-offs between estimated future costs, reliability, and environmental impact, rather than treating one or more of them as constraints. Secondly, this study uses an optimisation tool based on evolutionary programming that can, with modest modifications, provide far more information on the shape of the solution space by explicitly mapping 'near optimal' generation mix solutions. While other optimisation techniques such as linear programming and dynamic programming do provide some guidance on the near solution space – for example, shadow pricing binding constraints, and mapping all state transition costs, evolutionary programming techniques explicitly solve the costs of a wide 'population' range of possible generation solutions as they evolve better solutions, and solutions that are only slightly more expensive than the least cost solution can be analysed through 'cost relaxation' as explained below. Thirdly, this study applies a range of techniques including clustering analysis to present this highly complex 'near optimal' generation mix solution space in more informative ways for electricity planners and policy makers.

The proposed approach is demonstrated in the particular context of the Indonesian Java-Bali interconnected power system. The Indonesian electricity industry context in terms of capacity generation profile, challenges, and current drivers, and supporting energy resources and potential were discussed in Chapter 2. Whilst reliability is a challenge and the environmental impacts of its coal dominated generation sector are also an issue, particularly if future developments focus on coal generation expansion, the government has developed a long-term plan that incorporates growing renewables yet has a continued reliance on coal (PLN, 2019). Whilst other groups have presented alternative visions for Indonesia's electricity industry future (IESR, 2019c), this study is intended to make a further contribution to the deliberations of Indonesian electricity industry planners and policy makers in an increasingly uncertain context of planning.

This study makes three new contributions to the body of knowledge around electricity industry planning, particularly to the energy modelling community's suite of methods and tools for exploring possible sustainable electricity industry futures. The study 1) explicitly maps the near-optimal solution space of generation mixes that perform nearly as well as the 'optimal' solution (and which may, of course, actually be better given future uncertainties); 2) explicitly categorises these high performing generation portfolios according to some key metrics for the energy trilemma; and 3) uses clustering to better understand the key performance trade-offs across these metrics. In summary, the innovation of this study is in the use of cost relaxation to get many reasonably low-cost solutions and then clustering techniques to identify key aspects of this range of solutions.

The rest of this chapter is organised as follows. The methods are outlined in Section 8.2 while Section 8.3 presents results and discussions from the case study of Indonesia's Java-Bali grid. Finally, concluding remarks for this chapter are presented in Section 8.4.

8.2 Methods

8.2.1 The methodological framework

This study develops a framework to assess possible future electricity generation portfolios given the multiple objectives of the energy trilemma and significant uncertainties, particularly related to future technology costs. The framework integrates two different methods. To incorporate uncertainty, multiple near least cost generation portfolios are collected from a stochastic optimisation model. To assess performance across multiple objectives, clustering is then used to examine the performance of the generation portfolios with respect to energy trilemma key metrics. The methodological framework is presented in Figure 8.1.

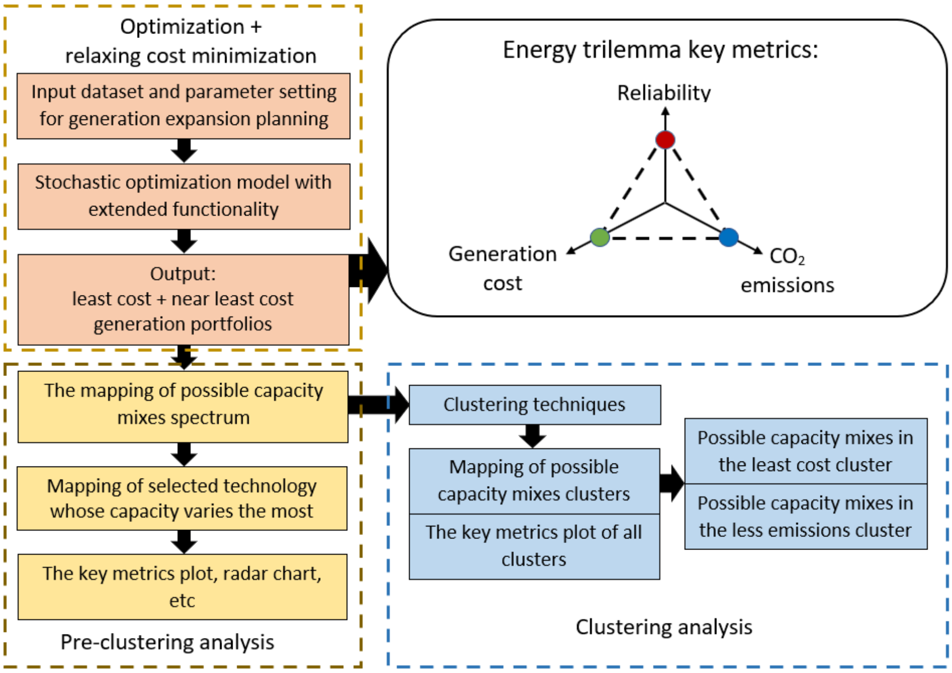


Figure 8.1: The framework for assessing possible future generation portfolios

8.2.2 Simulations, scenarios, and assumptions

This study applies the same database used in Chapters 6 and 7, particularly for techno-economic-emissions attributes of the generation technology candidates, dispatch order, hourly system demand, coal and gas costs, and solar and wind output traces. This study considers a fixed USE limit of 0.005% as a reliability constraint for the base case (i.e., for initially simulating least cost generation capacity mix) which is, arguably, a high reliability standard for the context of a developing country electricity industry. In this study, as shown in Figure 8.1 (upper left part), National Electricity Market Optimiser (NEMO) is adapted to produce a set of near least cost solutions by relaxing the cost constraint such that all generation portfolios with total generation cost within 5% of the least cost solution are retained. This study also applies carbon prices (CPs) of \$0/tCO_2 (CP0), \$30/tCO_2 (CP35) and \$60/tCO_2 (CP60), as also used in Chapter 7, to reflect possible future policy settings to achieve Indonesia's emissions reduction commitments, but also to capture some aspects of uncertainty around future coal and other fuel costs and costs associated with financing these increasingly risky projects. It should be noted that there is no specific carbon policy for the Java-Bali grid, however there is a government target of 23% RE share of generation mix by 2025 countrywide (MEMR, 2019). Similarly to Chapters 6 and 7, this chapter does not consider transmission network investment requirements.

The same assumptions as those applied in Chapters 6 and 7 are also incorporated into the model for this study, including a non-synchronous penetration ratio of 0.75, no minimum capacity reserves constraint, 5% discount rate on annualised technology capital cost, a conservative 5%

annual demand growth from 2015 to 2030, $3.5/GJ coal and $10.9/GJ gas prices, and up to 8 GW hydro and 10 GW geothermal capacity-built limit. The non-synchronous penetration ratio is limited to a maximum value of 0.75 mainly due to the consideration that the Java-Bali system at this transition stage, particularly in 2030, would still need other synchronous generators to provide sufficient flexibility and ramping capacities to accommodate hourly variability of VRE penetration. While minimum capacity reserves are usually considered in the generation planning studies, and hence it is included as one of the constraints in the simulations presented in Chapter 9, this chapter, as in Chapter 6 and 7, explores a range of possible solutions of generation mixes without capacity reserves to simply test and show that the system reliability requirement can potentially be fulfilled by the combination of high VRE penetrations and other renewables and fossil-based generation. Assumption on these parameters have been similarly adopted in (Simaremare et al., 2017). Given the low penetration of variable renewables in the Java-Bali grid, this study does not consider grid capacity to manage VRE, the impact of distributed energy, or energy storage technologies. This is aligned with, and allows the results to be compared with, the published planning documents for the Java-Bali electricity grid.

8.2.3 Clustering analysis and evaluation of clusters

Clustering analysis has been increasingly applied in some areas of the electricity industry, such as in studies around load profile identification and demand estimation incorporating different datasets, including load time series (Motlagh et al., 2019), smart metering data (McLoughlin et al., 2015), demand profiles (Roberts et al., 2019), (Rhodes et al., 2014), occupant activity data (Satre-Meloy et al., 2020), in addition to other applications covering smart energy systems (Meschede et al., 2019), and air-conditioning energy performance (Zhou et al., 2019). However, there is little literature relating to the application of clustering to electricity generation expansion planning. A recent clustering study in the area of capacity expansion planning is related to capturing the effect of variable renewables and energy storage (Scott et al., 2019), and time-period clustering for optimal capacity expansion planning with storage (Pineda and Morales, 2018).

Clustering techniques are applied in this study to map various possible solutions leading to secure-affordable-low emissions technology mixes. This study primarily applies a k-means clustering technique, considering its simplicity, efficiency, expandability, and ability to handle big data, and despite a few possible drawbacks, such as sensitivity to the initial selection of cluster centres and the possibility of producing a local optimum solution as mentioned in the studies of smart meter data (McLoughlin et al., 2015), demand profiles (Rhodes et al., 2014), and residential air conditioner control (Malik et al., 2019). The step-by-step working principle of k-means clustering, in which the solution space is divided or partitioned into several cells containing data points with similar patterns, is summarised in (Kotu and Deshpande, 2015). Neural network-based Self Organising Map (SOM) is then used to compare the clustering results. The overall SOM algorithm is summarised in (Mehrotra et al., 1997). Neural network based-SOM clustering has been applied, for example, in estimating load for microgrid planning (Llanos et al., 2017) and calculating load profile (Oprea and Bâra, 2016).

The optimal number of clusters in this study is evaluated according to the rules proposed in (Caliński and Harabasz, 1974) and (Davies and Bouldin, 1979). In principle, these methods work by applying two important criteria, i.e., cluster compactness and separation. The first criteria measure the closeness of the members of each cluster to reflect cluster compactness while the second criteria measure the distance between clusters to reflect separation among clusters. The optimum number of clusters according to the first rule is detailed in (Saitta et al., 2008), while the second rule measures the average of similarity between each cluster and its most similar one (Liu et al., 2010). To follow the evaluation criteria, a better number of clusters is represented by the lower-resulted index. Although there are some other evaluation rules available, the decision regarding number of clusters is eventually rather subjective depending upon the objective of analysis and details of the variability that users would expect.

8.2.4 Adoption of capacity mix parameters into energy trilemma

For each generation portfolio, the simulation of a year of operation provides three representative 'energy trilemma' metrics – achieved reliability (% USE), total industry costs - both capital and operating - ($/year) and carbon emissions (tCO_2). The last metric is used as a representative of the environmental impact since CO2 emissions represent the most significant long-term environmental risk. While coal-fired power plants, for example, release other greenhouse gasses such as methane and nitrous oxide, many official electricity generation planning statistics, reports and other literature use CO_2 emissions as an immediate representation of the air pollutants released by electricity generation and for its value in quantifying the impact to environment. In general, emissions of methane and nitrous oxide of these power plants account for only a minor proportion of the total emissions (Steen, 2001). These are not complete representations of the trilemma; industry costs in particular do not capture the complexities of equity and affordability (IEA, 2019c) while there are environmental impacts other than carbon emissions associated with different technology choices.

Although the USE constraint is set at 0.005%, this is an upper constraint and it is, of course, possible that candidate generation portfolios deliver lower USE. The conversion of the numerical values from actual achieved USE into a security score (magnitude) is, for simplicity, a linear interpolation from USE 0.000 to 0.005, equivalent to security scores from 100 to 75. Security scores between 75 and 100 are considered in this modelling exercise, given the relatively high constraint. This study conducts 2 steps of value conversion, normalisation, and a scaling procedure, to obtain the score for economic and environmental sustainability dimensions as follows:

(i) Sort candidate generation portfolios from the smallest to the largest value.

(ii) Determine the position (magnitude) of each value in the trilemma by normalising the sorted values according to the following equation:

$$Normalized\ value_i = 1 - \frac{Old\ value_i}{Old\ value_{max}} \tag{8.1}$$

(iii) Determine the scale of the normalised values. The minimum and maximum scale for economic and environmental sustainability dimensions are set to 25 and 100, respectively, for visual clarity in the presentation of results. This provides a scale range of 75. The scaling operation to obtain the new values within a certain range of old values is carried out using the following equations:

$$New\ value_i = \left[\frac{(Old\ value_i - Old\ value_{min}) \times New\ range}{Old\ range}\right] + Scale_{min} \tag{8.2}$$

$$Old\ range = Normalized\ value_{max} \tag{8.3}$$

$$New\ range = Scale_{max} - Scale_{min} \tag{8.4}$$

There is one further complexity in industry costs – the treatment of carbon costs. The role of carbon pricing is to change the relative competitiveness of different generation technologies by changing their operating costs according to their emissions intensity. While it is, of course, possible to then include these costs (price times total annual emissions) in total industry costs, they do actually represent carbon revenue (CR) that can go towards helping pay for other industry costs or reduce taxes elsewhere. This study, therefore, distinguishes between carbon costs and industry costs in some of the analyses. Analyses in this study are conducted according to the following steps:

There is one further complexity in industry costs – the treatment of carbon costs. The role of carbon pricing is to change the relative competitiveness of different generation technologies by changing their operating costs according to their emissions intensity. While it is, of course, possible to then include these costs (price times total annual emissions) in total industry costs, they do actually represent carbon revenue (CR) that can go towards helping pay for other industry costs or reduce taxes elsewhere. This study, therefore, distinguishes between carbon

costs and industry costs in some of the analyses. Analyses in this study are conducted according to the following steps:

(i) Relaxing cost minimisation: The set of candidate generation portfolios whose costs fall within 5% of the least cost solution for a predetermined 0.005% USE limit and each CP scenario are determined using NEMO.

(ii) Mapping candidate generation portfolios.

(iii) Pre-processing (pre-clustering analysis 1): This stage analyses candidate portfolios that have the highest and lowest PV capacity, together with the mixes with the highest and lowest coal capacity, the highest and lowest gas capacity, and the least cost mix. The three associated parameters of the mixes, i.e., cost, USE and CO_2 emissions, are then mapped and analysed as well. In this regard, the realised costs are analysed with CR component included and without CR component included.

(iv) Pre-processing (pre-clustering analysis 2): All associated parameters of the mixes (cost, reliability, emissions) are converted into 3 dimensions of energy trilemma and all values of the three dimensions are mapped for all seven portfolios (the highest and lowest PV, coal, gas and least cost portfolios) using radar charts. These charts depict the characteristics of different generation portfolios with respect to all dimensions of energy trilemma.

(v) Clustering analysis 1: The k-means clustering technique is applied to the 5% least cost technology mixes with different CPs to obtain groups of technology mixes. By using the k-means clustering algorithm in MATLAB, this study considers six clusters and 1,000 repetitions to obtain a stable clustering membership number and configuration for each carbon price scenario. For comparison, the SOM clustering technique is also applied, using nctool in MATLAB, and this produces very similar results compared to those obtained from k-means clustering. Applying the Caliński-Harabasz and Davies-Bouldin rules (briefly discussed earlier in Section 8.2.3) to evaluate the number of clusters to be used, the suggested number of clusters mostly falls between four and six. This study considers six clusters to better capture the variability of the associated parameters that possibly emerge from the analyses.

(vi) Clustering analysis 2: For each CP, the three associated parameters of each cluster are analysed using a boxplot, and cost and CO_2 emissions, as the two key parameters (given that the reliability level is within the expected range), are compared for all clusters. From this point, two distinct clusters can be identified, i.e., the cluster with least cost mix and the cluster with less emissions mixes.

8.3 Results and discussions

8.3.1 Base case results – least cost capacity and generation mix

This study first determines the least cost generation portfolios for the three different carbon price scenarios and the 0.005% USE limit. The simulations save all feasible generation portfolios during the search whose overall costs ($/year) fall within 5% of the eventual least cost solution. Note that NEMO can incorporate existing generation but undertakes what is effectively a single investment step – in this case for 2030 – rather than a sequence of investment steps.

Results for the 'least' cost generation portfolio with a 0.005% reliability constraint are shown in Figure 8.2 for the three CP scenarios. Note that there are constraints on maximum hydro and geothermal capacity, as proposed in (Tanoto et al., 2017). For CP0, there is substantial PV generation capacity in the least cost mix, but coal still predominates, with only a limited role for gas. CP35 sees more than double the PV but little other change in capacity. For CP60, PV capacity barely changes but wind generation now enters the mix, as does CCGT. Renewables climbs to over 70% of generation. These results might suggest certain choices and strategies for policy makers. However, the question arises of how sensitive they are to the specific 2030 cost assumptions, and what other generation mixes might offer relatively similar industry costs but perhaps quite different policy pathways.

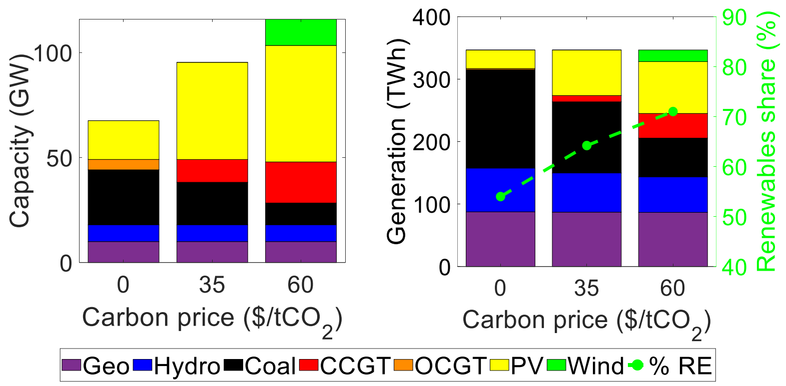


Figure 8.2: (left) Least cost capacity mix and (right) least cost generation mix with fixed 0.005% USE limit for all CPs

Results obtained for the case with no carbon price (CP0) are intended to reflect the latest single-scenario planning made by PLN (MEMR, 2019), in which no carbon price is considered, to provide a basis for comparison and as a baseline for policy development. This study, therefore, incorporates similar generation technology candidates to the published planning document. The results show that the renewables generation share by 2030 could achieve more than Indonesia's 23% renewables target (MEMR, 2019), with solar capacity within the technical potential for Indonesia (IRENA, 2017b), (Veldhuis and Reinders, 2013). This is in contrast to official planning, which shows only 18% share of RE, while least cost portfolios obtained in this study also show coal capacity less than that in the planning document (Figure 8.2).

By achieving about 55% RE share in the generation mix, notably including a high solar PV penetration as shown in Figure 8.2 (right), this study's least cost mix results in 146 mtCO_2, while the CO_2 emissions of the government's BAU projection for 2030 (for the Java-Bali region) would be around 397 mtCO_2. The targeted 29% reduction commitment would correspond to approximately 282 mtCO_2. The scenario presented in this study results in approximately 48% less emissions.

This highlights concern regarding Indonesia's pathways to de-carbonise the electricity industry in the future (Clark et al., 2020), and the role of coal. According to Indonesian government Regulation No. 79/2014 on National Energy Policy, the coal share in the primary energy supply mix should be a minimum of 30% in 2025 and a minimum of 25% in 2050 (MJHR, 2014). However, based on the results presented in this study, there is a promising opportunity to reduce emissions at low cost.

8.3.2 Fixed USE limit at 0.005%, cost relaxation up to 5% least cost technology mix

As the range of different least cost technology mixes is obtained, as presented in Figure 8.2 (left), each one of these three mixes is expanded into a spectrum of near least cost generation portfolios as shown in Figure 8.3. This spectrum of portfolios, for each carbon price, is obtained by relaxing the overall industry cost up to 5% of that of the least cost mix presented in Figure 8.2 and collating all generation portfolios that fall within this cost range.

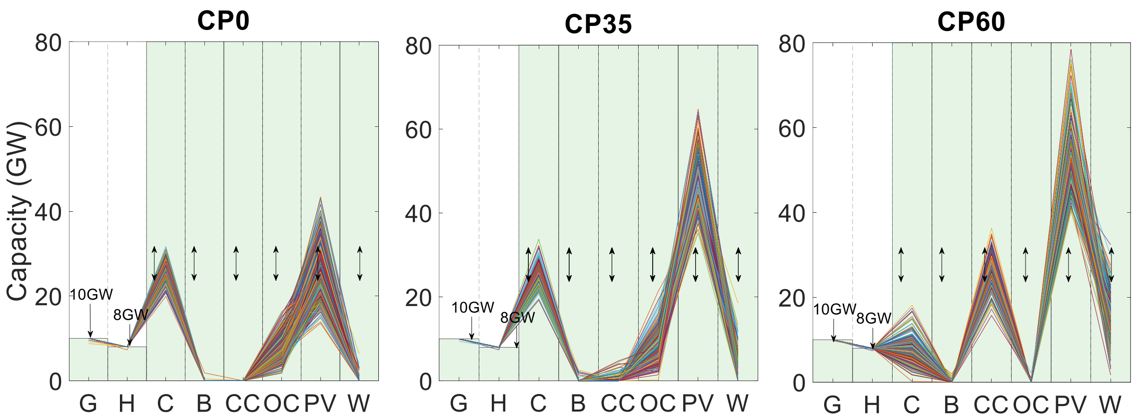


Figure 8.3: Possible technology mix by relaxing cost up to 5% least cost mix and by fixing USE limit at 0.005% for CP0 (left), CP35 (middle) and CP60 (right)

The spectrum of near least cost portfolios, for example at CP0, consists of some 600 technology mixes. A wide capacity range across coal, open cycle gas turbine (OCGT), solar and in some cases wind capacity is obtained. While geothermal and hydro capacity in 2030 remains at the maximum potential for all CPs up to 10 GW and 8 GW, indicated with a downside arrow, the simulations result in both smaller and greater capacities for other technologies, indicated with two-way arrows.

The spectrum of technology mixes highlights the potentially wide range of generation investment futures. At CP0, there are evident options for greater or lesser coal, more OCGT and much more or less PV. At CP35, the role of gas - now including combined cycle gas turbine (CCGT) - could be quite substantial, while the range of PV capacity increases and its range narrows. At CP60, coal capacity falls, CCGT climbs, PV capacity climbs further and wind becomes an option (from negligible to over 30 GW) across all candidate generation mixes. It is clear that the spectrum provides a richer set of insights for policy makers regarding their options and allows wider policy considerations to come into play – for example, concerns about future gas availability, or social acceptance of wind generation. However, it is less clear how these choices map to each other given that there are numerous candidate generation mixes presented, and choices in one technology capacity will, at least to some extent, dictate capacity choices in others.

8.3.3 Pre-clustering analysis

To better understand the trade-offs, selected candidate generation mixes, characterised according to those technologies whose capacity varies the most, are shown in Figure 8.4. For CP0, it is interesting to note that there is not a very strong trade-off between coal and PV capacity; indeed, the highest coal capacity mix actually has slightly more PV. The reverse also holds across the highest and lowest capacity of PV, which do not see great variation in coal capacity. The clearest trade-off would actually appear to be OCGT and PV. For CP60, by comparison, there is an evident trade-off between coal and CCGT generation, as well as with PV generation.

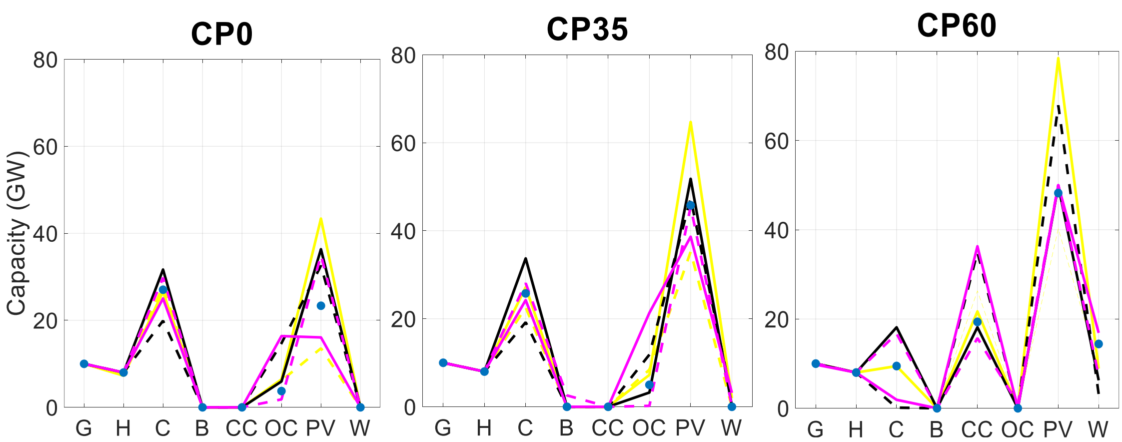


Figure 8.4: Generation mixes with the highest and lowest possible capacity of PV, coal, and gas, as well as the least cost mix, for each CP scenario

These highest and lowest generation mixes for each key technology within 5% of least cost are further investigated in terms of emissions and USE in Figure 8.5. For CP0, it is notable that the lowest cost mix has the highest USE, and higher emissions than all except the L-PV and H-OCGT cases. It appears that for around $400m/year it would be possible to reduce emissions by around 20 mtCO_2/year by deploying more PV. For CP35, the H-PV mix has mid-range costs yet the lowest emissions and USE. For CP60, the least cost mix is considerably lower cost than the other options and has mid-range emissions (they are of course priced at $60/t$CO_2$) but lower reliability than all the other options. Excluding the CR from total industry costs, on the basis that this money can be used to compensate energy consumers, has interesting implications in making the higher emission H-coal mix more attractive. When CR is excluded from industry costs, it is also interesting to note that CP35 makes the least cost mix only around $200m/year more expensive, yet reduces emissions by over 25 mtCO_2/year, which would seem to represent relatively low-cost abatement. CP60 costs around $2.4b/year but reduces emissions by around 75 mtCO_2/year, considerably higher cost abatement. These outcomes for the min-max technology mixes can also be characterised using the trilemma indicators outlined earlier, and then plotted with radar diagrams as presented in Figure 8.6.

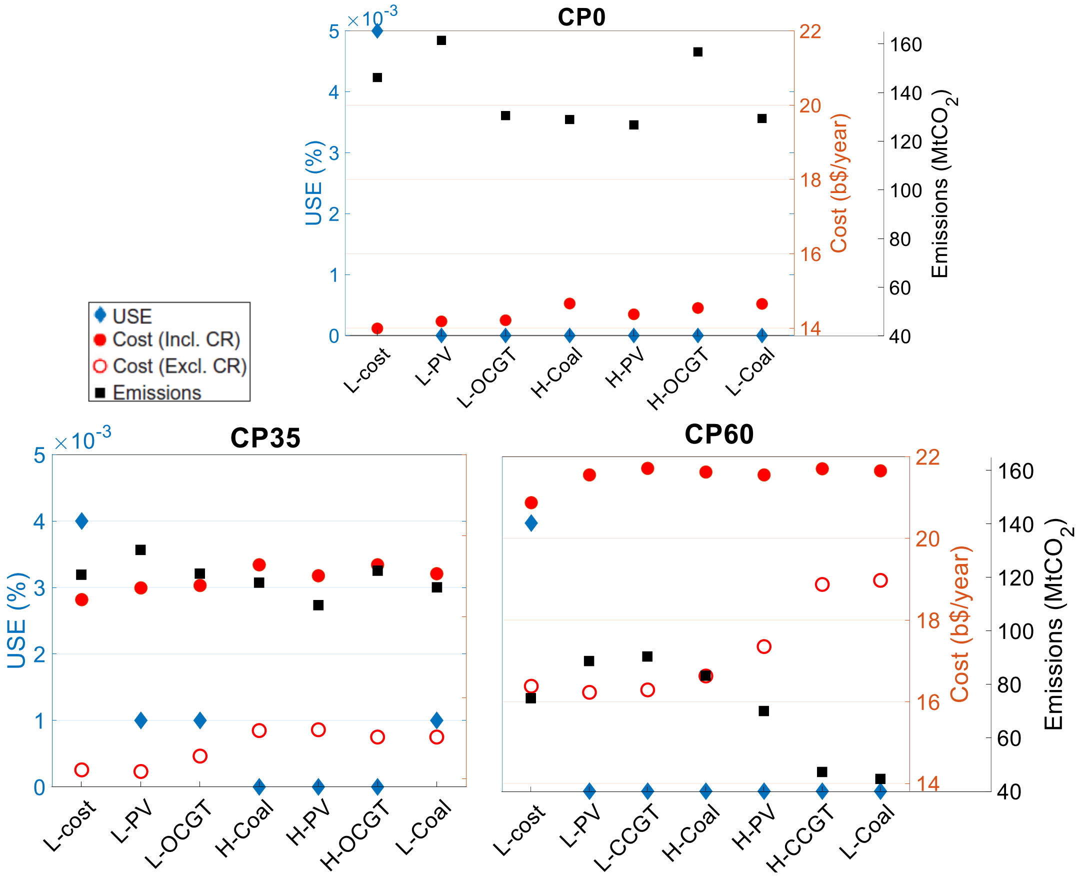


Figure 8.5: The mapping of USE, total cost, and CO_2 emissions of generation mixes with the highest and lowest capacity of PV, coal, and gas, as well as the least cost mix for the three CP scenarios

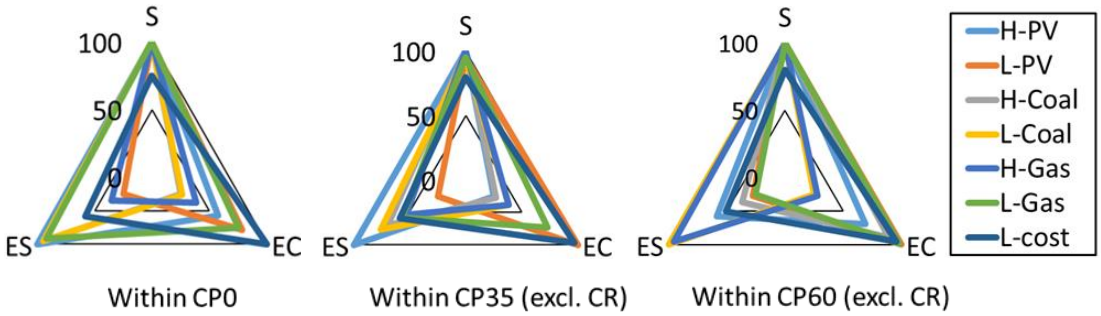


Figure 8.6: Radar charts of security (S), economic (EC) and environmental sustainability (ES) dimensions for each min-max technology (economic indicator is calculated excluding CP revenues from industry costs)

Note that these plots use industry costs excluding carbon price revenue, as this could be argued to involve double counting of the environmental impacts. Also, as noted above, the security metric for all these candidate generation mixes only varies between 75 and 100 reflecting the very low USE seen in all cases.

These radar diagrams nicely illustrate the trade-offs involved between choosing particular min-max technology mixes. There are no clearly superior candidate generation mixes across all the trilemma dimensions. However, there are a number of candidate mixes which would seem to have secure-affordable-low emissions alternatives – for example, the L-OCGT (L-Gas) mix in CP0 and CP35 and the L-cost in CP60.

8.3.4 Results on clustering analysis

Consideration of the min-max technology deployment mixes is useful in bracketing the possible variation in mixes whose costs fall within 5% of the least-cost mix. However, to better characterise the solution space, k-means clustering is used to group all solutions into six clusters. Figure 8.7 (left) shows six capacity clusters for CP0 case.

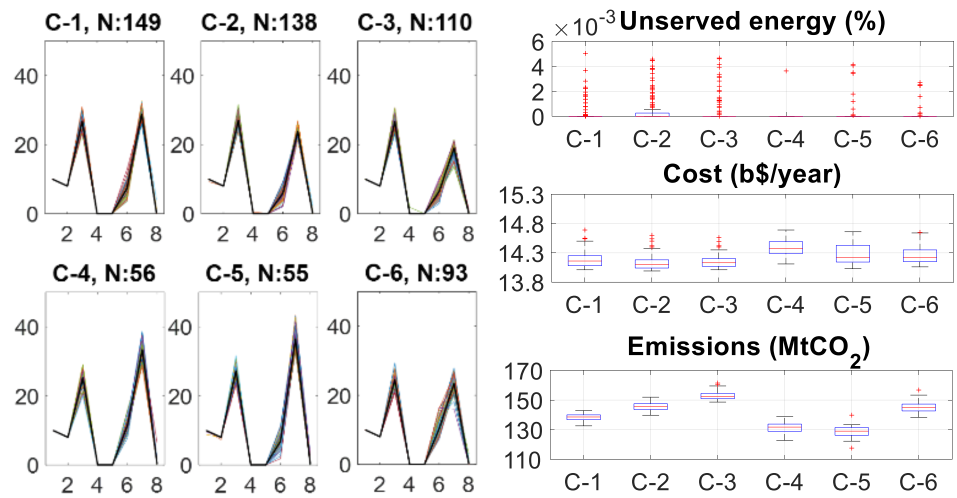


Figure 8.7: (Left) Six capacity clusters (y-axis = GW of capacity for each available generation option along the x-axis) and (right) unserved energy, cost, and CO_2 emissions of all clusters CP0

The y-axis scale limits are made equal for all clusters to enable quick visual comparison of clustering patterns. The mean capacity mix for each cluster is shown using a black colour line to help identify the spread of each of the clustering patterns.

As shown in Figure 8.7 (left), all clusters are characterised with little variations in coal capacity yet considerably more in PV. Higher capacity mixes of PV are clustered together in cluster 5 with a wide range of OCGT. This differentiates cluster 5 from cluster 4, despite both clusters having a similar pattern as seen from their mean capacity. Capacity clusters are further identified based on their USE, cost and CO_2 emissions, and the range of these are shown, and can be compared, in Figure 8.7 (right). Cluster 2 has the lowest average cost. However, cluster 1, which has a similar range of costs to cluster 2, has a lower range of CO_2 emissions. The range of generation capacities in these two clusters is shown in Figure 8.8. It is interesting to note that a modest increase in costs allows greater PV and OCGT deployment.

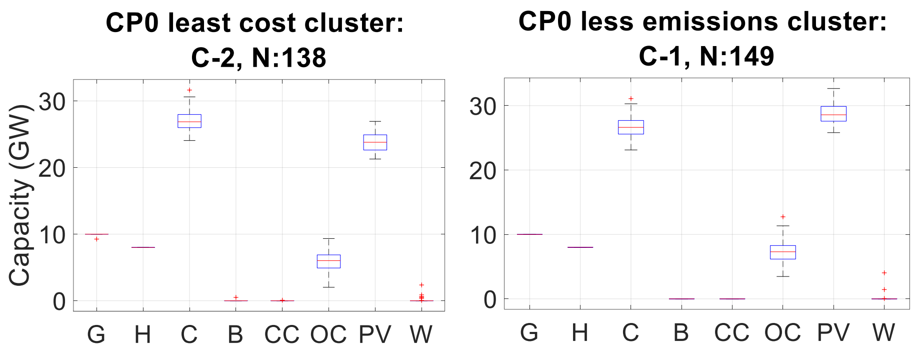


Figure 8.8: (Left) Generation technology mixes in the least cost cluster (C-2) and 'less emissions' cluster (C-1) for 5% least cost capacity mix with CP0

Using the same analysis approach, clustering results of the technology mixes in CP35 and CP60, along with the results for least cost mix cluster and less emissions cluster identification, are presented in Figure 8.9 to Figure 8.12.

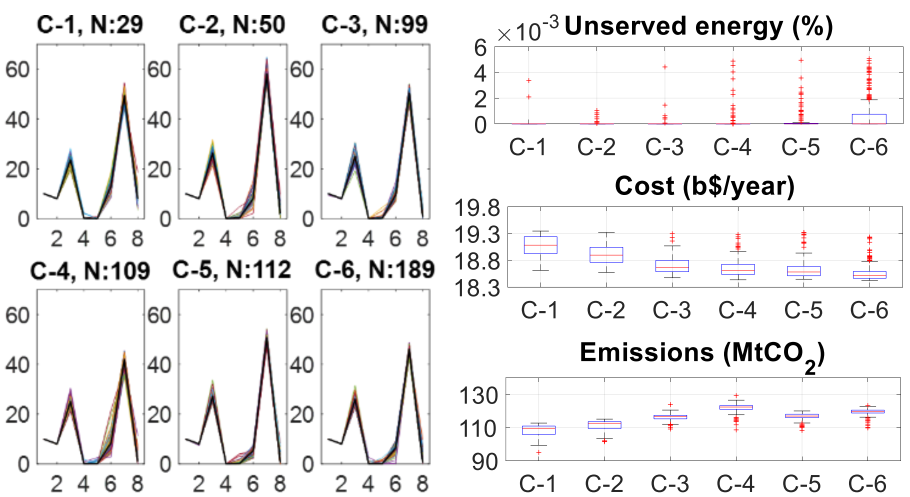


Figure 8.9: (Left) Six capacity clusters (y-axis = GW of capacity for each available generation option along the x-axis) and (right) unserved energy, cost and CO_2 emissions of all clusters CP35

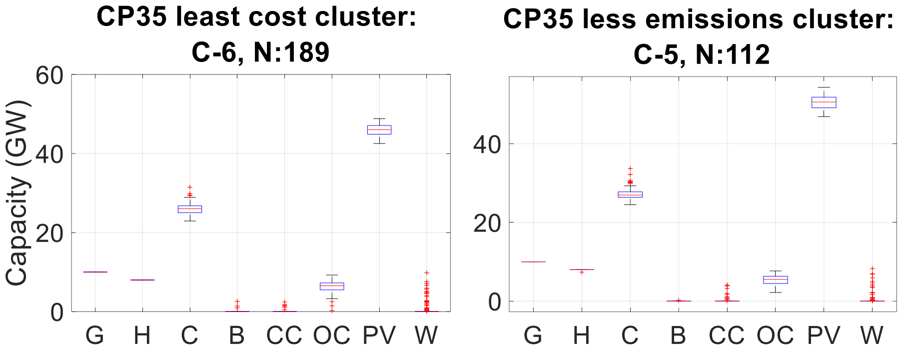


Figure 8.10: (Left) Technology mixes in the least cost cluster (C-6) and (right) technology mixes in the 'lower' emissions cluster (C-5) for 5% least cost portfolios with CP35

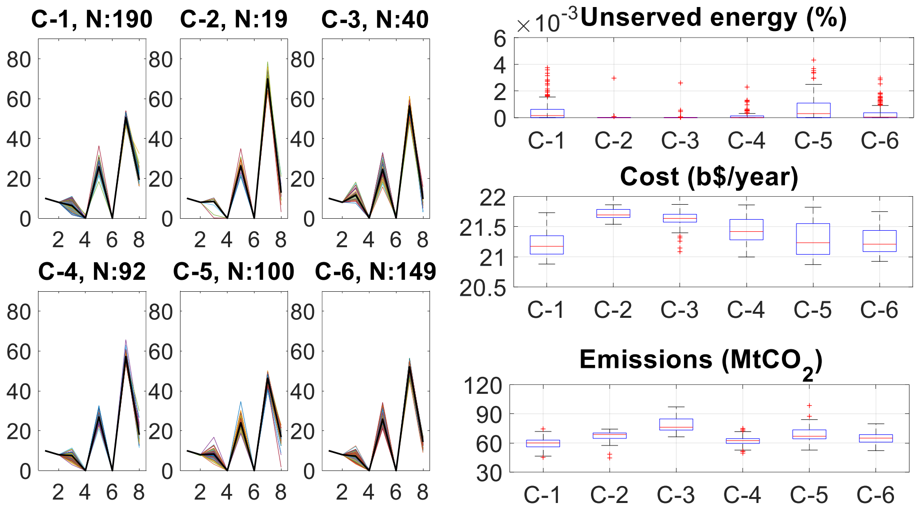


Figure 8.11: (Left) Six capacity clusters (y-axis = GW of capacity for each available generation option along the x-axis) and (right) unserved energy, cost and CO_2 emissions of all clusters CP60

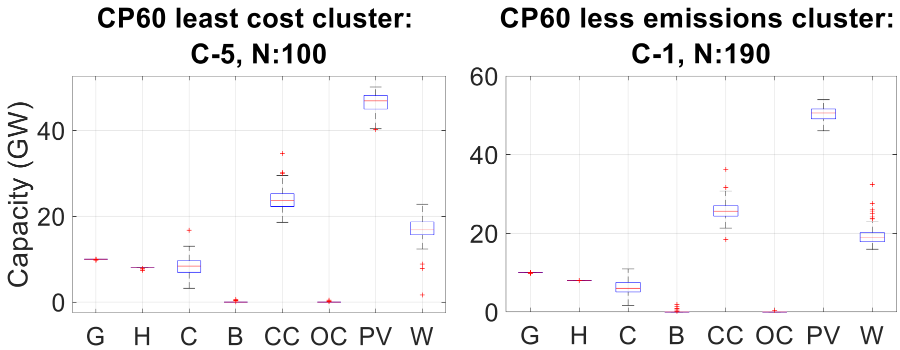


Figure 8.12: (Left) Technology mixes in the least cost cluster (C-5) and (right) technology mixes in the 'lower' emissions cluster (C-1) for 5% least cost portfolios with CP60 and fixed 0.005% USE limit

While keeping the coal capacity range remain unchanged or with only small, insignificant variations, as shown in Figure 8.8 (right), Figure 8.10 (right) and Figure 8.12 (right), higher PV capacities are deployed in all technology mixes in the less emissions cluster than in the least cost clusters, for all CPs. This increased PV deployment, and hence reduced emissions, comes at what would seem to be fairly low additional costs. The spread of the emissions and costs in the clusters also offers potentially valuable insights for policy makers into the impacts, in terms of cost or emission risks, that might be arise from strategies to drive particular technology deployment patterns.

8.3.5 Shared area of possible technology mixes

A method to compare possible technology mixes for each of the CP scenarios in Figure 8.3 is presented in Figure 8.13. This visualisation provides a way to see the possible range of capacity deployment of each generation technology, and gain insights into the possible capacity trade-offs across both conventional and variable renewables. It is interesting to note that the range of coal generation capacities in for CP0 and CP35 overlap almost entirely, despite more solar PV and wind capacity in CP35. A higher total generation cost in CP35 than in CP0 results from more capacity built, although coal fuel costs are reduced. CP60, by comparison, has low coal capacity and, a very different pattern of CCGT deployment, while seeing almost no OCGT deployed. This reflects of course the higher emissions intensity but lower capital costs of OCGT versus CCGT.

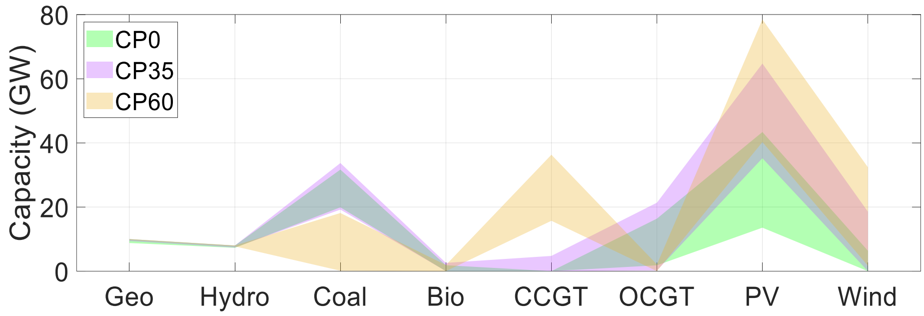


Figure 8.13: Overlapping areas of the possible technology mixes of all CPs and its intersections

A higher CP increases the competitiveness of CCGT, even for low-capacity factor operation. The results indicate that if a relatively high social cost of carbon is considered, policy should be directed to deploy large-scale variable renewables penetrations, particularly solar PV. The results also indicate that limiting Java-Bali future coal capacity, in this case to less than 40 GW, it is a low-cost option either with or without consideration of the cost of carbon.

Similar results in terms of the impacts of CP on the capacity of CCGT, nevertheless, may or may not be necessarily identified in other electricity industries in ASEAN-5 countries. While electricity from gas-based generation mainly depends on the gas price, coal price fluctuations might also give important impacts on the changes of gas price and demand for the industry, and thus the competitiveness of CCGT.

8.4 Conclusions

Electricity industry planning for a more sustainable energy future is enormously challenging given the potentially conflicting objectives of affordability, security and environmental impacts, and the very high levels of future uncertainty regarding their prioritisation, as well as in generation technology progress and costs. Developing countries face challenges in all these regards. While there is a wide and growing range of simulation and optimisation tools to assist in such planning, they have inevitable limitations in terms of incorporating these uncertainties and mapping trade-offs.

This study sought to advance existing tools and methods in three keyways – identifying explicit metrics of the energy trilemma that could be used to assess different possible future electricity industry generation portfolios across all key dimensions, mapping the solution space of 'high performing' if not absolutely 'least cost' generation portfolios including through the application of clustering, and exploring ways to present the solution space to planners and policy makers. The study applied this to the question of possible future generation investment pathways for the Java-Bali interconnected system. Techniques applied in this study highlight the very diverse generation portfolios that delivered costs close to the 'least cost' portfolio. Given the uncertainties involved in these cost estimations, notably future technology and fuel costs, it is clear that policy makers and planners have a wide range of possible pathways towards a more sustainable electricity industry future. There are important trade-offs, particularly between costs and emissions, in these choices. These techniques, as well as these findings, would seem to have wider relevance to the electricity industry planning and policymaking communities, especially in assisting them unveiling a wide range of possible generation portfolios that are suitable to their preference pathways and electricity industries' context, given the techno-economic potential of high variable RE penetrations.

This study has used some similar basic settings and assumptions for the simulations as in Chapter 6 and 7, such as the hourly demand, and VRE output traces, among others. While the default case, under 0.005% USE, has exhibited similar generation capacity mix to that obtained in the previous chapters, i.e., for the least cost solution without CP, the modelling research applied in this study has outlined the wide spectrum of technology mixes and clustered possible solutions according to the key sustainability objectives trade-offs, highlighting the potentially wide range of generation investment futures that can deliver far more sustainable industry outcomes.

Given the range of potential generation portfolio options that could improve system reliability and offer a better environmental outcome at low cost, the analyses highlight the importance for policy makers in developing countries to consider a range of options to satisfy the trilemma objectives. This is particularly important given the uncertainties around future technology costs. While imposing a carbon tax on the supply side would be expected to increase electricity costs, the analyses show that a faster shift to high penetration renewables could, in fact, be relatively low cost and therefore improve access and affordability with lower risk around the future costs of emissions and fossil fuels.

As the techniques presented here could be applied to a broader range of electricity industry planning problems where multiple objectives are to be satisfied, future work could seek to address some of the limitations of the existing modelling framework, including adding transmission costs and a greater role for different storage technologies, and to use more nuanced, weighted metrics of the trilemma. Other future work (see Chapter 9) could also explore the extension of potential benefits of deploying high VRE penetrations, i.e., from improving supply reliability to enhancing system security.

Chapter 9
System Dynamic Operating Reserves in Future Optimum Electricity Generations Portfolios with High Variable Renewable Penetrations and Different Reliability Targets

This chapter is based on a conference paper presented at the 2019 International Conference on Environment and Electrical Engineering (EEEIC), Genoa, Italy and published in IEEEXplore, and later extended into a journal paper published in The Electricity Journal (Elsevier) under the title "Impact of high solar and wind penetrations and different reliability targets on dynamic operating reserves in electricity generation expansion planning". The thesis author is first author of the article, having performed study design, implementation, and primary drafting, with co-authorship also from A/Prof Iain MacGill, Dr. Anna Bruce and Dr. Navid Haghdadi based on supervision, review, and editing.

This chapter presents the extension of potential benefit of deploying high variable renewable energy penetrations from improving supply reliability to enhancing system security. This study presents a method for assessing system dynamic operating reserves in long-term electricity industry planning in emerging economies using high-temporal (1-hour) resolution demand and wind and solar profiles. The method is applied through a case study of Indonesia's Java-Bali grid, considering future scenarios both with and without variable renewables, under different carbon pricing scenarios, reliability targets, and minimum reserves requirements.

9.1 Introduction

Solar photovoltaic (PV) and wind generation technologies are increasingly cost-competitive alternatives to the conventional, carbon emission-intensive, fossil-fuel coal and gas generation technologies that currently dominate the generation mix of most jurisdictions. Therefore, these technologies are playing a key role in the low-carbon electricity industry transition around the world. Nevertheless, growing penetrations of these highly variable renewable energy (VRE) technologies also raise security and reliability questions for electricity industry planners and policymakers (Kroposki, 2017), (IEA, 2017a), and form the motivation for the study presented here.

Early deployment of utility-scale PV and wind largely occurred in the electricity industries of OECD countries, and they now offer examples of successful integration at relatively high penetrations. However, VRE also shows great promise for the electricity sectors of emerging economies to address their affordability and environmental challenges. As reviewed earlier in Chapter 3 (see Section 3.1.1 and 3.1.2) and in studies reviewed in Chapter 7 and 8, solar and wind penetrations are climbing rapidly in many jurisdictions and are now being widely incorporated into electricity planning studies across the developing world.

While solar PV and wind costs continue to fall, their highly variable and somewhat unpredictable output does raise several challenges for secure and reliable power system operation. In particular, the need for sufficient generation capacity to meet demand at all times and locations, including periods of low PV and wind availability, means that even major VRE deployment still requires significant levels of highly dispatchable generation (Monyei et al., 2019), which is conventionally provided by coal, gas, or hydro plant. Of course, these conventional generation options are also subject to occasional plant failures, and there are other possible risks to availability including fuel supply interruptions, droughts, extreme weather events, and natural disasters (Gülen and Bellman, 2015). Power systems therefore typically maintain some level of generation operating reserves to cover periods where even generally highly dispatchable plants might prove unavailable.

Wind and solar generation pose some difficulties for establishing appropriate levels of operating reserves given the highly complex and somewhat uncertain availability of the wind and solar resource looking forward in time (Dorsey-Palmateer, 2019), particularly if and as their penetrations climb. However, they also offer some advantages as they are typically deployed in a highly modular fashion comprising parallel strings of PV modules and inverters for solar farms and tens to hundreds of MW scale turbines for wind farms. As such, they do not tend to have the single points of failure that are present with large thermal plant units. Furthermore, periods of high wind and/or solar may represent times where the unexpected failure of some generation, renewable or conventional, can be more easily managed due to excess online generating capacity. Understanding operational uncertainty of the power system with high solar and wind penetrations is therefore one of the key factors for planners and utilities in ensuring the system meets reliability criteria (Go et al., 2020), including the level of reserves.

An additional complexity is the question of what level of reliability might be reasonably expected given the costs associated with higher reliability targets, regardless of the generation mix. This question is particularly vexed for the electricity industries of emerging economies where achieved reliability is often considerably lower than for developed economies, for a range of reasons that extend beyond insufficient operating reserves, and where increased industry costs must be carefully balanced against affordability concerns.

An early key study established that wind variability and uncertainty need not be treated as a potential contingency, yet also highlighted the challenges of securing sufficient operating reserves at times of high demand and low wind (Holttinen et al., 2012). (Vos and Driesen, 2014) suggested that reserves should be dynamically calculated with ongoing economic/market dispatch, depending on the level of variable generation, rather than statically fixing reserve capacity for extended periods, with the risk of over-estimating these needs. Possible reductions to conventional operating reserve requirements and hence generation cost savings were assessed using a probabilistic approach to forecasting wind power. (Krad et al., 2017) also argued for dynamic rather than static operating reserve requirements, including ramping reserves, to improve reliability and economic outcomes as renewable penetrations grow.

Meanwhile, the value of geographical dispersion of utility renewables to smooth reserve requirements is highlighted in (Choukri et al., 2018). However, in this study, wind generation estimates were produced by scaling up linearly from 12% to 100%, which does not account for spatial smoothing (Choukri et al., 2018). An international comparison of how different jurisdictions incorporate wind generation into their process for setting operating reserves is presented in (Milligan et al., 2010), which found that most jurisdictions apply a statistical approach such as Monte Carlo simulations, to handle wind variability when establishing regulating reserves, while some use methods like scenario analyses, and less than half of jurisdictions surveyed considered ramping reserve type in their integration studies. Of relevance to this paper, (Vos and Driesen, 2015) used a unit commitment model to show the potential of wind as a downward operating reserve provider, and the impact on system scheduling and generation costs. (Vos et al., 2019) presented dynamic sizing methods, including machine learning methods, for determining the required sizing of frequency restoration reserve during risk periods due to increasing renewable generation.

This chapter seeks to address some key gaps in work around operating reserves and high VRE penetrations to date. These key gaps include: (i) detailed assessment of the opportunity for possible future high solar and wind penetrations and their impact on dynamic operating reserves, (ii) the implications of high PV rather than wind penetrations for these reserves, and (iii) the use of real-world high temporal resolution (hourly) wind, PV, and demand data over the one-year time frame commonly used for assessing operating reserves within electricity generation planning.

This chapter presents very high VRE penetrations, particularly solar PV, in future generation scenarios and quantifies the opportunities that these penetrations might offer to improve the reliability and security of the grid, due to the extra dispatchable generation capacity required for those few periods of very low wind and solar availability.

The chapter introduces a novel approach for presenting operating reserves, based on plotting dynamic operating reserves against Load Duration Curves (LDC) over a typical year of operation. The impact of different reliability standards on the magnitude of dynamic operating reserves is also assessed in this study. This question is particularly relevant to the electricity sector in emerging economies where achieved levels of reliability are far lower than for developed economies for a range of reasons, and hence where very exacting reliability standards in generation capacity planning might not always be appropriate.

As in Chapters 6 to 8, this study also uses NEMO (Elliston et al., 2013), which solves a full year operational dispatch of generation capacity optimisation for all candidate solutions using an evolutionary programming algorithm, applied to the case study of the Java-Bali grid in Indonesia. Future least-cost generation mixes are solved for a range of scenarios including ones that exclude as well as permit VRE, apply different levels of carbon pricing, and set different minimum operating reserve requirements. For each scenario, this study assesses the impact of different least-cost generation mixes on dynamic operating reserve levels, total industry generation costs, and CO_2 emissions.

This chapter presents wider implications of different reliability requirements, as measured by Unserved Energy (USE) targets, on dynamic reserves, rather than just applying a single, reasonably stringent target, as previously studied in (Tanoto et al., 2019). This study is the first to explicitly model possible futures for the Java-Bali grid that include high wind and PV penetrations and assess operating reserves, total industry costs, and emissions, over a yearly time horizon at a range of reliability standard levels. However, more broadly, the methods presented here apply to sustainable electricity industry planning in the growing number of jurisdictions considering possible future electricity sector development pathways with high solar and wind penetrations.

The rest of this chapter is organised as follows. Section 9.2 presents the methods used for this study. Section 9.3 presents and elaborates the results obtained from the analysis of a range of possible future scenarios for the Java-Bali grid, and their broader implications are discussed. Finally, Section 9.4 provides some concluding discussion of the findings and potential future work.

9.2 Methods

9.2.1 NEMO modelling, simulation, and optimisation overview

As mentioned in Section 9.1, this study uses NEMO, a stochastic open-source chronological dispatch model to firstly solve optimum generation capacity mixes (see Section 6.2.2). The way NEMO conducts simulation and optimisation, i.e., how inputs and constraints in NEMO interact to produce output, is depicted on its optimisation framework (see Section 6.2.2, Figure 1). NEMO outputs include the least cost dispatch of the solution generation mix over the study period, allowing investigation of system operation including ramping rates, plant starts and stops and, key to this study, available generation capacity in excess of demand per time period.

Key NEMO settings beyond the evolutionary optimisation parameters are the minimum reliability required in the solution – defined as the allowed % unserved energy (USE) and minimum reserve levels. Rather than using hard constraints, NEMO can also incorporate reliability, security, and environmental objectives through the cost function – e.g., carbon pricing emissions from fossil fuel generation. The carbon prices (CPs) are also incorporated in studies presented in Chapters 7 and 8 of this thesis.

9.2.2 Assessment of dynamic operating reserves

There are some complexities and choices in classifying different types of generation capacity reserves for power system planning (Dubitsky and Rykova, 2015) as well as different sizing methods for estimating operating reserves (Vos et al., 2019). While approaches for estimating operating reserves are often differentiated according to the nature and timing of reserve availability, this study does not attempt to categorise hot and cold reserves or any demand-side opportunities in the modelling. Instead, this study focuses on the impact of least-cost generation mixes with high VRE penetrations on the dynamic system operating reserves at an hourly resolution over a future simulated year of power system operation.

These system dynamic operating reserves are calculated according to the level of undispatched dispatchable fossil-fuel plants and any curtailed 'surplus' energy generated by VRE each hour. Given its very low operating costs, available VRE generation is dispatched by the model before any-fossil fuel generation is called upon. That displaced dispatchable generation is then available as reserves if and as required. When there is sufficient VRE to entirely meet demand and it is being curtailed, then this provides even greater reserves. Hence, hourly system operating reserves are calculated as (Tanoto et al., 2019):

$$Sys\_res_h = Undispatched\_disp\_res_h + VRE\_spill_h \quad (9.1)$$

where Sys_res_h is the system operating reserves in hour h, $Undispatched\_disp\_res_h$ is those reserves obtained from undispatched conventional plants in hour h, and VRE_spill_h is any surplus VRE during hour h.

A plot of dynamic reserves can be created by sorting a year of power system operation into an LDC from highest to lowest hourly demand and then plotting the actual operating reserves for each of those hours. Given the potentially considerable hour to hour variability in such operating reserves, this study uses a moving average (2 day) windows to better show the trend in dynamic reserves.

9.2.3 Case study – The Indonesia's Java-Bali grid

The general context and profile of the Indonesian electricity industry and Java-Bali grid are broadly discussed in Chapter 2 (see Section 2.3). The discussion highlights the Java-Bali grid as a useful case study as the region has an excellent solar resource as well as abundant coal-fired generation potential, while facing growing environmental, affordability and reliability challenges as electricity demand continues to grow.

Improving system reliability is one of the Indonesian electricity sector's major challenges, including in the Java-Bali grid. PLN's grid planning studies generally set the required operating reserves at 30% of the system's peak load (PLN, 2018). However, in practice, actual system reserves have been observed mostly less than this, particularly during high demand periods, with consequent reliability and security risks.

The Java-Bali outage in August 2019 was triggered by multiple gas turbines failures and impacted Indonesia's capital and its neighbouring cities (Adamczyk, 2019). It has heightened PLN and energy policymaker's concerns regarding the potential limitations of relying on fossil-fuel-based generation and seasonally affected hydropower plants to provide sufficient system reserves to cover unexpected generating unit failures and other possible disturbances. More generally, many regions of Indonesia still face relatively poor standards of electricity service reliability, often due to network-related issues.

Therefore, it is important to examine reasonable levels of reliability to target at a system-level given this reality and given the costs of having higher reserves. This challenging context motivates this study into how future high wind and solar penetrations might impact on operating reserves under a range of reliability targets.

9.2.3.1 Future Java-Bali Grid Scenarios

NEMO optimisations for this study were carried out to solve the least-cost 'greenfield' (i.e., all new build) generation mixes for reliably meeting projected 2030 Java-Bali grid demand – providing a 'least-cost' capacity and generation mix of the available technologies, overall annualised total industry generation costs (including both operating and investment costs) and expected total annual industry CO_2 emissions.

The scenarios considered include the case where solar and wind are, or are not available, where three possible future carbon prices (CPs) similarly to those in Chapter 7 and Chapter 8, are applied - \$0/tCO_2 (CP0), \$30/tCO_2 (CP30) and \$60/tCO_2 (CP60) - and where minimum operating reserve levels are set at zero or 30% of peak demand.

A key feature of the NEMO optimisation is the ability to set a reliability target for this 'least cost' generation mix. This reflects the planning reality that the costs of ensuring all demand are always met can be considerable, and some small level of USE is generally acceptable. In addition to a fixed 0.005% upper USE limit reflecting a very high-reliability requirement, this study also explores the implications of 0.5% and 1% up to 5% USE limits in all simulations without reserve constraints. Thus, this study assesses the implications of different reliability standards on least-cost generation capacity mixes, overall industry costs and CO_2 emissions, and more importantly dynamic operating reserves.

As in Chapters 6 to 8, this study also applies actual 2015 hourly demand – to capture daily and seasonal demand variability and uncertainty – of the PLN's Java-Bali electricity grid as a baseline for modelling the 2030 demand profile based on an annual (PLN would argue conservative) growth of 5%.

9.2.3.2 Renewable energy generation potential

As in earlier chapters, this study models Java-Bali wind and solar potential using data from Renewables Ninja, and NEMO is provided with a normalised PV generation profile over the year 2015 for six different sites across the Java-Bali region, one in each province, following a methodology used in (Tanoto et al., 2017) and in (Simaremare et al., 2017). Similarly to earlier chapters, this study chooses not to limit the maximum capacity of either wind or solar in the NEMO optimisation, given the still very high uncertainty regarding the underlying wind and solar resources across the Java-Bali region, despite some studies having made fairly conservative estimates of the potential total installed capacity for each technology (Veldhuis and Reinders, 2013), (NREEC, 2017), (IRENA, 2017b). For geothermal and hydro generations, this study also constrained the total potential capacity of each to a maximum of 10 GW and 8 GW, as in previous chapters.

9.2.3.3 Fuel and technology costs

As in Chapters 7 and 8, this study assesses least-cost generation capacity mixes drawn from a broad range of fossil fuel and renewable generation technology candidates - geothermal, hydropower, coal-fired steam cycle, Open Cycle Gas Turbine (OCGT), Combined Cycle Gas Turbine (CCGT), biomass combustion, as well as of course, solar PV fixed axis plant and onshore wind farms. This study uses the same discount rate on annualised technology capital costs, coal and gas price, and mid-level 2030 technology costs as applied in earlier chapters.

9.3 Results and discussions

The simulation results in terms of 2030 electricity generation mix in the Java-Bali grid, with or without a reserves constraint, are categorised into two groups, (i) with large-scale VRE integration, and (ii) without VRE. The simulation results for the least cost mix without VRE consist of coal, OCGT, hydro and geothermal, and are similar to that planned by PLN in the latest 10-year plan of 2019-2028, which contains neither wind nor solar PV, whereas the least-cost mix with VRE comprises coal, CCGT, hydro, geothermal, solar PV and wind. The total generation cost and CO_2 emissions due to the presence or absence of large-scale VRE in the system can be compared from these results.

9.3.1 Simulation without reserves constraint and with 0.005% upper USE limit

In the case of no reserves constraints and a minimum 0.005% USE requirement, wind and solar both reduce total industry costs as well as CO_2 emissions, even in the absence of a CP. Setting a CP delivers even greater industry cost and emission reductions, as shown in Figure 9.1. The generation technology capacity mixes for these least-cost mixes both with and without VRE are shown in Figure 9.2.

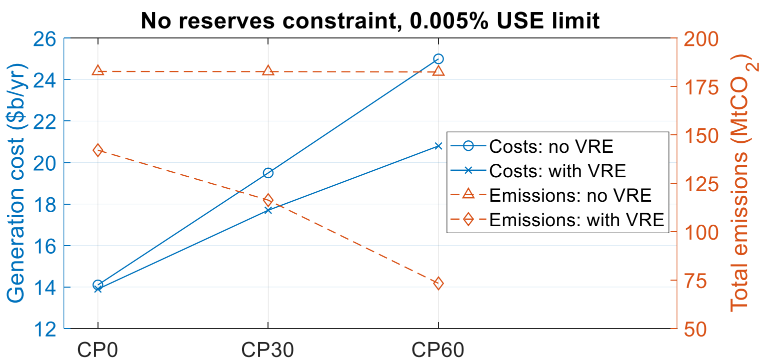


Figure 9.1: Total industry costs and CO_2 emissions of the least-cost generation mixes with 0.005% upper USE limit and no reserves constraint

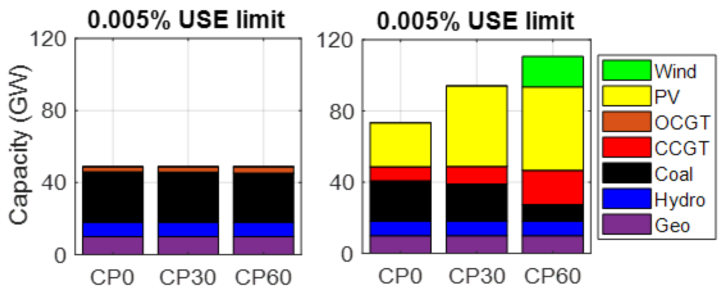


Figure 9.2: Least-cost capacity mixes for all CPs at 0.005% USE limit without reserves constraint, (left) without VRE and (right) with VRE

It is perhaps surprising that the CP has a remarkably limited impact on the least cost capacity mixes, or on total industry CO_2 emissions, when VRE is unavailable. This is a result of the high assumed cost of gas in 2030 compared with coal which means there is a little substitution of coal with lower emission gas-fired generation, even at CP60.

The higher costs in this scenario represent the impact of a carbon 'tax' on generation and note also that this 'tax' represents revenue which could be used to compensate energy users for higher costs. Hence, caution is required when presenting total industry costs in the presence of a CP.

In the least cost generation mixes with VRE available, the key reason for lower industry generation costs in the CP0 scenario is reduced coal operation due to the presence of PV, and higher efficiency CCGT replacing some coal and OCGT capacity. For the CP30 and CP60 scenarios, the increasing total costs of the generation mixes is an outcome of both the capital costs of more PV plant capacity (and, for CP60, also wind capacity), with far less reduction in coal capacity, as well as the carbon tax imposed on industry CO_2 emissions.

Figure 9.3 shows cases of operating reserve duration curves resulting from NEMO optimisations with and without VRE, ordered according to the corresponding estimated 2030 Java-Bali LDC.

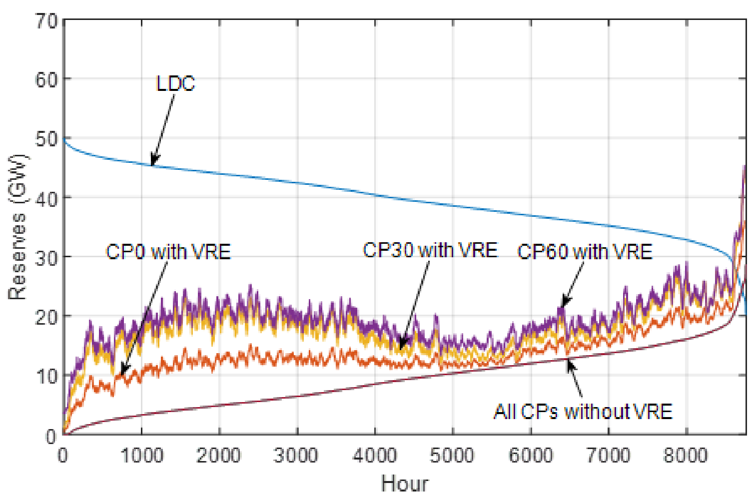


Figure 9.3: Operating reserves curves of least-cost mix with and without VRE vs LDC with 0.005% upper USE limit and no reserves requirement for all CPs

For the least cost generation mixes without VRE available, the operating reserves curves are almost equal for all CP scenarios. Given that in this study, NEMO is not configured to model stochastic generating plant availability, the least cost mix with only dispatchable generation - coal, OCGT, CCGT, hydro, and geothermal - will typically have total generation capacity just below or equal to peak hourly demand over the year. Hence, there will be some periods of no or low reserves, particularly during the higher demand periods in most of the first 2,000 hours of the LDC, as highlighted in the lower part of Figure 9.3.

Meanwhile, the least cost generation mixes with VRE available, including different levels of Coal, CCGT, hydro, geothermal as well as now also PV and wind depending on CP, all deliver significantly higher levels of operating reserves for most of the year. Even without any carbon tax (CP0), the Java-Bali grid gains significant additional reserves during most of the first 4,000 hours of the LDC compared to the case of least-cost generation mixes without VRE. With a carbon tax (CP30, CP60), dynamic operating reserves are pushed even higher during those periods, and over the year, given the greater penetrations of wind and solar in the least cost generation mixes.

Based on the 2-day operating reserves moving average, the minimum system reserves corresponding to the periods of highest system demand are now 0.57 GW, 1.12 GW and 3.58 GW for the carbon tax scenarios CP0, CP30, and CP60, respectively, while the maximum system reserves are now 34.89 GW, 43.30 GW and 44.16 GW, respectively. It is clear that the least cost generation mixes when VRE is available always provide some improvement in minimum available operating reserves and far higher levels of reserves for much of the year than when VRE is not present.

Figure 9.4 shows how the VRE spill (curtailment) rises as VRE penetrations increase with higher CP under the 0.005% upper USE limit and without a reserve constraint. Without a carbon tax (CP0), energy spilled by a total capacity of 24.7 GW PV is insignificant and only occurs during a few periods (around 30 hours) of the lowest demand. Thus, we can conclude that the CP0 operating reserves curve is effectively formed by undispatched fossil-fuel plants displaced by high PV generation during daylight hours.

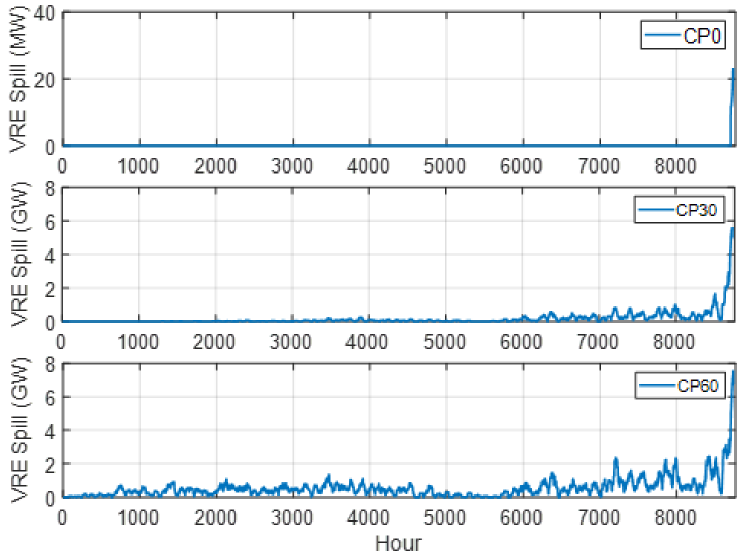


Figure 9.4: Energy spills from least-cost mix solutions with VRE for each CP at 0.005% upper USE limit and without any reserve requirement

In simulations with CP30 and CP60, the least cost mix solutions result in almost double the PV capacity (in CP30) than without carbon tax and eventually, with the significant wind (in CP60), generate greater spill over more hours of the year. Increased spill in CP60 even during high demand periods (most of the first 4,000 hours) is mainly contributed by wind and pushes the corresponding operating reserves curves slightly higher.

9.3.2 Simulation with VRE, no system reserves and with 0.5%-5% USE limit

Relaxation of the system reliability requirement in the NEMO optimisation by increasing the USE limit constraint up to 5%, reduces both total industry generation costs and CO_2 emissions of the least-cost capacity mixes with VRE available and no reserve constraint, for all CPs as shown in Figure 9.5.

Total generation cost reductions of around 11-15% are achievable at the expense of accepting a 5% USE limit by comparison with a much stricter reliability requirement. The cost reductions arise from reduced generation capacity requirements and operating costs to meet those infrequent periods of high demand and low VRE availability.

CO_2 emissions of all least-cost capacity mixes decrease as the carbon tax increases. Nevertheless, some variation of CO_2 emissions exists within the same CP as the reliability requirement changes due to capacity trade-off between coal and gas in some of the least-cost mix solutions.

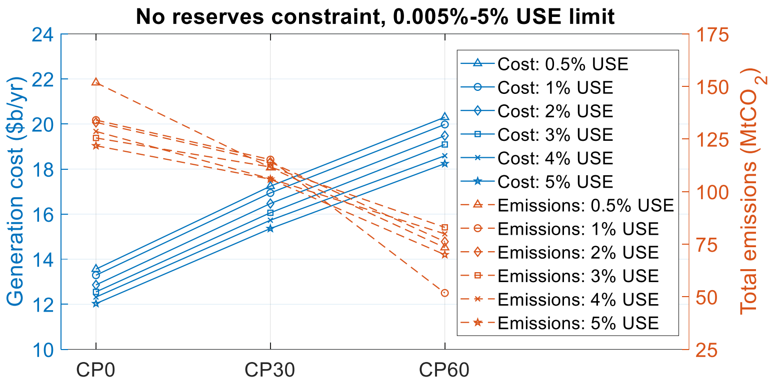


Figure 9.5: Generation costs and CO_2 emissions of least-cost generation mixes as the upper USE limit is varied from 0.5%-5%, and without reserves constraint

Figure 9.6 highlights some of the complex interactions of different CPs and reliability requirements on the least cost capacity mix. Total capacity generally falls with increasing USE limit. The share of fossil-fuel plant capacity in the least cost mix solutions decreases as USE and CP increase, whereas the share of solar PV increases when a carbon tax is imposed.

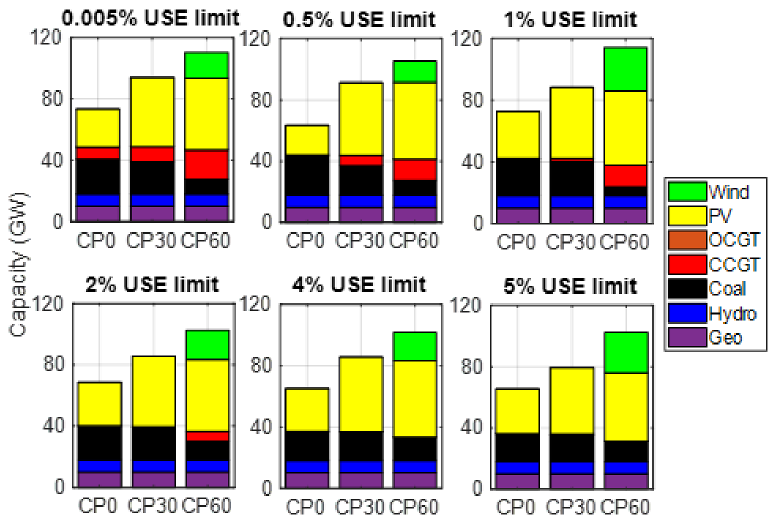


Figure 9.6: Comparison of the least cost capacity mix solutions of all CPs without reserves constraint and with 0.005%-5% upper USE limit and VRE

The composition of coal and gas plants also changes although there are some complexities in gas generation capacity as a CP is introduced, reflecting the trade-off between the higher capital costs and emissions, yet lower operating (fuel) costs of coal versus gas generation. VRE capacity share in the least cost mix solutions increases as CP increases in all USE limits, with a substantial addition of PV built in CP30.

Similar shares of solar PV between CP30 and CP60 are seen across all USE limits presented in Figure 9.6, and eventually wind contributes to the VRE capacity in CP60. Considering a range of different USE limits, the average capacity share of VRE is around 41%, 54%, and 66% of the total capacity in the least cost mix solutions with CP0, CP30, and CP60, respectively. It is notable that this increase is entirely due to wind and solar PV given the maximum capacity constraint of hydro and geothermal renewables on the Java-Bali grid.

Figure 9.7 to Figure 9.9 show dynamic reserves curves – which correspond to the projected 2030 Java-Bali LDC – of the least cost capacity mixes without any reserve requirement and with VRE, with upper USE limits varied from 0.5% up to 5%, for all CPs, respectively.

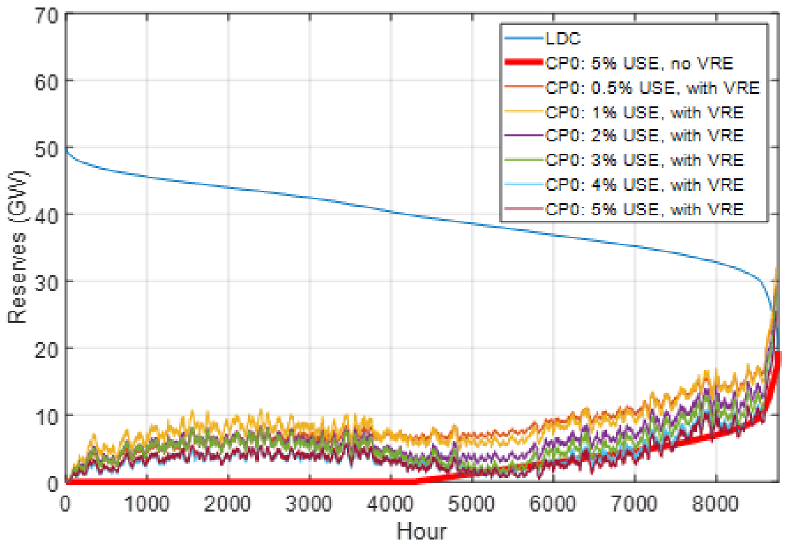


Figure 9.7: Operating reserves curves of least-cost mix with VRE vs LDC at 0.5%-5% upper USE limit and without reserves requirement for CP0 and their comparison with reserves curve without VRE at 5% upper USE limit

The operating reserves for the case of USE 5% and no VRE are also plotted for comparison and (along with Figure 9.3) highlight that, while lower reliability requirements still see VRE adding to operating reserves, there may now be some periods when operating reserves are actually greater for least-cost mixes without VRE (evident from the 5% USE curve with VRE falling below that without VRE for some periods during lower periods of demand over the year).

Without a carbon tax, the maximum availability of the dynamic reserves is up to around 10 GW during most of the first 4,000 hours of the LDC, as shown in Figure 9.7. With a carbon tax of CP30, however, the availability of dynamic reserves is considerably higher as a result of the higher VRE penetration, as shown in Figure 9.8.

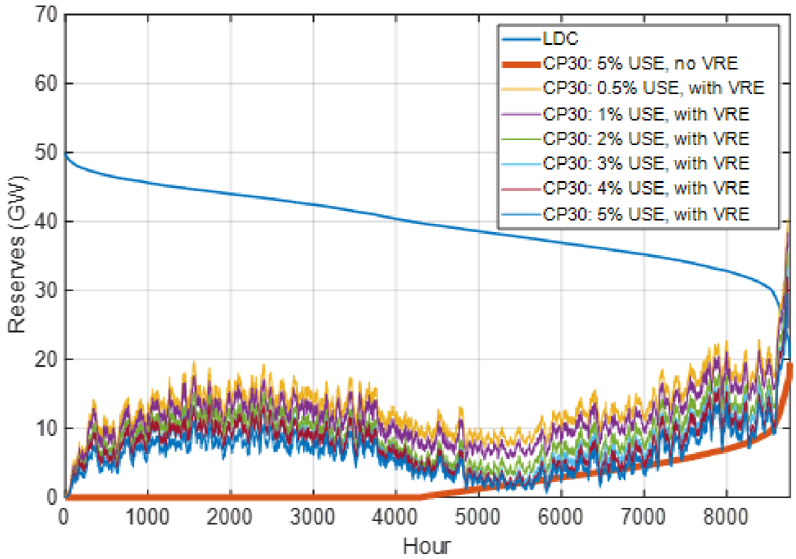


Figure 9.8: System operating reserves curves of least-cost mix with VRE vs LDC at 0.5%-5% upper USE limit and without reserves requirement for CP30, and their comparison with reserves curve without VRE at 5% upper USE limit

There is less additional impact as carbon pricing increases to CP60, as shown in Figure 9.9. Still, CP30 and CP60 provide higher reserves up to almost 20 GW during some periods of the first 4,000 hours (higher demand periods) of the LDC. Higher USE does, unsurprisingly, reduce the levels of these operating reserves but it is notable that for CP60, it is very rare for reserves even at 5% USE to fall below the level available if no VRE is in the least cost mix.

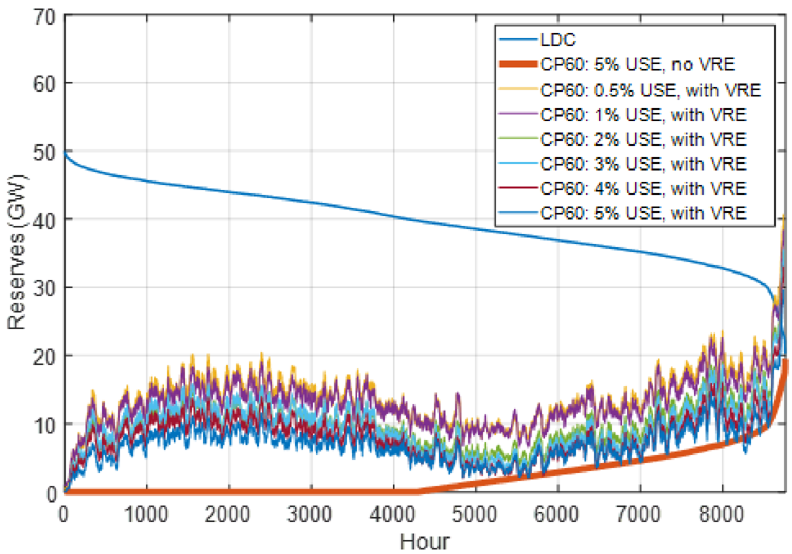


Figure 9.9: System operating reserves curves of least-cost mix with VRE vs LDC at 0.5-5% upper USE limit and without reserves requirement for CP60, and their comparison with reserves curve without VRE at 5% upper USE limit

Table 9.1 (Tanoto et al., 2019) presents a comparison between hours with system reserves less than 30% of that hour's demand, and hours with zero reserves, for the least-cost generation mixes both with and without VRE available and given no reserves constraint.

Hours with low system reserves decrease as CP increases, and hence the VRE penetration increases. Both metrics - the number of hours with operating reserves less than 30% of hourly demand, and hours with zero reserves - increase with higher CP. At CP60, only around 27% of the year sees reserves less than 15 GW or 30% of peak demand – 30% being the system reserve requirement stipulated by PLN for its planning studies. Meanwhile, less than 10% of hours across the year have less than 5 GW operating reserves across all CPs in the case with VRE. As one might expect those hours with operating reserves less than 10% of the demand are typically periods of higher demand.

CP	Least cost mix with VRE		Least cost mix without VRE	
	Hours with reserves < 30% hourly demand	Hours with zero reserves	Hours with reserves < 30% hourly demand	Hours with zero reserves
0	3,640	48	5,580	50
30	2,854	23	5,580	50
60	2,386	15	5,580	50

Table 9.1: Generation costs and CO_2 emissions of all least-cost generation mixes with no reserve constraint

9.3.3 Simulations with 15 GW system reserves

Next, this study considers least-cost generation mixes with a minimum of 15 GW dynamic reserves requirement (representing 30% of expected 2030 peak demand). As with the results obtained in the simulations with 0.005% upper USE limit, total generation costs and CO_2 emissions of the least cost mixes with VRE are lower than those without VRE. As expected, however, costs are now higher with the reserve constraint, due to the additional capacity that must be built. Generation costs and CO_2 emissions of the least cost mixes for all CP scenarios with this minimum 15 GW reserve constraint are presented in Figure 9.10.

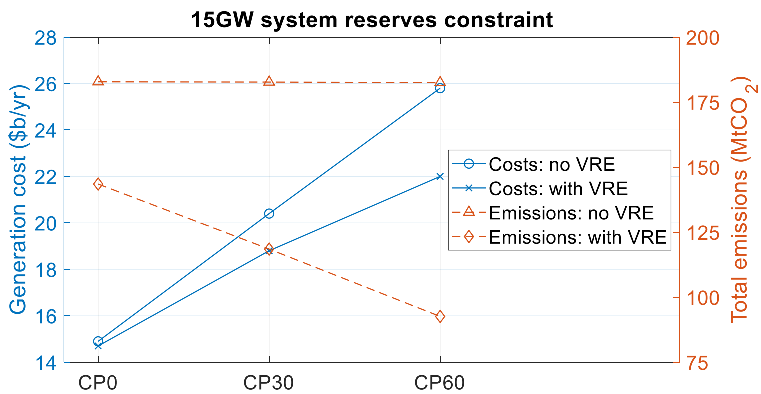


Figure 9.10: Total industry costs and CO_2 emissions of all least-cost mixes with minimum 30% (15GW) reserves constraint for all CPs

The installed capacity of each technology for these least-cost capacity mixes is presented in Figure 9.11. For both the VRE and non-VRE least-cost mixes, we now see the addition of considerable OCGT plant as the lowest cost option for assured additional dispatchable capacity. When VRE is not available, there is relatively little change to the capacity of this OCGT even for the higher CP scenarios. By contrast, the proportion of OCGT/CCGT increases significantly with the higher CP scenarios when VRE is in the mix.

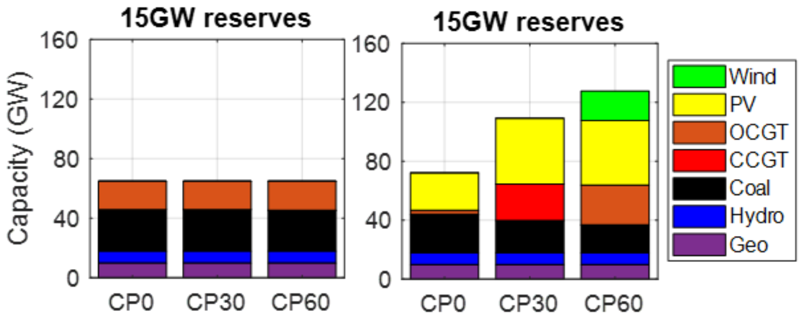


Figure 9.11: Least-cost capacity mixes for all CPs with 15 GW reserves constraint and (left) without VRE, (right) with VRE

Figure 9.12 depicts the 2-day moving average of dynamic operating reserves for the 2030 Java-Bali grid for all scenarios with the 30% (15 GW) minimum reserves constraint. When VRE is not present, these reserve curves are almost equal for all CPs, as highlighted in the lower part of Figure 9.12. Minimum and maximum operating reserves are around 15 GW and 44.6 GW, respectively. With VRE in the mix higher system operating reserves are present due to the higher VRE penetrations, and these reserves increase with the higher CP scenarios (CP30 and CP60). The 2-day moving average curve indicates that an average of more than 30 GW of dynamic operating reserves are available across the highest 2,000 hours of demand, in marked contrast to the case with no VRE. Again, these dynamic operating reserves are higher for the CP30 and CP60 scenarios.

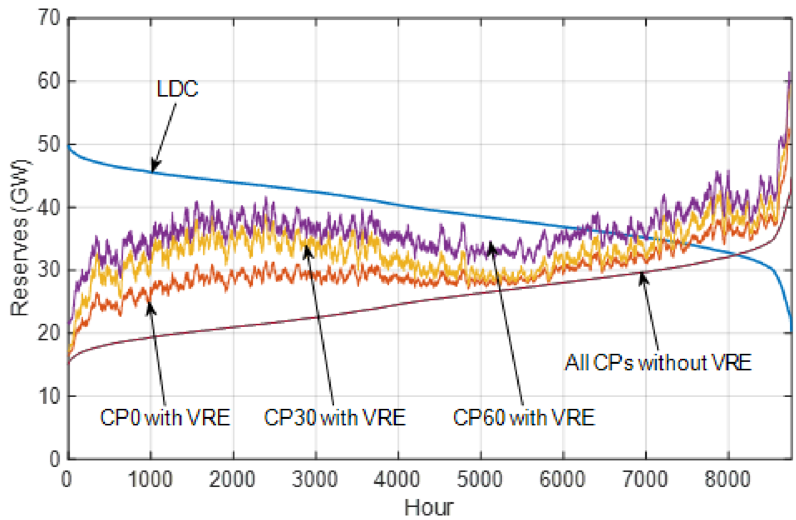


Figure 9.12: System operating reserves curves of least-cost mixes both with and without VRE vs LDC and with minimum 30% reserves constraint for all CPs at 0.005% upper USE limit

The VRE curtailment component of the dynamic operating reserves curves of the least cost mixes with VRE, with a minimum 15 GW reserves constraint and at 0.005% upper USE limit, is presented in Figure 9.13. In the case without a carbon tax (CP0), energy spilled by a total capacity of 25.5 GW PV (a slightly higher-capacity build than without reserves constraint) during the few lowest demand periods of LDC rises to more than three times that seen without a reserve constraint. In simulations with a CP (i.e., CP30 and CP60), higher VRE curtailment results during most of the lower 50% of the LDC for the least-cost mix solutions due to the substantial addition of PV capacity seen in CP30, and even further with the wind capacity added in CP60.

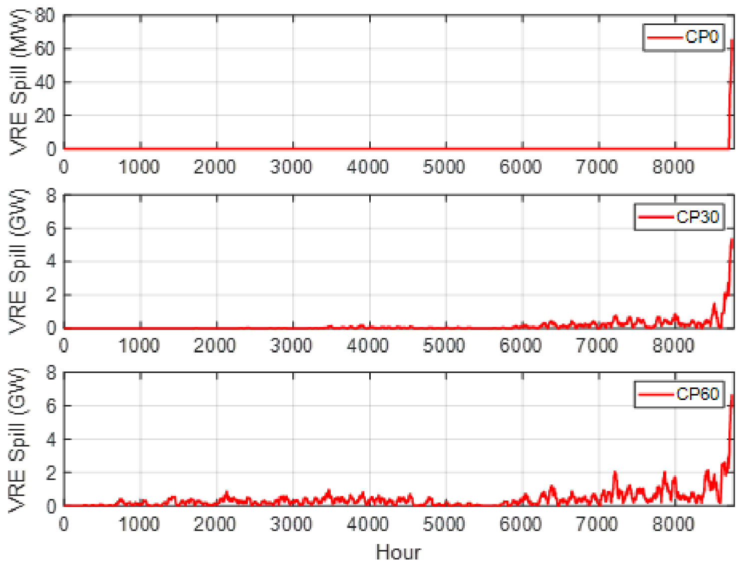


Figure 9.13: Energy spills from least-cost mix with VRE for each CP in the system with 30% reserves constraint and 0.005% upper USE limit

9.4 Conclusions

This chapter presents a study using the NEMO capacity expansion optimisation tool to assess dynamic reserves for different least-cost generation capacity mixes. The assessment approach was demonstrated for the case study of Indonesia's Java-Bali grid. This study solved least cost generation capacity mixes for an assumed 2030 Java-Bali power system demand, based on actual 2015 Java-Bali electricity grid hourly demand scaled at a 5% annual growth rate, and with simulated hourly solar and wind output traces for that same year.

The study constructed reserves curves by plotting a 2-day moving average of hourly dynamic operating reserves against the total grid demand LDC, over a simulated year of power system operation for a range of scenarios, including the availability or otherwise of wind and solar and three CP scenarios, a set minimum of 30% planning reserves requirement, and a range of reliability targets ranging from 0.005% to 5% upper USE limits. The range of scenarios reflects the complex trade-offs present in the electricity sectors of emerging economies where improved reliability must be traded off against the higher industry costs involved. VRE energy spills curves were also plotted for the least-cost mix solutions at 0.005% USE and with and without reserves constraints, for all CPs.

The case study results found that the least-cost mixes with VRE available exhibited lower total industry generation costs and CO_2 emissions compared to those mixes without VRE, for all CPs. Investment in new dispatchable plant is one of the key assumptions here for delivering on the potential of VRE to lower total generation costs and CO_2 emissions. With higher VRE penetrations, with or without a minimum reserve constraint, higher levels of dynamic operating reserves are available at all time periods, including at times of high demand, than are present without VRE in the mix. This is due, of course, to the increased build of the dispatchable plant to cover times of low VRE. The amount of additional operating reserves does, however, vary considerably over the year given the variability of VRE.

In the scenarios with different upper USE reliability requirements, increasing from 0.5%-5% upper USE limit, the share of fossil-fuel plant capacity in the least cost mix solutions decreases across all USE limits, and as CP increases. Higher reliability targets for the same CP provide the system with higher dynamic operating reserves curves for most of the year, including during the periods of high demand.

While these findings are specific to the Java-Bali grid, the insights have broader relevance for electricity industry planners and policymakers in other jurisdictions, particularly in encouraging emerging economies to increase their share of solar and wind penetrations towards a more sustainable electricity industry.

As always, there are limitations to the modelling that suggests caution in a direct interpretation of the results. Better categorising these reserves in terms of 'hot' and 'cold' availability is one area for future work. Another would be more careful consideration of operation without any conventional dispatchable plant running – a situation that does occur in our results for the higher CP scenarios. Still, the general finding would still seem to hold: higher VRE penetrations can offer future electricity industries higher dynamic reserve margins.

Chapter 10
Discussion and Conclusions

This final chapter brings together the findings of the thesis and discusses potential solutions to the challenges it identified for future electricity generation planning in emerging economies. Sections 10.1 and 10.2 summarise the opportunity for, and value of, deploying high variable renewable energy (VRE) within emerging economies' long-term sustainable electricity generation planning, with reference to the research questions RQ1 to RQ6 outlined in Section 4.2. Section 10.3 summarises the contribution made by the thesis, while, in Section 10.4, the limitations of the research are identified, and some suggestions presented for further work in this area. Finally, Section 10.5 presents some brief concluding remarks.

10.1 The opportunity

This section summarises the thesis outcomes in response to the first and second Research Objectives (RO), with reference to the first and second Research Questions (RQ) (see Figure 4.1), as follows:

RO1: To determine the status of, and progress towards, sustainable electricity industries in selected Southeast Asian emerging economies, specifically Indonesia, Malaysia, The Philippines, Thailand, and Vietnam.

RQ1: What useful framework can be used to track the sustainability of electricity industries given the context of Southeast Asia's emerging economies?

Through a review of the literature relating to existing electricity industry frameworks, a contextual framework has been developed for assessing high-level sustainability of the electricity industry in the context of emerging economies. The framework structure consists of three sustainability areas: the supply-side and the demand-side of the industry are clearly delineated and placed within the wider context of environmental sustainability. Common key sustainability dimensions – technical, economic, and social – are embedded into all three sustainability areas. Existing, new, and revised indicators associated with each of the key sustainability dimensions are established and incorporated into the framework.

The framework provides a platform for a cross-country comparative analysis. The sustainability assessment conducted in Chapter 5, using this framework, along with its established set of indicators, found that the electricity industries of most of the ASEAN-5 countries (Indonesia, Malaysia, the Philippines, Thailand, and Vietnam) have exhibited slow progress towards sustainability between 2001 and 2017/2018 by comparison with those achieved by OECD countries. While this is an understandable outcome given the challenges of rapid demand growth and limited resources, it does also highlight potential improvements for the region.

The contextual framework along with the sustainability assessment, as presented in Chapter 5, provides new insights for policymakers and system planners around potential improvements for the sustainability of the electricity industry. As the framework incorporates broader interactions between the supply-side, demand-side, and environmental sustainability aspects of the electricity industry with exogeneous aspects which drive and are subject to the outcomes of the industry. As such it can be utilised as a platform offering innovative approaches for assessing sustainable future electricity generation.

Given the varied electricity industry challenges in emerging economies, the framework is useful for policymakers and system planners in modelling and assessing the supply-side sustainability trilemma, i.e., costs, reliability, and emission reductions. It does communicate the concept of improving and managing the trilemma through high renewable energy penetrations.

RO2: To identify the potential and impact of high VRE penetrations on possible optimum generation portfolios, using the case study of the Indonesian Java-Bali electricity grid.

RQ2: What are the characteristics of solar PV resources in Indonesia's Java-Bali grid and how do they affect future Indonesian electricity industry scenarios?

Mapping a year of Indonesia's Java-Bali solar PV resource in terms of capacity factor, hourly output (ramp rate) and spatial variability, has shown that integration of large-scale solar PV into the Java-Bali grid is technically feasible, although associated with some potential operational challenges due to seasonal solar insolation variation. The highest median PV plant capacity factor in 2015 was 23.63% (September), while the lowest median capacity factor was 11.87% (April). The range of hourly variability across all locations fall within a range of 230-254 kW/hr change per MW of PV plant capacity, while high variability occurred in the months of highest capacity factor. Analysis of the effect of PV plant diversity on aggregate output gives an idea of how much adjustment of hourly output would be required from other generators to maintain the supply-demand balance in the Java-Bali grid. This would be equivalent to 650-850 MW/hr, given a 3.84 GW PV capacity (equivalent to assuming 60% of the 6.4 GW Indonesian 2025 PV target was deployed in the Java-Bali grid, which supplies 60% of demand in Indonesia). Analysis of spatial variability suggests that the most suitable locations for siting utility-scale PV plants are in lowland and coastal areas.

The impact of large-scale utility PV on future Indonesian Java-Bali grid generation planning has been assessed, given the solar resource characteristics in Indonesia's Java-Bali area, through analysis of scenarios comprising different generation technology costs, fuel prices, and demand growth. In Chapter 6, preliminary simulations using an open-source tool, National Electricity Market Optimiser (NEMO), showed that the potential contribution of solar PV to an economically efficient generation mix in 2030 could vary between 2 GW and 35 GW, or up to 16% of the total mix, depending on demand growth scenarios and on future gas prices. Given the relatively low penetration of PV by energy in all scenarios, it does not appear likely that there would be significant integration challenges for 2030 Indonesia's Java-Bali grid.

Given the limited PV share based on the simulation results, the potentials of greater wind deployment for potential reduction of generation costs, hence enhancing affordability in Java-Bali system, are explored in the following chapters. Despite relatively limited wind resources within the area, greater wind penetrations, along with solar, could be realised by considering possible policy intervention, for example through higher carbon prices. Future systems with significant share of solar and wind would see greater implications such as around trade-offs between transmission investment and energy storage.

Java-Bali grid is the largest electricity industry system in Indonesia with currently nearly entirely untapped solar potential for large scale deployment. Given solar resources characteristics in this area, the analysis results of future scenarios for generation mix have shown a clear opportunity and possible pathways toward the decarbonisation of future electricity industry through the deployment of high PV penetrations.

Deeper decarbonisation generally would take longer timeframe beyond 2030. A wider range of scenarios, for example considering either minimum or no fossil generation technologies, could be one way, with more renewable energy sources including wind considered in the planning. The planning on energy storage would be a major implication in the supply-side following the massive uptake of VRE within the system.

10.2 The value of deploying high variable renewable energy

RO2: To identify the potential and impact of high VRE penetrations on possible optimum generation portfolios, using the case study of the Indonesian Java-Bali electricity grid.

RQ3: What are the possible future least-cost generation portfolios with high VRE penetrations under cost/reliability trade-offs?

Solar PV and wind (onshore) were incorporated as candidates, along with other fossil fuel and renewable generation technologies, to assess possible optimum generation capacity portfolios for different reliability levels and carbon prices (CP) in a case study of 2030 Indonesia's Java-Bali grid. The reality of emerging economies is that electricity industry reliability is often significantly lower than that achieved in industrialised economies while adverse environmental impacts are, understandably, not given great weight given more pressing access and affordability objectives. Using NEMO, the level of grid reliability is incorporated in the optimisation algorithm using one of two methods: as a constraint imposed by setting a value of unserved energy (USE) between 0.005% and 5%, and by explicitly pricing the USE.

Using both reliability methods, the simulation results in Chapter 7 exhibit similar results, namely that relaxing reliability requirements sees increasing penetrations VRE while delivering a notable reduction in total generation costs and industry CO_2 emissions reduction. As discussed in Chapter 7, the computational advantages refer to the benefits of applying penalty price on USE over hard constraints for incorporating reliability into the cost function with evolutionary programming. The later approach can cause challenges for the evolutionary process in trying to get as close as possible to, while not exceeding, this reliability target. Meanwhile, the penalty price, as it offers easier and more stable computation, tends to provide a smoother trend of capacity mix outputs. Still, similar results of RE generation shares in the optimum generation mixes using both methods are achieved. Other solution approaches such as Linear Programming (LP) may of course exhibit different behaviour across these two approaches. Geothermal, hydro, coal and solar PV are generation technologies are present in the optimum portfolios across all reliability standards in the scenario without CP. Of course, there are costs associated with lower reliability which will also need to be carefully considered when relaxing the reliability target. Still, this approach might be seen as being more realistic about likely future achieved reliability, in which case there are good reasons to promote higher VRE.

RO3: To understand the impact of incorporating future cost uncertainties of different generation technologies on possible near 'least-cost' secure-affordable-low emissions generation portfolios with high VRE penetrations.

RQ4: How can the concept of energy trilemma be applied to explore the possible range of generation portfolios given future cost uncertainty?

The concept of energy trilemma and its high relevance to this thesis was described through development of an analytic framework of the sustainable supply-side trilemma discussed in Chapter 5, particularly in Section 5.2.2. The mapping of three major 'conflicting' sustainability dimensions (technical, economic, and environmental) on the electricity industry generation side onto three different, but equally important, supply-side key sustainability objectives (reliability, cost, and emissions) was derived and applied in Chapter 8.

Analysis of the possible range of generation portfolios, given future cost uncertainties, was carried out by explicitly exploring the multiple trade-offs between estimated future costs, reliability and environmental impacts in the long-term electricity generation planning scenarios. Using the case study of 2030 Indonesia's Java-Bali generation capacity planning problem, NEMO optimisation functionality was extended to produce a set of 'near least cost' generation mixes by relaxing the cost constraint such that all generation portfolios with a total generation cost within 5% of the least cost solution are retained. This explicitly incorporates future cost uncertainties, in addition to incorporating carbon prices in the modelling to account for some aspects of uncertainty in future coal and other costs. The 'near optimal' outcomes provide the three representative energy trilemma metrics, i.e., achieved reliability (% USE), total generation costs ($/year), and carbon emissions (tCO_2).

RQ5: What are the impacts of possible range of future generation portfolios on the interactions among the energy trilemma's key sustainability metrics?

The spectrum of near least cost portfolios, with a relatively high reliability standard of 0.005% USE obtained from cost-relaxed optimisations (for the case study of 2030 Indonesia's Java-Bali electricity generation planning), were mapped in Chapter 8. For each CP scenario, cluster analysis of these portfolios shows groups of generation technology deployment patterns, characterised by their energy trilemma's key sustainability metrics - achieved %USE, cost, and CO_2 emissions. From all clusters within the same CP scenario, the analysis identifies a 'less emissions' cluster and another 'least cost' cluster, in which the spread of technology mixes can be seen and compared.

Given this innovative approach in the field of long-term electricity industry generation planning, the spread of the emissions and costs in the clusters offers potentially valuable insights for planners into the impacts that might arise from strategies to drive particular technology deployment patterns. The analysis, including the results that, given the uncertainties – notably future technology and fuel costs – highlight the very diverse generation portfolios that delivered costs close to the 'least cost' mix, clearly provides major insights for system planners and policymakers. They may use the approach, i.e., categorising these generation portfolios according to some key metrics for energy trilemma and using clustering techniques to better understand the key performance trade-offs across these metrics, in assessing a wide range of possible pathways towards a more sustainable electricity industry future. Thus, the important insight for policymakers is that they should look a t possible range of future generation portfolios and considering important trade-offs, particularly between costs and emissions, in these choices.

In the case without CP, for example, it is interesting to note that a modest increase in costs allows considerably greater PV and OCGT deployment. Meanwhile, higher PV capacities are deployed in all technology mixes (clusters) in the lower emissions cluster than in the least cost cluster, as CP increases and, interestingly, this increased PV deployment (and hence reduced emissions) comes at what would seem to be fairly low additional costs. The analysis also suggests that there would be a high chance of seeing a greater spread of solar PV and wind deployment in the less emissions cluster, which would make the spread of emissions lower, with lower total generation cost, given expected future cost reductions of these VRE technologies.

RO4: To assess the impact of deploying high VRE penetrations on system dynamic operating reserves, as backup dispatchable capacity required for periods of low wind and solar to provide significant reserves against possible plant failures for much of the time.

RQ6: How can the potential benefit of deploying high VRE penetrations be extended from improving supply reliability to enhancing system security?

The assessment of operating reserves, one of important indicators for power system security, is becoming more challenging and complex due to increased VRE penetrations. Analysis and presentation of the dynamic operating reserves in the context of future electricity industry scenarios, given high VRE penetrations are therefore beneficial to show how system security might be adversely impacted., or actually be enhanced. The work in this thesis on the impact of possible future high solar and wind penetrations might improve reliability of the grid due to the extra dispatchable generation capacity required for those few periods of very low wind and solar availability.

The presence of wind and solar in the generation mixes also enhance the system security when viewed from the point of view of the diversity of fuel types.

As presented and discussed in Chapter 9, the least cost mixes with VRE exhibit lower generation costs and CO_2 emissions compared to those without VRE, for all carbon prices. While the expected system reliability in terms of Unserved Energy (USE) level can be met by all solutions regardless the presence of VRE, availability of VRE in the generation mixes, with or without a minimum reserve constraint, clearly provide higher levels of dynamic operating reserves at all time periods, including at times of high demand.

NEMO is applied to solving possible optimum generation portfolios for 2030 Indonesia's Java-Bali grid that include high VRE penetrations, and then assessing hourly operating reserves, given different reliability requirements, carbon prices, and reserve margin. This novel approach, presented in Chapter 9, highlights and quantifies the opportunities of high VRE penetrations to actually enhance system security through greater system dynamic operating reserves. The constructed reserves curves, compared to the total grid demand load duration curve (LDC), show higher levels of available hourly dynamic operating reserves, including at times of high demand, than without VRE in the mix.

10.3 Thesis contribution

In addressing the six research questions outlined in the previous section (and also listed in Chapter 4), this thesis has contributed to better understanding of the challenges, opportunities, and benefits of incorporating high VRE penetrations for future secure, affordable, low emissions electricity industries in emerging economies. The research methods used, and analyses carried out in the thesis have produced new perspectives, as well as quantitative results and deeper understanding of the nature of this opportunity. The thesis contribution to the body of knowledge relating to the chapters and research questions is shown by the list of publications resulting from the research, illustrated in Figure 1.1, and summarised in Section 1.4.

This thesis has applied and extended the functionality of a sophisticated open-source evolutionary algorithm-based techno-economic optimisation tool, the National Electricity Market Optimiser (NEMO), to the case study of future panning of Indonesia' Java-Bali electricity grid, incorporating a detailed set of technical, financial and system load data.

A comprehensive review of literature on the sustainable electricity industry, particularly in the context of emerging economies (Chapter 5), has driven development of a framework and indicators to assess the status of, and progress towards, more sustainable electricity industries in selected Southeast Asian emerging economies. This framework has also underpinned the research conducted in the thesis, particularly in assessing the sustainability aspect and impact of high VRE penetrations in the electricity industry generation planning.

An assessment of the potential solar resources across locations of Indonesia's Java-Bali grid, in the context of emerging economies, has been carried out using NEMO (Chapter 6), incorporating two aspects: a detailed analysis of hourly solar PV energy output, focusing on capacity factor, temporal and spatial variability; and analysis of the impact of PV plant diversity on aggregate output, with high PV penetrations in future generation electricity industry scenarios.

An extensive techno-economic analysis carried out in Chapter 7, using NEMO and considering two methods for incorporating reliability standards in the optimiser, produced new insights for policymakers and electricity industries planners. This includes analysis of the trade-off between reliability and cost for possible future optimum generation portfolios with high VRE penetrations, given the typically much lower reliability achieved in many emerging economies.

Chapter 8 brought together the concept of energy trilemma with stochastic optimisation to determine possible solution spaces in generation expansion planning, given the complexity of future cost uncertainty, high VRE penetrations, and a range of reliability standards. This research used NEMO and cluster analysis – a novel method in this particular field - to produce and classify possible near-optimum generation technology mixes in future electricity industry planning, according to the key sustainability objectives of the energy trilemma. The findings show a spectrum of possible solutions of secure, affordable, low emissions generation technologies, which can provide policymakers and planners with insights in addressing the particular challenge of conflicting sustainability objectives.

Chapter 9 presents a novel method to assess the impact of high VRE penetrations on future electricity industry scenarios' operating reserves, as one of the most important system security indices, by establishing and assessing system dynamic operating reserves curves. Incorporating different reliability targets, carbon prices and reserve margins into NEMO, this research shows the potential of high solar PV and wind in enhancing system security against potential generator failures and other possible supply interruptions.

While most of these analyses are focused on the context of Southeast Asia's emerging economies, in particular using the Indonesian Java-Bali grid as a case study, much of the work has relevance for electricity industries in other jurisdictions.

10.4 Thesis limitations and further work

The broad aims of this thesis have been necessarily restricted by its scope. While some aspects are explicitly chosen and quantitatively considered, others are excluded from the analyses undertaken. Limited availability of data, time or other resources, in addition to deliberate choices of parameters and focus, have together brought limitations to the thesis. These limitations are classified into three broad aspects to reflect the thesis objectives, and are identified below, along with some suggestions for future work.

10.4.1 Limitations of the sustainable electricity industry assessment

Development of the sustainable framework and selection of indicators for assessing high-level sustainability progress and status of ASEAN-5 electricity industries was based on an extensive literature review focused on the electricity sector. Sustainability in both supply and demand sides of the industry have been considered and given equal attention in the framework's structure, while electricity generation (supply-side) has been further chosen as the focus for a range of analyses undertaken in this thesis. However, the framework and approach could have been validated and refined through interviews or surveys of stakeholders and experts, especially regarding indicators and criteria involved in the cross-country comparative assessment and other innovative indicators with potential relevance to tracking a particular country's progress.

The timeframe for tracking sustainability progress of electricity industries in ASEAN-5 was limited to the period 2001 to 2017/2018, mainly due to limited availability of earlier as well as more recent time series data across countries. If data permitted, it would be beneficial to assess the countries' achievement prior to and after this chosen timeframe. Moreover, as data access in emerging economies is a particular challenge, including in the electricity sector, a number of indicators established from the analysis cannot presently be used for comparison purposes. Meanwhile, future work could further explore the energy trilemma's related indicators -security, affordability, and acceptability aspects - both for the supply-side and the demand-side of the electricity industry. This may include, for example, tracking the progress and status of smart grid or micro grid deployment and customer side participation in producing electricity from renewables, as well as other measurable, innovative supply-demand schemes.

10.4.2 Limitations of the solar and wind resources assessment

There are a number of limitations to the dataset and method applied to determine the potential of solar and wind energy across Indonesia's Java-Bali region, whose electricity grid was used as a case study. As this thesis was started in 2017, the solar resource assessment has employed data gridded hourly solar photovoltaic (PV) power output traces for 2015 obtained from the online tool Renewables Ninja (RN) (see Section 6.2.1). Managing the variability and uncertainty of solar presents challenges over a range of different timeframes, and while Java-Bali dispatch is undertaken on a half hourly basis, PV and demand variability over shorter time frames also poses operational challenges. Nevertheless, the evaluation was based on hourly variability of PV power output due to unavailability of higher frequency data. This research also considered a spatial resolution of 0.05° x 0.05° (5 km x 5 km), which is the smallest resolution available. The reason for selecting 2015 solar PV output data was because of the utilisation of 2015 Java-Bali grid system demand as a baseline in all analyses undertaken in this thesis.

For this one year, the range of monthly PV capacity factors, across locations in the Java-Bali region, hourly ramp rates, including monthly maximum and minimum variability, the effect of PV plant diversity on aggregate output, and spatial variability of PV energy generation have all been assessed. However, no consideration was given to data prior to 2015, given the time required to collect the whole year data for each location across the Java-Bali region. Moreover, a complete dataset for the whole of 2016 was not available during early period of this thesis.

Hourly wind power output traces for 2015 for selected locations were also obtained from modelling available on RN. While locations assigned for wind plant candidates across the Java-Bali region are chosen using the Indonesian wind prospecting map, as used in Chapters 7 to 9, and while wind output traces for all assigned locations were calculated based on 1MW of turbine capacity, the impact of different hub heights and higher turbine capacities (e.g., 2MW) were not assessed. Future work to assess possible wind power output considering different hub heights and turbine capacities may be useful for high VRE integration on long-term generation planning exercises. In particular, the trend to larger wind turbines and larger rotor diameters is improving wind performance.

The Indonesian government has reaffirmed the country's commitment to meet its Paris Agreement target by establishing an Indonesia Low Carbon and Climate Resilience Scenario (LCCR) towards 2050. The LCCR, sees major contributions by the energy sector to decrease the country's emissions by 2050 highlighting major contributions of energy sector to decrease the net emissions by 2050 (UNFCCC, 2021). Indeed, under this low carbon scenario, Indonesia's energy sector will need to almost completely decarbonise its electricity sector over the next three decades, through the massive deployment of renewables. It is envisaged that national power generation from renewables will overtake fossil fuel, with the capacity mix comprising solar PV 113 GW and wind 17 GW, as well as other low-carbon sources (UNFCCC, 2021).

While the needs for high targets of VRE deployment have been acknowledged in official reports, and VRE traces and scenarios can be assessed and modelled in different ways, the NEMO modelling results on the high VRE penetrations could benefits policymakers and system planners.

10.4.3 Limitations of the long-term electricity generation planning modelling

While this thesis has demonstrated the value of using NEMO, an open-source evolutionary programming-based techno-economic optimisation model, to better understand the potential of high VRE penetrations in sustainable electricity industry transition there are, of course, limitations to the modelling that suggests caution in direct interpretation of the findings.

There is a lot of uncertainty in forward looking planning exercises, and particularly in electricity industry planning, and incorporating this uncertainty in the analysis is an important part of this thesis' contribution. While Indonesia's Java-Bali grid was chosen as a case study to represent the context of electricity industries in emerging economies, the modelling encountered some uncertainties which provided an opportunity to explore the solution space in more detail rather than simply solving for the 'least cost' solution.

Chapters 7 and 8 explored trade-offs, yet also potential synergies, of future generation portfolios across the entire key sustainability metrics, and while the stochastic evolutionary programming technique was applied to explicitly consider uncertainty in the results, in addition to pursuing least cost solutions, the modelling comprises some limitations. These include the limited availability of data, limitations in the tool, and limitations in the analysis. Data is certainly an important limitation, as it is always changing over time and locations, as well as its resolution. When it comes to the numerical data, this thesis has embraced the reality of an uncertain future, as a characterisation of future planning. In Chapter 6, uncertainty in the modelling was captured in a modest, limited manner by assuming different future demand growth, fuel prices, and technology cost scenarios to obtain the lowest cost solutions. These lowest cost solutions were highly dependent on the cost and constraint assumption 'inputs', such as carbon pricing (CP) and build limits for certain generation technologies. As discussed in Section 8.1, a relatively small change in estimated future costs for any generation technology may entirely change the 'least cost' outcome. As a consequence, a different generation portfolio may be only slightly more expensive, or even cheaper due to gradually decreasing cost of wind and solar PV but have extremely desirable characteristics for planners. Meanwhile, the outcomes presented in Chapters 7 to 9 have been dependent on an assumed value of 5% annual demand growth to 2030, as these sections have been more focused on exploring the possible solution space due to uncertainties of future costs and the potential of high VRE penetrations on the dynamic operating reserves.

A limitation of the tool is that NEMO undertakes 'greenfield' capacity expansion; that is, it solves all new build generation mixes without dealing with existing generation capacity in a single investment time step. Moreover, the inherent stochasticity of evolutionary programming has some disadvantages compared with other tools using deterministic methods. Limitations in the analysis include the omission of indirect emissions, such as those produced during RE based technologies manufacturing, in the modelling. In addition, system flexibility was not explicitly taken into consideration in the modelling undertaken across Chapters 6 to 9, noting that this thesis has discussed and analysed capacity ramp up due to integration of high VRE penetrations such as PV into power systems (see Chapter 6).

Future work might address some of these limitations, while also using updated datasets as current modelling could give different results to that obtained three years ago at the start of the project. However, as wind and solar become more cost competitive and grid technology could mitigate most of the impact caused by variability and uncertainty of the VRE resources, it is almost certain that these modelling outcomes would confirm the benefits of high VRE penetrations. NEMO functionality could also be improved to enable a greater range of analyses, for example by adding a system flexibility analysis toolbox, or by enhancing the tool capability to allow multi-year assessment with existing and/or planned generation capacity mix for the case of long-term generation expansion planning. NEMO could be used in many ways, by enhancing the tool capability, that would enhance policymaking insights, particularly through modelling scenarios that encompass different policy approaches, to reflect different possible pathways towards a more sustainable electricity industry future.

10.4.4 Opportunity for broader future work

Beyond addressing the limitations identified in the modelling, future work on the area of sustainable electricity generation expansion planning, particularly given the context of emerging economies, is an interesting and important area for future investigation. While electricity industries in many of these jurisdictions are transitioning toward a more sustainable future, broader future work could explore, for example, possible relationships between ambitious sustainability targets, barriers, and potential outcomes, as well as the challenges of deploying high VRE penetrations and suitable power system regulations and arrangements leading to low or zero carbon emissions. More technically, this could involve analysis of options such as scattered distributed energy resources for possible smaller but secure electricity grid arrangements, which would be either suitable for interconnection or robust, stand-alone networks, or other arrangements which may be suitable for improving high-level electricity industry's sustainability objectives for typical archipelago jurisdictions.

More broadly, future research could see jurisdictions such as in ASEAN-5 consider net zero emission commitments as the ultimate target of their clean and sustainable energy policy efforts. Regional cooperation on power sector interconnection, as it has long been planned in ASEAN, has a potential to assist nations with implementation of this net zero carbon transition. Identification of the high potential for high VRE penetrations, as explored in this thesis, could provide policymakers and planners with important insights for further explorations, for example, of strengthening networks and developing technologies to extend the grid, or of the opportunity for future zero emission energy trade, as VRE technologies become more competitive.

10.5 Concluding remarks

There is a real and significant opportunity identified by this research for integration of high VRE penetrations into future electricity industries, particularly those in emerging economies, to help deliver ambitious emission reduction targets.

The potential of electricity industry's basic structure in terms of the supply and demand side has been identified in this thesis through development of a framework along with a set of indicators covering important sustainability aspects of the industry. The usefulness of the framework for jurisdictions in assessing their electricity industries' high-level sustainability progress and status has been demonstrated.

The assessment of wind and solar resources and modelling of long-term electricity generation planning using novel methods and innovative approaches, based on this framework, have sought to address some limitations found in the existing generation capacity planning exercises undertaken by utilities. More importantly, while the modelling exercises provided by the utilities and presented in the literature are valuable, the research also sought to provide insights for planners and industries to better utilise modelling into their decision making. This thesis has demonstrated possible pathways for future secure, affordable, and low emissions generation portfolios, by emphasising the potential of high VRE penetrations and showing the range of generation capacity portfolios with lower cost and CO_2 emissions potentially available.

While the research does not primarily aim to recommend any particular, preferred policy derived from the modelling it has highlighted an important role for environment-based policy in supporting high VRE deployment, as identified in the modelling outcomes relating to possible future generation portfolios and dynamic operating reserves.

The policy analysis as presented in Chapter 2, 3, and 5, nevertheless, has highlighted important insights for policymakers and system planners regarding the high-level status and progress for the transition to more sustainable electricity industries in ASEAN-5 countries, particularly given the context for high VRE penetrations in the region. Potential implications, and hence high-level recommendations for the policy frameworks in the ASEAN-5 countries, and Indonesia in particular, can be drawn from the analysis undertaken in these chapters.

These recommendations include the establishment and implementation of policies that encourage and facilitate progressive switching from fossil fuel-based generation to large scale renewables, including wind and solar, given the economic and environmental value they can provide. Establishment of rigorous plans indicating the transitioning stages and pathways for a more sustainable electricity industries, considering both the supply and demand sides' key parameters could be beneficial in helping policymakers and planners to monitor and evaluate progress. Meanwhile, global warming requires fossil-fuel producing country like Indonesia to resolve some issues pertaining to their present favourable treatment and policies supporting the utilisation of coal. In the end, the political will from the government remains one of the critical key drivers to the successful deployment of high renewables in transforming the electricity industries.

The linkage between the outcomes of the policy analysis, notably the policy framework gaps identified in Chapter 2 to 5 and particularly summarised in Chapter 3, and the modelling research of Chapter 6 to 9 was outlined above in Section 10.1 and 10.2. In particular, the modelling highlights the value of much higher VRE penetrations in delivering improved industry outcomes, the role that carbon pricing can play in assisting such deployment, and the wide range of low-emission generation mixes that might achieve roughly similar industry cost reductions. In this way, the modelling research has offered meaningful insights not only in dealing with present knowledge gaps but also improving the policy framework in ASEAN-5 countries.

More research is needed to improve the model capability, particularly in exploring the impact of drawing together possible policy options, either in the supply or demand side, and incorporating various, wider uncertainties of future costs, assumptions, and resources, on possible sustainable generation portfolios.

After all, this thesis is just one of so many other contributions aiming to promote technically and economically feasible-high VRE uptakes amid uncertainty, to support the transition of electricity industries in emerging economies toward low and eventually zero emissions futures. Nevertheless, utilities urgently need greater support, systematic inter-sectoral actions, and possibly cross-boundary cooperation to help improve energy services while also understanding the impacts resulting from ongoing development of the energy sector.

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