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CO-OPTIMIZING NETWORK, PUMPED AND BATTERY STORAGE INVESTMENTS UNDER LONG TERM UNCERTAINTIES: A CASE STUDY ON AUSTRALIAN POWER SYSTEM

TESIS PARA OPTAR AL GRADO DE MAGÍSTER EN CIENCIAS DE LA INGENIERÍA, MENCIÓN ELÉCTRICA

MEMORIA PARA OPTAR AL TÍTULO DE INGENIERO CIVIL ELÉCTRICO

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RESUMEN DE LA MEMORIA PARA OPTAR AL TÍTULO DE INGENIERO CIVIL ELÉCTRICO Y DE LA TESIS DE MAGÍSTER EN CIENCIAS DE LA INGENIERÍA, MENCIÓN ELÉCTRICA
POR: BASTIÁN NICOLÁS MOYA URETA
FECHA: ABRIL 2021
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The pace at which variable renewable energy generation (VREG) is adopted depends on several uncertain factors, hindering the prediction of their penetration in the upcoming years. Therefore, the consideration of uncertainty in system expansion models becomes a key issue to appropriately study the role of storage technologies in future prospective scenarios.

This thesis implements a 2-stage stochastic mixed integer linear program to co-optimise the investment in storage and transmission lines along with the operation of the electrical system. The model includes an hourly operation and a transportation model for lines. Moreover, the generators consider a detailed operation, including ramp-up/down, minimum up/down time, maximum/minimum operating point, and upward reserves. To address the computational burden, the problem is decomposed with a Dantzig-Wolfe decomposition, and it is implemented in a 5-node system of the National Electricity Market, considering five future scenarios.

The results show that the optimal stochastic portfolio reaches a lower expected total cost than the deterministic portfolios. Moreover, the results show two relations between lines and storage investments. Firstly, the optimal portfolio includes lines and pumped storage to transfer the excess of VREG from regions with low demand. Secondly, battery investments defer line investments in regions with high demand.

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El ritmo al cual son adoptadas las tecnologías de generación variable (VREG) depende de diversos factores inciertos, los cuales dificultan la predicción de su penetración en los próximos años. Por lo tanto, la consideración de incertidumbre en los modelos de expansión es fundamental para estudiar apropiadamente el rol del almacenamiento en escenarios futuros.

Esta tesis implementa un modelo entero mixto estocástico de dos etapas para co-optimizar inversiones de almacenamiento y transmisión con la operación del sistema eléctrico. El modelo incluye una operación horaria y un modelo de transporte para líneas. Además, los generadores consideran en la operación: rampas máximas, tiempos de encendido/apagado, mínimos/máximos técnicos y reservas de subida. Para abordar la carga computacional, el problema es descompuesto con la descomposición de Dantzig-Wolfe e implementado considerando cinco escenarios en un sistema de 5 barras del National Electricity Market.

Los resultados muestran que el portafolio estocástico alcanza un costo total esperado más bajo que los portafolios deterministas. Además, se pueden apreciar relaciones entre inversiones de líneas y almacenamiento. Primeramente, el portafolio optimo incluye líneas y centrales de bombeo para transferir el exceso de VREG desde regiones con baja demanda. Además, las baterías desplazan la inversión en líneas en regiones con alta demanda.

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Chapter 1

Introduction

1.1. Motivation

In recent years, countries around the world have been committed to reduce carbon emissions. For instance, Australia has international commitments to reduce these emissions by 26–28% below 2005's levels by 2030 [1]. Since the electricity sector is the largest producer of carbon emissions, with 35% of total emissions [2], there is increasing pressure in the industry, which has pushed system planners to make new approaches to plan the future systems.

Decreasing emissions implies various changes in the future power systems, bringing new challenges to the different market agents. There is a consensus among the international community that there will be three key system changes and operational challenges for the upcoming years [3]–[7]: 1) Changing the supply mix, which means more variable renewable energy generation (VREG) and less dispatchable generation; 2) Impact of weather, considering rises in temperature and an increase in the frequency of extreme weather events; and 3) A change in the electricity demand, given by higher ramps for peaks, lower minimum demand, more active costumers along with more distributed energy resources (DER). For system planners, these challenges result in uncertainty about the future. For instance, the Australian Energy Market Operator (AEMO) projects a growth in installed capacity of VREG technologies, which might reach 47 GW installed by 2040 [8]. Similarly, DER generators (rooftop PV and PV under 30 MW) could provide between 13% and 22% of the total underlying annual National Electricity Market (NEM) energy consumption by 2040 [8]. Moreover, the installed batteries at distribution level could reach 30 GW by 2040 [9]. Therefore, the VREG and DER technologies will play an important role in the energy system in the upcoming years having a strong influence in both distribution and transmission/generation level [5].

The renewable energy zones are usually in different places of the electrical systems, and they are not necessarily close to the demand centres. Moreover, there are regions which have more renewable energy potential. In order to share this resource with other regions, the development of the VREG must be made along with investment in lines and storage systems, to avoid bottlenecks in transmission lines, to supply electricity in the peak demand hours and to sort different conditions of the variable resource.

Therefore, given these challenges and the nature of VREG technologies, new tools are needed to calculate the optimal portfolio of lines and storage in the electrical systems. These tools must be able to capture the relation among these investments and address the short-term variability along with long-term uncertainties.

1.2. Proposed Hypothesis

This research seeks to demonstrate that by considering long term uncertainty in a highly-detailed operational model in the co-optimization of lines and storage in the NEM, it is possible to appreciate two phenomena: Firstly, a complementary effect between the investment in lines and the storage in regions with high renewable potential; secondly, a deferral effect in zones where storage can deal with peak demand.

1.3. Objectives

1.3.1. General objective

- To implement and develop a stochastic planning model with a detailed operational model to analyse the role of different types of storage in the transmission expansion planning problem in the NEM, considering different scenarios and case studies.

1.3.2. Specific objectives

- To address the uncertainty about the future using different scenarios with various penetration levels of renewable energy resources and a detailed operational model.
- To identify the impact of considering different kinds of storage technologies in the medium- and long-term line investment decisions.
- To comprehend the operational conditions which make planners invest in more lines or storage.
- To understand the impact of planning the NEM system considering different maximum demands.

1.4. Contribution

The findings from this study make two main contributions to the existing literature. Firstly, despite the variety of studies and model approaches to solve the planning problem, the incorporation of a stochastic investment model that includes an hourly solution with a detailed operational model for generators has still not been addressed properly.

The second contribution of this work is understanding the impact of different types of storage in the transmission expansion planning (TEP) problem, and under what conditions line and storage investments might be complemented or deferred by each other's investment. By running different study cases this research shows a complementary effect between the investment in lines and storage plants in regions with high renewable potential; and a deferral effect in zones where storage can deal with peak demand. In this vein, this research sheds new light on the effect of storage in the TEP problems considering a stochastic approach.

1.5. Structure of the document

The remaining of this thesis is structured as follows. Chapter 2 presents a literature review of the planning problems and their challenges. Chapter 3 provides the model formulation. Chapter 4 details the case study and input data. The results and discussion are presented in Chapter 5. Finally, Chapter 6 shows conclusions and future work.

Chapter 2

Literature review

Currently, electrical systems are facing a change from a conventional system to a new decarbonized and decentralized system. In this context, there are three challenges for the planning problem [3]–[6], [10], [11]: 1) Changing the supply mix, which means more VREG and less dispatchable generation; 2) A change in the electricity demand, given by higher ramps for peaks and more DER; and 3) Impact of weather, considering rises in temperature, which might imply higher and more frequently maximum demands (MDs). The following paragraphs will provide an overview of each of these challenges.

The first challenge is the changing in the supply mix. In order to address this challenge, planners need to tackle two significant issues in the upcoming years: in the operational or short-term models, the hourly variability of VREG is crucial to understand the role of storage and lines; and in the planning or medium/long term models, it is important to include the uncertainties about new policies, investment costs and the high penetration of VREG to reach an optimal portfolio of generators, lines and storage [10]–[13].

To understand the role of generators, lines and storage in the future electrical systems, the co-planning among these technologies has been carried out in recent years. The co-planning of these technologies can be classified into four co-optimization categories: the generation and transmission expansion planning; the storage and generation expansion planning; storage and transmission expansion planning; and the storage, transmission and generation expansion planning. By co-optimizing more than one of these technologies, the computational burden increases. This is due to the fact that the number of investment decisions and the details of each model increase. Since this thesis focuses on the impact of storage in the TEP, the co-optimization between transmission and generators is out of its scope; however, there are several studies which have made an effort to understand the impact of the co-optimization of these technologies in the system [14]–[16].

The co-optimization of storage and lines has been carried out considering different assumptions. In [17],the impact of batteries in the TEP was studied using various demand blocks in a 27-bus model of the Chilean system. The results show that under their simplified model of the operation, the investment in batteries promotes the installation of more lines in some cases. However, these results were obtained using demand blocks and it is unclear the role of storage in the provision of energy arbitrage in chronological order, which is a key issue in systems with high penetration of VREG [11] . In [18], the authors have introduced a daily profile considering two demand blocks, which represent low and peak demands. They have implemented the model with a Benders decomposition to study the TEP considering storage. The model is implemented in three systems: Garver's 6-bus system, IEEE 25-bus and a 46-bus Brazilian system. The results show that in some cases, the installation of storage is an effective means of transmission upgrade deferral. Although this study has improved the chronological representation of the demand, two demand blocks are not enough to capture the variation of demand and renewable generation. In [19], the authors have introduced a chronological order by studying a daily demand with six constant-demand intervals. This demand was used for the 365 days of the year. They implemented a MILP formulation to analyse the impact of batteries in two test systems: modified Garver's system and IEEE 24-bus system. They concluded that in some cases, the inclusion of batteries delays the construction of lines. However, the limitations of this study are the lack of inclusion of different types of storage plants, and the utilization of constant demand curves. The inclusion of several storage technologies has been study by Wang et al. [20]. They have included batteries and pumped storage plants using a nested column and constraint generation algorithm with a robust approach. The formulation is implemented considering renewable power uncertainty. The model is used to study the relationship between line length and storage investment in a system with high VREG penetration, concluding that batteries are better to alleviate congestion than long-distance transmission lines. Nevertheless, this study does not consider uncertainty about future demands, different future penetration of VREG and different levels of DER.

In [21], two storage technologies have been included in the TEP problem: small pumped storage and batteries. The problem was implemented as a stochastic model considering long-term uncertainty for demand growth as well as available generation capacity. This study considerers a 24-hour profile in two systems: a 6-bus model and a reduced model of the Chinese electrical system. The results highlight that the inclusion of storage reduces transmission requirement and allows the efficient integration of wind power. Although this approach allow to understand the impact of two storage technologies in the TEP problem, the authors have not included commitment constraints, which might lead to underestimate the operational cost [22]. Moreover, the source of uncertainties does not consider different penetration of DER. Similarly, Falugi et al. [23] have proposed a novel Benders decomposition, considering 27 scenarios with different daily demand profiles and wind penetration in a multi-stage scenario tree. The model is implemented without considering commitment constraints in the IEEE 118-bus system, including three types of storage options: Pumped storage, compressed air energy storage and batteries. This paper highlights the importance of considering small and large-scale storage plants due to their different deployment time. Although this paper included different scenarios, the scenarios do not consider different penetration of DER.

The studies presented thus far show relations between the investment in storage and lines considering different assumptions. However, none of these studies has consider the impact of DER in the future systems, which might change the optimal portfolio [5]. Moreover, most of these studies have ignored unit commitment constraints, and they do not consider the intraday energy arbitrage of storage plants. In fact, in [11] was reported that one of biggest challenges of the storage expansion planning (SEP) problems is the inclusion of a high temporal resolution along with the unit commitment constraints of conventional generators.

The inclusion of the unit commitment constraints in the co-optimization of storage and generators has been shown by Poncelet et al. [24], who studied the value of storage by providing flexibility, and Diaz et al. [25], who studied the impact of different levels of modelling complexity. Both papers studied the system with unit commitment variables without considering transmission lines and highlighting the fact that to neglect unit commitment constraints in the planning problem leads to suboptimal solutions. The inclusion of unit commitment constraints in a generation expansion planning (GEP) problem has also been studied in [22], [26]. These research articles agree with the fact that neglecting the unit commitment constraints increase the total cost of the electrical system.

The second challenge of the future electrical systems is the impact of DER in the expansion planning problem. Pérez-Arriagada [5] comments about the impact of DER technologies in the upcoming years, highlighting that the inclusion of these technologies will modify the optimal investment in lines in the TEP problems.

The impact of different distributed generators (DG) in lines in a distribution system has been studied in [27], [28]. The results of these papers highlight that the investment in DG may defer the reinforcement of lines in a distribution level, depending on the size, location and the type of DG. However, these research articles are limited to the distribution system, and the impact in the transmission system is not addressed. Luo et al. [29] have study the impact of DG in the TEP. They have implemented an AC-OPF model in the Queensland transmission system. They conclude that the solar PV would have a stronger effect on transmission investment deferral than wind generators. This is due that the deployment of wind generators could be made in one area of Queensland, but the solar resource is available in all the system. Although the TEP was study including DG, the impact of storage is not addressed. Similarly, Alvarado et al. [30] studied the impact of various DER resources in the TEP problem with a novel mathematical approach, concluding that considering DER services in the planning problem can defer network investment. Gomes and Saraiva [31] have studied the TEP problem considering different levels of solar DG penetration in the distribution networks. Their results indicated that solar DG is not able in an isolated way to reduce the investment in transmission. The authors suggest that the DG generators must be complemented with storage or demand response programs in order to reduce the investment in transmission networks. This study was limited to assess the impact of DG in the TEP; therefore, it is unknown the impact of different storage technologies. Finally, the impact of electric vehicles in the co-optimization of lines and generators has been addressed in [32], where the authors concluded that the use of smart charging patterns can impact the planning by affecting the peak hours and leading in higher investment in PV technologies. Being limited to the co-optimization of lines and generation considering Electric vehicles (EV), this study does not study the impact of storage in the planning problem. Despite their contributions, one important drawback in all the studies reviews about the inclusion of DER in the planning problem is that the different levels of DER technologies have not been included in the co-planning of storage and lines. Therefore, how different penetration of DER affects the co-optimization of the operation of the system along with the investment in lines and storage remains unclear.

Finally, the last challenge of the electrical system of the future is the weather changes. These phenomena increase the MD due to extreme weather events [7], [33]–[35]. The inclusion of different MDs has been carried out by AEMO in [33], [36]. They include different demands with various probability of exceedances (POE) in the TEP of the NEM system. The POE has been built for 90%,50% and 10% probability of exceedance, where 90% means MD is expected to be exceeded on average nine years in ten; 50% one year in two; and 10% one year in ten. In this vein, considering a POE 10% implies to consider the highest MD given by events such as cool/heatwaves but with a similar condition for the rest of the year. AEMO includes in the TEP the POE 10% demand as load blocks to choose a portfolio to evaluate under more detailed demand models. Nevertheless, the applied model does not allow the planner to capture the impact of storage in the hours of MD. In the academic literature, seasonal peaks and coldwaves have been addressed in [34] to co-optimize generation and transmission in the European electrical system. Although their results highlight that the extreme weather conditions could require the installation of additional back-up capacity, the impact of different storage plants in the line investment have not addressed.

Chapter 3

Model

Nomenclature

AEMO	Australian Energy Market Operator
BON	Battery of Nation
CCGT	Combined-Cycle Gas Turbine
DER	Distributed Energy Resource
DG	Distributed Generators
ENS	Energy not Supplied
ESS	Energy Storage Systems
EV	Electric Vehicles
GEP	Generation Expansion Planning
MD	Maximum Demand
MMA$	Millions of Australian dollars
NEM	National Electricity Market
NSW	New South Wales
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedance
PS	Pumped Hydro Storage

PVNSG	Photovoltaic Non-scheduled Generation
QLD	Queensland
SA	South Australia
SEP	Storage Expansion Planning
TAS	Tasmania
TEP	Transmission Expansion Planning
VIC	Victoria
VOLL	Value of Lost Load
VPP	Virtual Power Plant
VREG	Variable Renewable Energy System

Parameters

$C_{g,m}^{fuel}$	Fuel cost of generator g in scenario tree node m [A$/MW]
C_g^{rp}	Ramp-up cost of generator g [A$/ΔMW]
C_g^R	Upward reserve cost of generator g [A$/MWh]
C_g^{sd}	Shut-down cost of generator g [A$]
C_g^{up}	Start-up cost of generator g [A$]
$D_{\omega,n,t}$	Electricity demand of node n in week ω and time t [MW]
Dt_g	Minimum down time of generator g [h]
$\bar{E}_s^C$	Maximum energy of candidate storage plant s [MWh]
$\bar{E}_s$	Maximum energy of existing storage plant s [MWh]
$\bar{F}_l$	Maximum power flow capacity of line l [MW]
$\overline{Fr}_l$	Percentage of line capacity to import/export reserves of line l [-]
$\mathcal{F}_g$	Full outage rate of generator g [-]
$\bar{L}_l$	Power flow capacity of candidate line l [MW]

$\bar{M}$	Big number [-]
$nG_{m,g}$	Total available unit of generator g in the scenario tree node m [-]
$\wp_g$	Partial outage rate of generator g [-]
$\bar{P}_g$	Maximum power output of generator g [MW]
$\underline{P_g}$	Minimum power output of generator g [MW]
$\bar{P}_s^C$	Maximum power output of candidate storage plant s [MW]
$\bar{P}_s^E$	Maximum power output of existing storage plant s [MW]
$Pl_{\omega,v,t}$	Renewable profile of renewable generator v in time t and week ω [-]
$\overline{Pr}_{m,v}$	Maximum power output of renewable generator v in scenario tree node m [MW]
r	Discount rate [-]
$R_{t,n}^0$	Reserve requirement of node n in time t [MWh]
$Ramp_g$	Ramp rate limit of generator g [-]
$\mathcal{u}_g$	Unavailability of generator g [-]
Ut_g	Minimum up time of generator g [h]
$Voll$	Value of lost (or curtailed) load [A$/MWh]
W_ω	Number of times that a representative week ω is repeated within one year [-]
y^0	Reference year to which all costs are discounted [-]
yr_m	Milestone year in the scenario tree node m [-]
α_g	Derating factor of generator g due to partial outage [-]
η_s^{ch}	Charge efficiency of storage plant s [-]
η_s^d	Discharge efficiency of storage plant s [-]
$\bar{\mu}_b^B$	Maximum investment of candidate battery b [-]

$\bar{\mu}_l^L$ Maximum investment of candidate line l [-]

$\xi_{\omega,g}$ Seasonal factor of hydro generator g in week ω [-]

$\Pi_{b,m}^B$ Investment cost of candidate battery b in the scenario tree node m [A$]

$\Pi_{l,m}^L$ Investment cost of candidate line l in the scenario tree node m [A$]

$\Pi_{p,m}^{PS}$ Investment cost of candidate pumped storage p in the scenario tree node m [A$]

ρ_g Percentage of capacity of committed generator g to provide reserves [-]

ϕ_m Probability of scenario tree node m [-]

ψ_s Reserve provision time of storage plant s [h]

Variables

$E_{t,s}$ Energy of storage plant s in time t [MWh]

$F_{t,l}$ Power flow of line l in time t [MW]

$Fr_{t,l}^{fw}$ Forward reserve flow of line l in time t [MW]

$Fr_{t,l}^{rv}$ Reverse reserve flow of line l in time t [MW]

I_m Investment cost in scenario tree node m [A$]

O_m Operational cost in scenario tree node m [A$]

$P_{t,g}$ Power output of generator g in time t [MW]

$P_{t,s}^d$ Power discharged of storage plant s in time t [MW]

$P_{t,s}^{ch}$ Power charged of storage plant s in time t [MW]

$Pf_{t,n}$ Curtailed load of node n in time t [MW]

$Pr_{t,v}$ Power output of renewable generator v in time t [MW]

$R_{t,g}$ Reserve of generator g in time t [MWh]

$R_{t,s}^C$ Reserve of candidate storage plant s in time t [MW]

$R_{t,p}^E$ Reserve of existing storage plant p in time t [MW]

$rp_{t,g}$ Change in electrical power output of generator g in time t [MW]

$sd_{t,g}$	Number of shutting down units of generator g in time t [-]
$up_{t,g}$	Number of starting up units of generator g in time t [-]
$X_{t,s}$	State of charge of storage plant s in time t [-]
$\mu^{L}_{l,m}$	Candidate line l in scenario tree node m [-]
$\mu^{B}_{b,m}$	Candidate battery b in scenario tree node m [-]
$\mu^{PS}_{p,m}$	Candidate pumped storage p in scenario tree node m [-]
$\mathcal{X}_{t,g}$	Number of online units of generator g in time t [-]

Sets

B_n	Set of existing batteries in node n
$\hat{B}_n$	Set of candidate batteries in node n
G_n	Set of generators in node n
G_n^H	Set of hydro generators in node n
L_n	Set of existing lines in node n
$\hat{L}_n$	Set of candidate lines in node n
M	Set of nodes in the scenario tree
M^S	Set of sibling nodes in the scenario tree
N	Set of nodes in the 5-node system
PS_n	Set of existing PS plants in node n
$\widehat{PS}_n$	Set of candidate PS plants in node n
S_n	Set of existing storage (PS_n and B_n) in node n
$\hat{S}_n$	Set of candidate storage ($\widehat{PS}_n$ and $\hat{B}_n$) in node n

T Set of time steps within a representative week

Υ_n Set of renewable generators in node n

Ω_m Set of weeks within one year in the scenario tree node m

3.1. Overview of the model

In order to understand the impact of the variability of the VREG along with the constraints of the conventional generators in a planning model of transmission and storage, we have implemented a 2-stage model. This model co-optimizes the operation of the system and the investment in lines and storage for different scenarios of installed generation capacity. This allows us to capture the operational variability of the system and the uncertainty of the investment in the medium and long term.

The model considers investments in lines and storage as batteries and pumped storage. Due to the delay given by construction times, lines and pumped storage consider a lead time. On the other hand, the candidate batteries are installed without lead time. The lines are modelled with a transportation model, which only consider the Kirchhoff's first law. The pumped storage model allows these generators to provide energy arbitrage and upward reserves without change the state of charge. Conversely, the batteries can change the charging/discharging state to provide reserves.

The operation is simulated hourly for different weeks selected with a k-means cluster. The generators model considers a detailed operation, which includes the next constraints: ramp-up and down, minimum up and down time, maximum/minimum operating point, and upward reserves. In this vein, the operational cost of the system is given by the fuel cost, ram-up cost, start-up/shut-down cost and the value of lost load (VOLL). The reserve requirement of the system nodes can be shared with the limit of a maximum percentage of the line capacity.

3.2. Objective function

The model co-optimized the expected operational and investment cost of the electrical system in a two-stage scenario tree node as is shown in the objective function in (3.1). The investment cost considers the costs of lines and storage as pumped hydro storage (PS) and batteries along every year and scenario of the scenario tree as is shown in (3.2). The equation (3.3) shows the operational costs, which depends on different typical weeks repeated W_ω within one year. The operational costs included are the following: fuel, ramping, starting up, shutting down, upward reserves and VOLL. The downward reserves are less expensive [24], [37]; therefore, have not been considered in the formulation of the problem.

$$Min\left\{\sum_{m\in M}\phi_m \frac{(I_m+O_m)}{(1+r)^{yr_m-y^0}}\right\} \quad (3.1)$$

$$I_m=\sum_{n\in N}\left(\sum_{p\,\in\,\widehat{PS}_n}\Pi^{PS}_{p,m}\cdot\mu^{PS}_{p,m}+\sum_{b\,\in\,\hat{B}_n}\Pi^{B}_{b,m}\cdot\mu^{B}_{b,m}+\sum_{l\,\in\,\hat{L}_n}\Pi^{L}_{l,m}\cdot\mu^{L}_{l,m}\right) \quad (3.2)$$

$$O_m=\sum_{\omega\,\in\,\Omega_m}W_\omega\left(\sum_{n\in N}\left(\sum_{t\,\in\,T}\left(\sum_{g\in G_n}\left(C^{fuel}_{g,m}\cdot P_{t,g}+C^{rp}_{g}\cdot rp_{t,g}+C^{up}_{g}\cdot up_{t,g}+C^{sd}_{g}\cdot sd_{t,g}+C^{R}_{g}\cdot R_{t,g}\right)+Voll\cdot Pf_{t,n}\right)\right)\right) \quad (3.3)$$

3.2.1. Investment constraints

The construction times of the lines and PS make it impossible for these technologies to be installed immediately. In order to consider the construction time of lines and PS, the model considers a lag of one epoch (5-year period) to build lines and PS. For this reason, these technologies cannot be installed in the first epoch as it is shown in (3.4) and (3.5). Furthermore, due to the lag of one epoch, the investment in the sibling nodes must be the same for lines and PS, these constraints are shown in (3.6) and (3.7), respectively.

The model chooses the number of candidate batteries and lines to install, which are constrained in (3.8) and (3.9), respectively. Moreover, these variables are integer as is shown in (3.10). On the other hand, the PS decision is about installing the project or not; hence, it is a binary variable as is shown in (3.11).

$$\mu^{L}_{l,1}=0\ \ \forall\, l\in\hat{L}_n, n\in N \quad (3.4)$$

$$\mu^{PS}_{p,1}=0\ \ \forall\, p\in\widehat{PS}_n, n\in N \quad (3.5)$$

$$\mu^{L}_{l,m}=\mu^{L}_{l,m'}\ \ \forall\, l\in\hat{L}_n, n\in N, \forall\, m,m'\in M^s\mid m\neq m' \quad (3.6)$$

$$\mu^{PS}_{p,m}=\mu^{PS}_{p,m'}\ \forall\, p\in\widehat{PS}_n, n\in N, \forall\, m,m'\in M^s\mid m\neq m' \quad (3.7)$$

$$0\le\mu^{B}_{b,m}\le\bar{\mu}^{B}_{b}\ \ \forall\, b\in\ \hat{B}_n, n\in N, m\in M \quad (3.8)$$

$$0 \leq \mu_{l,m}^{L} \leq \bar{\mu}_{l}^{L} \;\; \forall\, l \in \hat{L}_n, n \in N, m \in M \tag{3.9}$$

$$\mu_{l,m}^{L}, \mu_{b,m}^{B} \in \mathbb{Z}^{+} \;\forall\, b \in \hat{B}_n, l \in \hat{L}_n, n \in N, m \in M \tag{3.10}$$

$$\mu_{p,m}^{PS} \in \{0,1\} \;\forall\, p \in \widehat{PS}_n, n \in N, m \in M \tag{3.11}$$

3.2.2. Supply-demand balance constraint

Equation (3.12) balances electricity supply and demand in all time t. This equation includes the power of each generator, charge and discharge of storage system, renewable production, the flow from lines and the curtailed load.

$$\begin{aligned}\sum_{g \in G_n} P_{t,g} + \sum_{b \in \{B_n, \hat{B}_n\}} \left(P_{t,b}^{d} - P_{t,b}^{ch}\right) + \sum_{p \in \{PS_n, \widehat{PS}_n\}} \left(P_{t,p}^{d} - P_{t,p}^{ch}\right) + \sum_{\upsilon \in \Upsilon_n} Pr_{t,\upsilon} \\ + \sum_{l \in \{L_n, \hat{L}_n\}} F_{t,l} + Pf_{t,n} = D_{\omega,n,t} \;\; \forall\, \omega \in \Omega_m, t \in T, n \in N, m \in M\end{aligned} \tag{3.12}$$

3.2.3. Constraints of generators

The model of the conventional generators is given by a clustered unit commitment. This method consists in clustering units with similar technical constraints to use integer variables instead of binary variables and thus reduce the problem size [38], [39]. The maximum number of units in each generator is constrained in (3.13). The maximum and minimum power output of conventional generators are given by (3.14) and (3.15), respectively. The maximum percentage of reserve that the committed generation can supply is shown in (3.16). There is a monthly factor considered in (3.17), which limits the maximum hydro generation for each month. This factor is the capacity factor calculated for each region from the historical hydro generation obtained from [40]. In [41], the forced outage rate of the generators is considered in the operational model. Based on that, the equation (3.18) shows the unavailability of the generators, which includes the full and partial outage rate. The equation (3.19) shows the maximum generation limit considering the unavailability.

$$X_{t,g} \leq nG_g \;\forall t \in T, g \in G_n, n \in N \tag{3.13}$$

$$P_{t,g} + R_{t,g} \leq \bar{P}_g \cdot \mathcal{X}_{t,g} \;\forall t \in T, g \in G_n, n \in N \tag{3.14}$$

$$\underline{P_g} \cdot \mathcal{X}_{t,g} \leq P_{t,g} \;\; \forall t \in T, g \in G_n, n \in N \tag{3.15}$$

$$R_{t,g} \leq \rho_g \cdot \overline{P_g} \cdot \mathcal{X}_{t,g} \; \forall t \in T, g \in G_n, n \in N \tag{3.16}$$

$$P_{t,g} \leq \overline{P}_g \cdot nG_g \cdot \xi_{\omega,g} \quad \forall\, t \in T, g \in G_n^H, n \in N \tag{3.17}$$

$$\mathcal{u}_g = \mathcal{F}_g + \wp_g\left(1 - \alpha_g\right) \forall\, g \in G_n, n \in N \tag{3.18}$$

$$P_{t,g} \leq nG_{m,g} \cdot \overline{P_g}\left(1 - \mathcal{u}_g\right) \forall\, t \in T, g \in G_n, n \in N \tag{3.19}$$

The number of online units is given by the generator starting up minus generators shutting down as is shown in (3.20). Constraints (3.21)-(3.24) impose minimum up and down times, which guarantee that the generators switched on/off must remain in that state for a minimum time.

$$\mathcal{X}_{t,g} = \mathcal{X}_{t-1,g} + up_{t,g} - dw_{t,g} \qquad \forall\, t > 1 \in T, g \in G_n, n \in N \tag{3.20}$$

$$\mathcal{X}_{t,g} \geq \sum_{t' \in \{1:t\}} up_{t',g} \qquad if \;\; t \leq Ut_g \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.21}$$

$$\mathcal{X}_{t,g} \geq \sum_{t' \in \{t-Ut_g:t\}} up_{t',g} \qquad t > Ut_g \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.22}$$

$$nG_{m,g} - \mathcal{X}_{g,t} \geq \sum_{t' \in \{1:t\}} sd_{g,t'} \qquad if \;\; t \leq Dt_g \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.23}$$

$$nG_{m,g} - \mathcal{X}_{g,t} \geq \sum_{t' \in \{t-Dt_g:t\}} sd_{g,t'} \qquad t > Dt_g \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.24}$$

The conventional technologies have a maximum ramp rate limit. These constraints are shown in (3.25) and (3.26). Besides, the ramp must be calculated to add the value to the objective function, this is done in (3.27) and (3.28).

$$P_{t,g} - P_{t-1,g} \leq \mathcal{X}_{t-1,g} \cdot Ramp_g \cdot \overline{P_g} + up_{t,g} \cdot \underline{P_g} \;\; \forall\, t \in T, g \in G_n, n \in N \tag{3.25}$$

$$P_{t-1,g} - P_{t,g} \leq \mathcal{X}_{t,g} \cdot Ramp_g \cdot \overline{P_g} + sd_{t,g} \cdot \underline{P_g} \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.26}$$

$$P_{t,g} - P_{t-1,g} - up_{t,g} \cdot \underline{P_g} \leq Rp_{t,g} \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.27}$$

$$P_{t-1,g} - P_{t,g} - sd_{t,g} \cdot \underline{P_g} \leq Rp_{t,g} \quad \forall\, t \in T, g \in G_n, n \in N \tag{3.28}$$

The renewable output is constrained in (3.29) by the install capacity and the profiles for wind and solar resource in the week ω.

$$Pr_{t,v} \leq \overline{Pr}_{m,v} \cdot Pl_{\omega,v,t} \; \forall\, t \in T, v \in \Upsilon_n, n \in N \tag{3.29}$$

3.2.4. Existing storage

The existing storage plants consider two technologies: PS and residential batteries grouped as virtual power plant (VPP). The storage models are based on [42]. Both technologies can provide energy arbitrage, and PS can also supply reserves.

The energy balance of the storage plants is calculated in (3.30). Equation (3.31) shows the energy available in the PS plants to provide reserves in the next hour. The maximum energy that can be stored is constrained in (3.32). The power balance of VPP and PS are shown in (3.33) and (3.34), respectively. The charging (3.35) and discharging (3.36) of storage plants are defined considering binary variables (3.37) and the maxim power output.

$$E_{t,s} = P_{t,s}^{ch} \cdot \eta_s^{ch} - \frac{P_{t,s}^{d}}{\eta_s^{d}} + E_{t-1,s} \; \forall\, t > 1 \in T, s \in S_n, n \in N \tag{3.30}$$

$$R_{t,p}^{E} \cdot \psi_p \leq E_{t-1,p} \quad \forall\, t > 1 \in T, \forall\, p \in PS_n, n \in N \tag{3.31}$$

$$E_{t,s} \leq \bar{E}_s \qquad \forall\, t \in T, s \in S_n, n \in N \tag{3.32}$$

$$P_{t,b}^{d} - P_{t,b}^{ch} \leq \bar{P}_b^{E} \qquad \forall\, t \in T, b \in B_n, n \in N \tag{3.33}$$

$$P_{t,p}^{d} - P_{t,p}^{ch} + R_{t,p}^{E} \leq \bar{P}_p^{E} \cdot X_{t,p} \quad \forall\, t \in T, p \in PS_n, n \in N \tag{3.34}$$

$$P_{t,s}^{ch} \leq (1 - X_{t,s})\bar{P}_s^{E} \quad \forall\, t \in T, s \in S_n, n \in N \tag{3.35}$$

$$P_{t,s}^{d} \leq X_{t,s} \cdot \bar{P}_{s}^{E} \quad \forall\, t \in T, s \in S_n, n \in N \tag{3.36}$$

$$X_{t,s} \in \{0,1\} \;\; \forall\, s \in \; S_n, n \in N, m \in M \tag{3.37}$$

3.2.5. Candidate storage

The energy balance of the candidate storage plants is calculated in (3.38). The equation (3.39) show the energy available to provide reserves in the next hour. The maximum amount of energy is constrained in (3.40), which depends on the investment in storage. The power balance of batteries and PS are shown in (3.41) and (3.42), respectively. The charging and discharging power of batteries are constrained by its state of charge and a big number $\bar{M}$ in (3.43) and (3.44). Similarly, the maximum charge and discharge of PS are shown in (3.45) and (3.46). The equations (3.47) and (3.48) constraint the charge/discharge of the candidate PS and batteries considering the investment variables.

$$E_{t,s} = P_{t,s}^{ch} \cdot \eta_{s}^{ch} - \frac{P_{t,s}^{d}}{\eta_{s}^{d}} + E_{t-1,s} \quad \forall t > 1 \in T, s \; \in \hat{S}_n, n \in N \tag{3.38}$$

$$R_{t,s}^{C} \cdot \psi_{s} \leq E_{t-1,s} \quad \forall\, t > 1 \in T, s \; \in \hat{S}_n, n \in N \tag{3.39}$$

$$E_{t,s} \leq \bar{E}_{s}^{C} \cdot \mu_{s,m}^{B/PS} \quad \forall\, t \in T, s \; \in \hat{S}_n, n \in N \tag{3.40}$$

$$P_{t,b}^{d} - P_{t,b}^{ch} + R_{t,b}^{C} \leq \bar{P}_{b}^{C} \cdot \mu_{b,m}^{B} \;\; \forall\, t \in T, b \in \hat{B}_n, n \in N \tag{3.41}$$

$$P_{t,p}^{d} - P_{t,p}^{ch} + R_{t,p}^{C} \leq \bar{P}_{p}^{C} \cdot X_{t,p} \quad \forall\, t \in T, p \in \widehat{PS}_n, n \in N \tag{3.42}$$

$$P_{t,b}^{ch} \leq \left(1 - X_{t,b}\right)\bar{M} \;\; \forall\, t \in T, b \in \hat{B}_n, n \in N \tag{3.43}$$

$$P_{t,b}^{d} \leq X_{t,b} \cdot \bar{M} \;\; \forall\, t \in T, b \in \hat{B}_n, n \in N \tag{3.44}$$

$$P_{t,p}^{ch} \leq \left(1 - X_{t,p}\right)\bar{P}_{p}^{C} \quad \forall\, t \in T, p \in \widehat{PS}_n, n \in N \tag{3.45}$$

$$P_{t,p}^{d} \leq X_{t,p} \cdot \bar{P}_{p}^{C} \quad \forall\, t \in T, p \in \widehat{PS}_n, n \in N \tag{3.46}$$

$$P_{t,s}^{ch} \leq \bar{P}_s^C \cdot \mu_{s,m}^{B/PS} \quad \forall\, t \in T, s \in \hat{S}_n, n \in N \tag{3.47}$$

$$P_{t,s}^{d} \leq \bar{P}_s^C \cdot \mu_{s,m}^{B/PS} \quad \forall\, t \in T, s \in \hat{S}_n, n \in N \tag{3.48}$$

$$X_{t,s} \in \{0,1\} \;\; \forall\, s \in \hat{S}_n, n \in N, m \in M \tag{3.49}$$

3.2.6. Reserves

The reserve requirement is the minimum level of firm capacity for each region. These reserves are sufficient to meet reliability requirements, covering approximately the largest single generating unit. The reserve balance is shown in (3.50). The technologies allowed to provide reserves in the balance are the following: conventional generator, existing PS, candidate storages as batteries and PS, and reserves coming from other nodes of the system.

$$R_{t,n}^0 = \sum_{g \in G_n} R_{t,g} + \sum_{p \in PS_n} R_{t,p}^E + \sum_{b\, \in \hat{B}_n} R_{t,b}^C + \sum_{p\, \in\, \widehat{PS}_n} R_{t,p}^C + \sum_{l\, \in\, L_n} (Fr_{t,l}^{fw} - Fr_{t,l}^{rv}) \;\; \forall\, t \in T, n \in N \tag{3.50}$$

3.2.7. Line flow

We implemented a transportation model for lines. The maximum and minimum line flows are shown in (3.51) and (3.52), respectively. Both equations consider that the reserves can be imported/exported among the different states. The maximum imported/exported reserves in the line l are limited by a factor $\overline{Fr_l}$ as is shown in (3.53) and (3.54). This factor defines the percentage of the line capacity used to share reserves in the line l.

$$F_{t,l} + Fr_{t,l}^{fw} \leq \bar{F}_l + \mu_{l,m}^{L} \cdot \bar{L}_l \;\forall\, t \in T, l \in L_n, n \in N \tag{3.51}$$

$$-(\bar{F}_l + \mu_{l,m}^{L} \cdot \bar{L}_l\,) \leq F_{t,l} - Fr_{t,l}^{rev} \;\; \forall\, t \in T, l \in L_n, n \in N \tag{3.52}$$

$$0 \leq Fr_{t,l}^{fw} \leq \overline{Fr_l}(\bar{F}_l + \mu_{l,m}^{L} \cdot \bar{L}_l) \quad \forall\, t \in T, l \in L_n, n \in N \tag{3.53}$$

$$0 \leq Fr_{t,l}^{rev} \leq \overline{Fr_l}(\bar{F}_l + \mu_{l,m}^{L} \cdot \bar{L}_l) \quad \forall\, t \in T, l \in L_n, n \in N \tag{3.54}$$

Chapter 4

Case study

4.1. Input data

The NEM is comprised of five regions: Victoria (VIC), Tasmania (TAS), South Australia (SA), New South Wales (NSW) and Queensland (QLD). These regions are represented in the 5-nodes model shown in FIGURE 4.1. The figure shows the candidate investments for lines and storages, as PS and batteries.

The storage properties of the candidate plants are shown in TABLE 4.1. The PS projects includes are: Snowy 2.0 in NSW and Battery of the Nation (BON) in TAS. The cost of these projects are 5733 MMA$ [43] and 2805 MMAU$ [44], respectively. TABLE 4.2 shows the current capacity of the lines, the candidate lines, the cost of these projects [45] and the maximum number of candidates lines allowed.

The implemented model considers 4 types of conventional generation technologies: open cycle gas turbine (OCGT), combined cycle gas turbine (CCGT), coal and hydro. These technologies are approximately 250 dispatchable generators in the NEM [46]. To reduce the computational burden the unit commitment of these generators has been included through a clustered unit commitment. The implemented clustered unit commitment amount 40 generators in the reduced system. These generators were chosen with a k-means cluster, selecting between 2 and 5 generators per technology in each bus.

TABLE 4.3 shows technical details (maximum ramp rate, minimum power output, unavailability, among others) for conventional technologies. The cost details of thermal generators are given in TABLE 4.4, in which we show the ramping, starting-up and reserve cost, which are based on [47],[48] and [49], respectively. The fuel cost is based on [45] and depends on the technology, region and year.

The VOLL is 15.000 [A$/MWh] [50]. The discount rate applied is 6.3% given by the average value of AEMO's discount rates [45]. The reserve requirements for each region are shown in TABLE 4.5 [45]. The model considerers that the reserves can be imported/exported between two nodes, using a top up of 50% of line capacity for all the lines. The conventional generation can provide up to 10% of committed generation as reserve. The model also considers that VPPs do not supply reserves. VPP and candidate batteries have 81% round-trip efficiency and PSs have 75.7% round-trip efficiency.

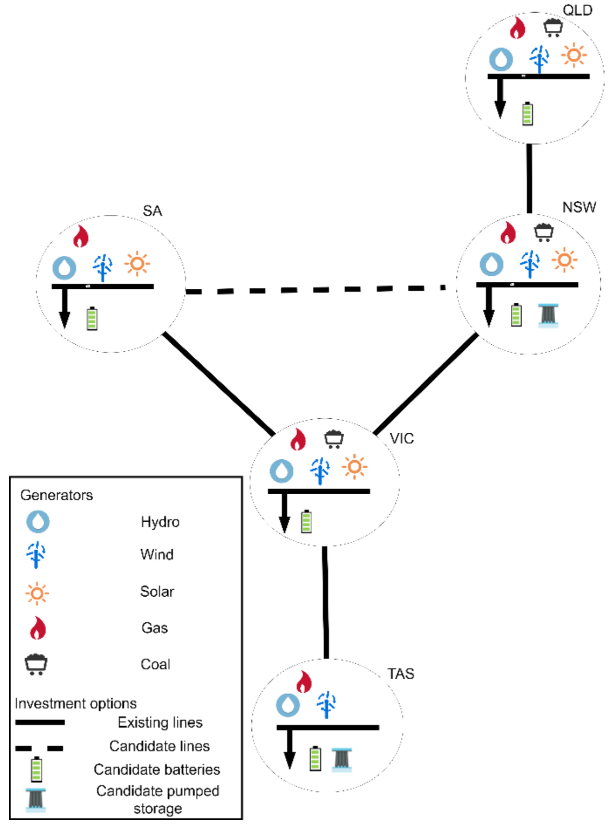


Figure 4.1 5-node model NEM.

Location	Storage	Properties
All nodes	Battery	200 MW - 2 hours
TAS	PS	1700 MW - 21.6 hours
NSW	PS	2000 MW - 168 hours

Table 4.1 Storage investment options.

Investment options	Existing lines [MW]	Candidate lines [MW]	Maximum number of candidate lines	Cost [A$/MW]
SA-NSW	0	800	1	2487500
SA-VIC	850	200	20	1986000
VIC-TAS	480	750	2	2487125
VIC-NSW	700	200	18	2066343
NSW-QLD	950	200	30	1808614

Table 4.2 Current line capacities, candidate lines and maximum number of candidates.

Technology	Maximum ramp rate [% of maximum capacity]	Minimum power output [% of maximum capacity]	Unavailability [%]	Heat rates [GJ/MWh]	Start-up time [h]	Shut-down time [h]
CCGT	90	30	1.91	11.28	5	1
OCGT	50	10	2.72	24.63	6	1
Coal	25	40	19.77	11.49	10	4
Hydro	100	0	2.34	-	0	0

Table 4.3 Characteristics of thermal and hydro generation.

Technology	Ramping cost [A$/ΔMW]	Start-up cost [A$/MW]	Reserve cost [% of fuel cost]
CCGT	0.25	15	1.49
OCGT	1.21	100	1.74
Coal	3.59	170	93.50

Table 4.4 Thermal generator cost.

Region	Regional Reserve Requirements [MW]
NSW	673
QLD	666
SA	273
TAS	194
VIC	498

Table 4.5 Regional reserve requirement.

4.2. Input data per scenario

To capture the uncertainty of structural drivers about the future, the development of the NEM system is addressed by a set of five scenarios: Central, Slow, High DER, Fast and Step [51]. These scenarios include different deployment of conventional generation, VREG, demand growth levels and penetration of DER resources such as the following: EV; DG, as rooftop Photovoltaic and Photovoltaic Non-scheduled generation (PVNSG); and energy storage systems (ESS), as VPP and behind-the-meter batteries. Besides, these scenarios have diverse assumptions about fuel cost and investment cost for batteries. The scenarios can be classified according to their different levels of decarbonisation and decentralisation, as is shown in FIGURE 4.2. The assumptions behind these scenarios have been based on different engineering, economic and socio-political assessments of infrastructure and resource costs following the goals for "4 -degrees" and "2-degrees" scenarios built by CSIRO [52], which according to their names describe the global climate policy targets. For the 2-degrees scenario, it is expected that the coal generation in 2050 will be close to zero, and it is also expected a low generation of gas. On the other hand, the 4 degrees scenario considers a significant amount of energy produced by coal and gas generators.

FIGURE 4.3 shows the implemented 2-stage scenario tree with 4 epochs. The tree is built with a common root node and branching in the first epoch in five equiprobable scenarios. Thus, each scenario has 3 epochs (plus the root node), where each epoch represents 5 years from 2020 to 2035.

In the following paragraphs a brief description of the scenarios based on [51] will be given:

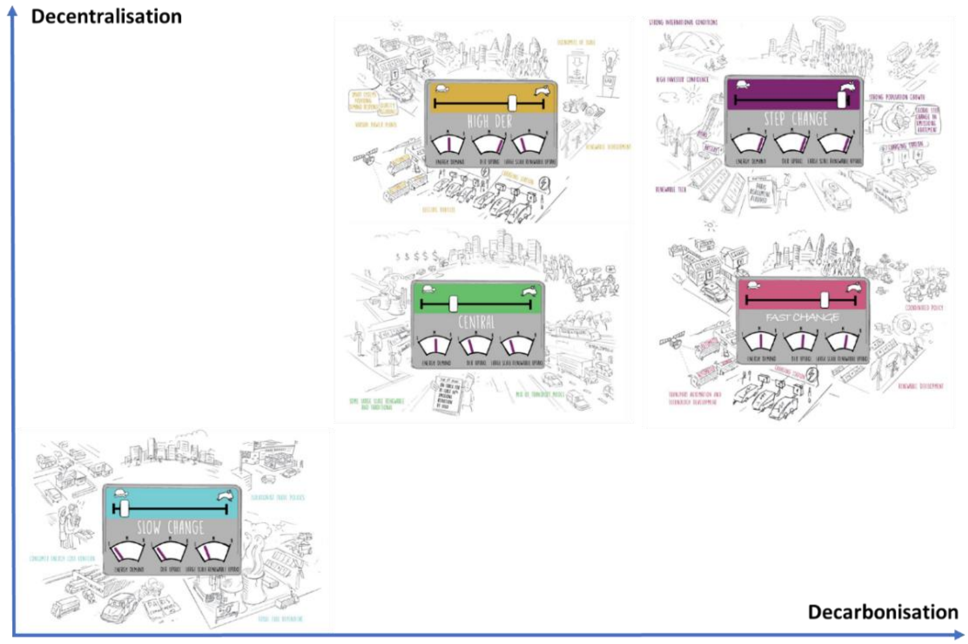


Figure 4.2 Degree of decarbonisation and decentralisation of the NEM scenarios [51].

1. Central: Central scenario is developed considering a moderate economic and population growth. The government policies keep without big changes; hence, the transition from fossil fuels to renewable generation is led by market forces, which implies following the 4-degree CSIRO scenario. This scenario also considers a moderate adoption of DER resources in the next decade, following the current development. The DER technologies included are as follows: rooftop PV, EV and ESS as behind-the-meter batteries and VPP.
2. Slow change: This scenario considers a slow economic and population growth. The government policies do not support DER; therefore, the adoption of these technologies is slower relative to the central scenario. The VREG has limited political, commercial and social support, resulting in slow changes in technology investment costs, and the changes are weaker than the 4-degree CSIRO scenario.
3. High DER: This scenario is a variant of the central scenario where the growth in EV, DG are moderate-high and in ESS is extremely high. These changes will be developed with changes in policies. The growth of VREG is a mix between 2- and 4-degree CSIRO scenarios.
4. Fast change: The economic and population growth is the same as in the central scenario. Moreover, the adoption of DG, ESS and EV are moderate-high. The adoption of VREG is high in line with the 2-degrees CSIRO scenario.
5. Step Change: This scenario includes a response to climate change. The economic and population growth is the highest. New policies are considered to drive a fast growth in all the technologies, reaching a high penetration of DG, ESS and EV.

Moreover, the VREG increment is the strongest being even higher than the projection made for the 2-degrees CSIRO scenario.

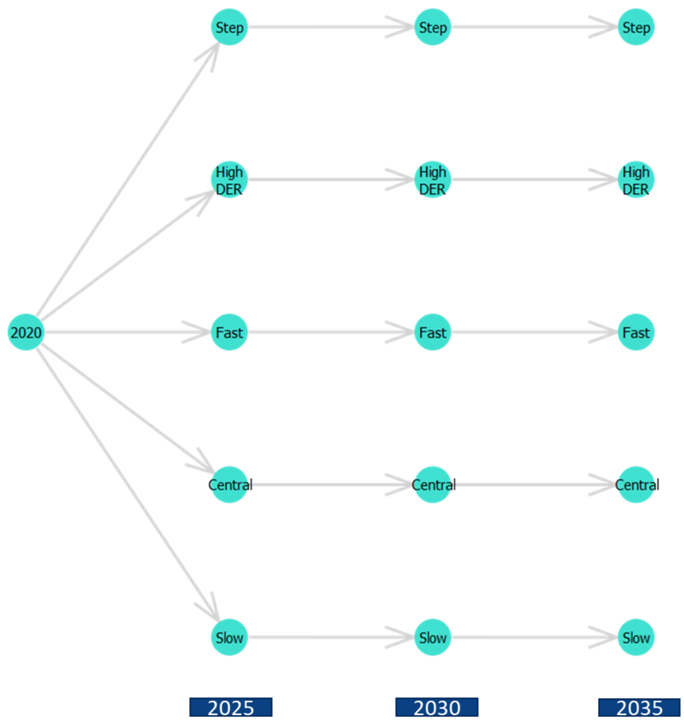


Figure 4.3 2-stage scenario tree problem.

FIGURE 4.5 shows the installed capacity of the different scenarios and technologies in the NEM for the upcoming years. In the figure, it can be seen that the installed capacity of coal decreases yearly. On the other hand, the install capacity of VREG and DER technologies increase [53].

According to market expectations, the investment cost of batteries evolves, becoming cheaper to install in future years. FIGURE 4.4 shows the overnight investment cost of a 2 hours battery storage for the different scenarios [45].In the figure Slow, Central and High DER scenarios have the same cost trajectory.

FIGURE 4.6 shows the annual energy consumptions of every scenario. These scenarios have different consumption because they include diverse penetration of EV demand, technologies development and behind-the-meter battery charge/discharge [36]. Two profiles with the same annual energy consumption and different maximum energy consumption are considered for each scenario. These profiles are called according to their POE as POE 10% and POE 50%. The MD of the POE 10% profile is expected to be exceeded on average one year in ten, and the MD of the POE 50% is expected to be exceeded one year in two [36]. FIGURE 4.7 shows the MD of the POE 10% and POE 50% profiles for the Central scenario in the NEM system (a) and NSW (b), which is the node with the highest demand.

To reduce the computational burden weekly profiles with an hourly resolution have been selected. The weeks with the MD were added to the model and the remaining weeks were chosen with a k-means method focused on the NEM demand. To check the quality of the results the root mean square error was calculated comparing the resultant demand curve with the original [54]. By selection 12 weeks, the maximum errors for the NEM and a single node are 5.9% and 9.2%, respectively.

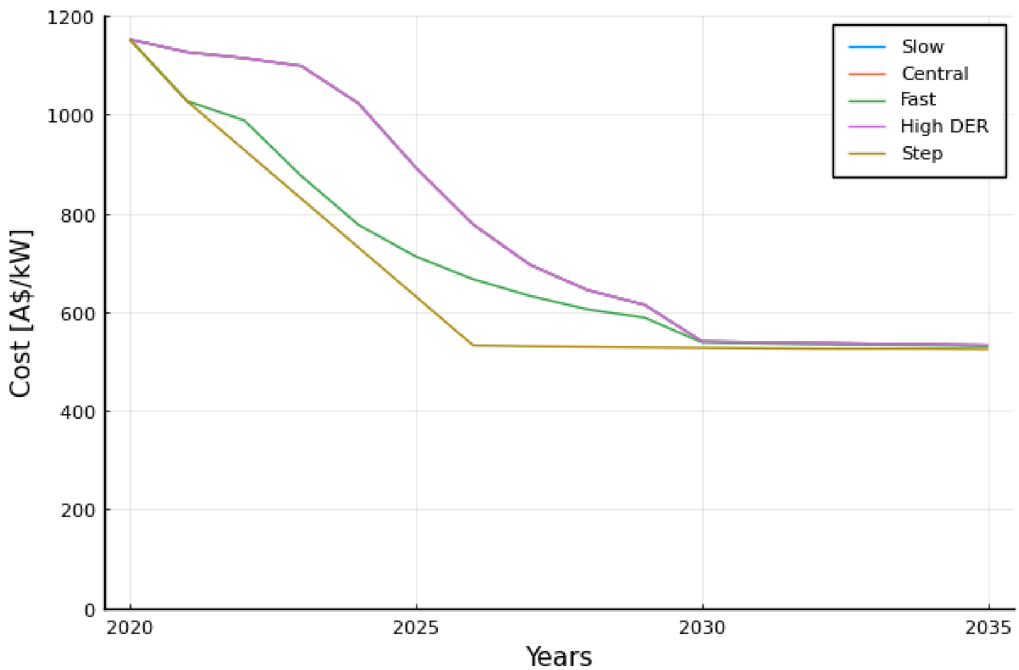


Figure 4.4 Battery investment cost per kW by scenario.

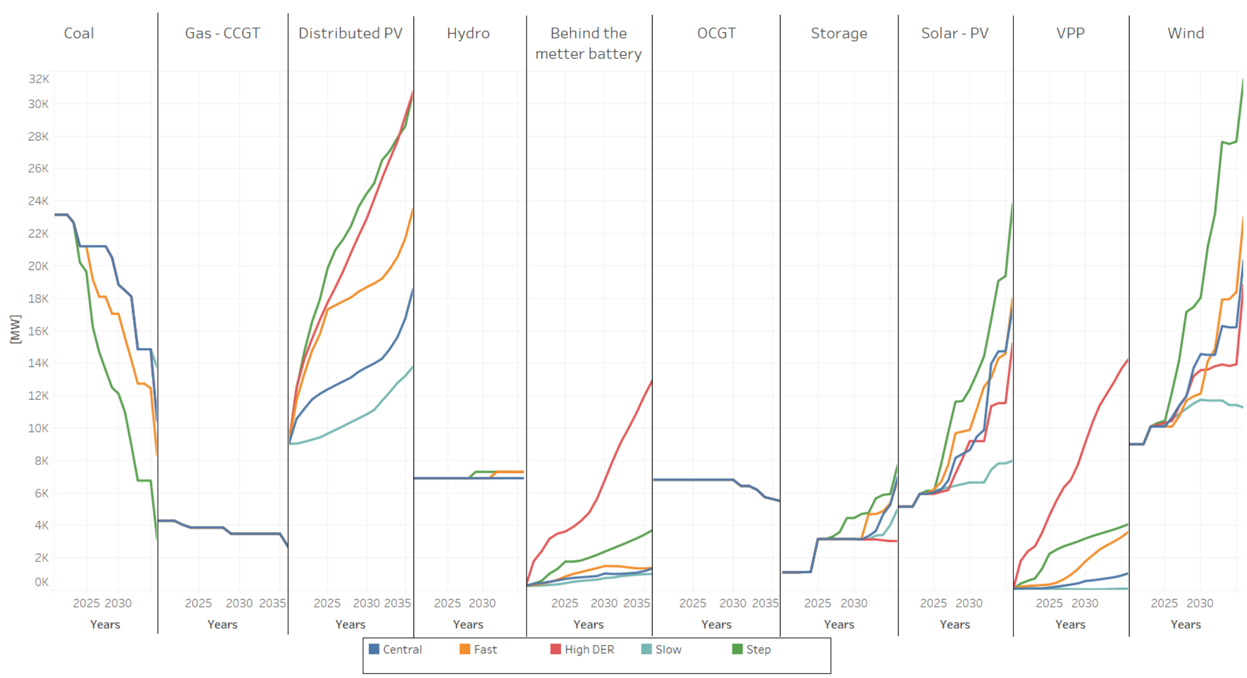


Figure 4.5 Installed capacity of NEM technologies for different scenarios.

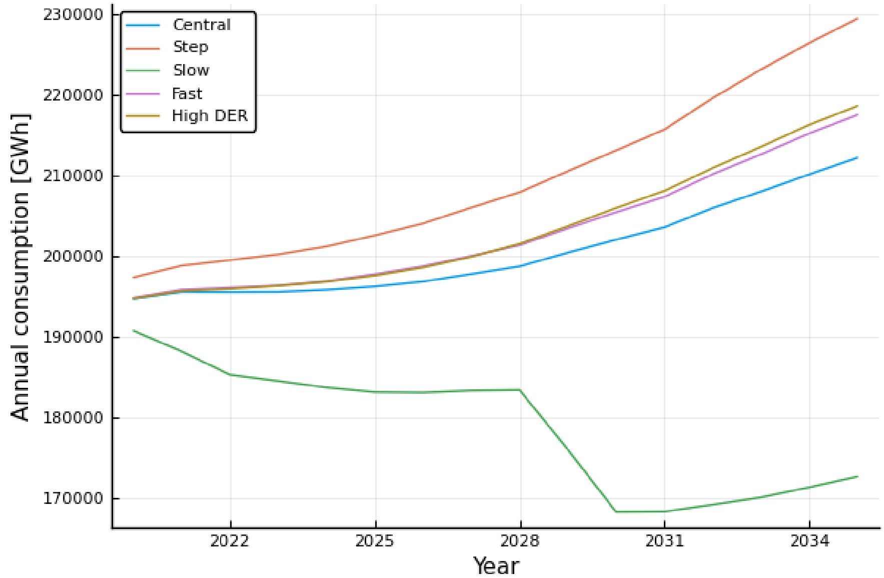
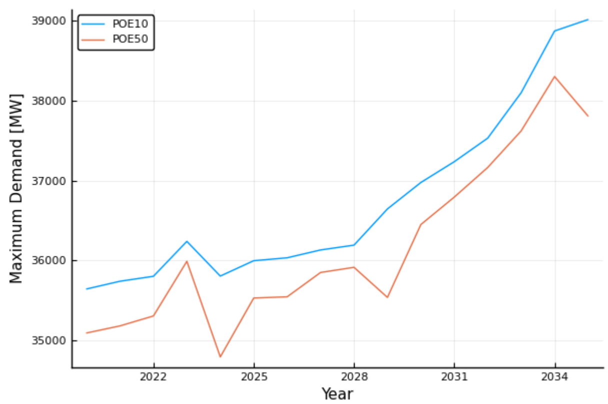
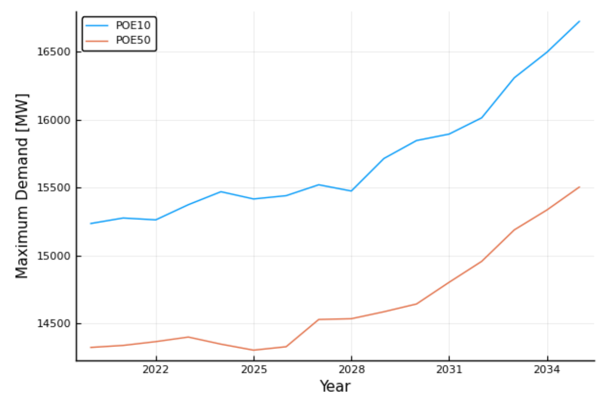


Figure 4.6 Annual consumption of the different scenarios



(a)



(b)

Figure 4.7 MD in Central scenario for POE 10% and POE 50 %. (a) NEM system; (b) NSW.

Chapter 5

Results and discussion

The results are divided into four sections, where each section shows a different case described in TABLE 5.1. The base case is solved with a stochastic approach considering the MD of the POE 10%. The case 1 is solved with a deterministic approach with the same POE than the base case. The cases 2 and 3 are solved with a stochastic approach. Moreover, the case 2 does not consider batteries in the investment options, and the case 3 considers the MD of the POE 50%. All cases consider 12 weeks of operation selected with a k-means cluster.

The case study was coded in Julia 0.6, solved with Gurobi 8.1, and ran on a cluster, coordinating 19 8-core i7 Intel machines with 16 GB of RAM each. The optimization was implemented with a Dantzig-Wolfe decomposition with a column generation algorithm developed in [22], [55]. This decomposition splits the investment and the operation of the system in two problems: The master problem and a set of slave problems. The slave problems solve in parallel the hourly operation of the different weeks for each iteration of the master problem. On the other hand, the master problem minimizes the operational cost of the different slaves and the investment cost. By doing this, the computational burden decreases [22], [55], [56]. The problem requested an optimal MIP gap of 0.5%. The time needed to obtain results under the gap was between 9 hours in the no batteries case and 19 hours in the base case. The resolution time is out the scope of this thesis; therefore, these results will not be discussed.

Case	POE	Others
Base case: POE 10	10	-
Case 1: Deterministic	10	-
Case 2: No Batteries	10	The optimization does not consider batteries in the storage options.
Case 3: POE 50	50	-

Table 5.1 Case descriptions.

5.1. Base case: POE 10

Tables 5.2-5.4 show the optimal portfolio of lines, batteries and PS. The line results show that the investment in the NSW-VIC and QLD-NSW lines are deployed in the second epoch with 800 MW and 600 MW, respectively. The requirement of these lines increases over the years depending on the scenario. Moreover, the TAS-VIC line is deployed in the Central, Fast and High DER scenarios with 750 MW in the last epoch, as well as the Step scenario with 750 MW and 1500 MW for the third and fourth epoch, respectively. The SA-NSW line is also required in the last epoch of the Step scenario.

The battery deployment starts in the first epoch to decrease the energy not supplied (ENS) in the MD. These batteries are installed in SA and NSW, installing 200 MW in each region. In the second epoch, the battery investments in NSW are 600 MW, 1000MW, 1200 MW, 400 MW and 2000 MW for the Slow, Central, Fast, High DER and Step scenarios, respectively. These investments are made to complement the investment in the NSW-VIC and QLD-NSW lines. Regarding the total number of installed batteries, the Step scenario installs a total amount of 24600 MW. It is followed by Central and Fast scenarios, which invest in 12800 MW and 11200 MW, respectively. The scenarios with the lowest number of batteries are Slow and High DER with 9000 MW and 2600 MW. The Slow scenario needs a low number of batteries because this scenario has the lowest annual energy consumption and the minimum MD. On the other hand, the High DER scenario has the highest penetration of behind-the-meter batteries and a high penetration of EV, which makes its demand challenging in the peak hours. Nevertheless, the investment in batteries is low because the penetration of VPPs in this scenario is the highest, which decrease the requirement of batteries and PS.

Regarding the investment in PS, the first PS deployed is Snowy in NSW. This PS is required in the third epoch for Fast and Step scenarios and in the last epoch for Central and High DER scenarios. BON in TAS is deployed at the same time as the line between TAS and VIC for the Central, Fast and Step scenarios. These investments are made at the same time to evacuate the excess of renewable resources from TAS to the NEM system.

Location	Scenario	2020 [MW]	2025 [MW]	2030 [MW]	2035 [MW]
TAS–VIC	Slow	0	0	0	0
	Central	0	0	0	750
	Fast	0	0	0	750
	High DER	0	0	0	750
	Step	0	0	750	1500
NSW–VIC	Slow	0	800	800	800
	Central	0	800	800	800
	Fast	0	800	800	800
	High DER	0	800	1200	1200
	Step	0	800	800	800
QLD-NSW	Slow	0	600	600	1400
	Central	0	600	1400	2800
	Fast	0	600	800	1800
	High DER	0	600	800	1800
	Step	0	600	600	2000
SA-VIC	Slow	0	0	0	0
	Central	0	0	0	0
	Fast	0	0	0	0
	High DER	0	0	0	0
	Step	0	0	0	0
SA-NSW	Slow	0	0	0	0
	Central	0	0	0	0
	Fast	0	0	0	0
	High DER	0	0	0	0
	Step	0	0	0	800

Table 5.2 Line investment results – base case. The results are shown as accumulated installed investment.

Location	Scenario	2020 [MW]	2025 [MW]	2030 [MW]	2035 [MW]
TAS	Slow	0	0	0	0
	Central	0	0	0	0
	Fast	0	0	0	0
	High DER	0	0	0	0
	Step	0	0	0	0
SA	Slow	200	200	400	1600
	Central	200	200	1000	1200
	Fast	200	200	1000	2200
	High DER	200	200	400	600
	Step	200	200	1400	1800
VIC	Slow	0	200	200	200
	Central	0	0	1200	1200
	Fast	0	0	0	0
	High DER	0	0	0	0
	Step	0	0	1800	2000
NSW	Slow	200	600	2000	7000
	Central	200	1000	3200	3200
	Fast	200	1200	2200	3000
	High DER	200	400	1200	1200
	Step	200	2000	2000	5200
QLD	Slow	0	0	200	200
	Central	0	0	2000	7200
	Fast	0	0	0	6000
	High DER	0	0	0	800
	Step	0	0	2600	15600

Table 5.3 Battery investment results – base case. The results are shown as accumulated installed investment.

Location	Scenario	2020	2025	2030	2035
NSW	Slow	0	0	0	0
	Central	0	0	0	1
	Fast	0	0	1	1
	High DER	0	0	0	1
	Step	0	0	1	1
TAS	Slow	0	0	0	0
	Central	0	0	0	1
	Fast	0	0	0	1
	High DER	0	0	0	0
	Step	0	0	0	1

Table 5.4 Pumped storage results – base case. The results are shown as accumulated installed investment, where 1 means the PS project is installed.

5.2. Case 1: Deterministic

TABLE 5.5 and 5.6 show the difference between the investment in lines and batteries with respect to the investment in the base case. What stands out in these tables are the different line investments, where each scenario has its own optimal solution, which is different of the other line investment. From the tables, it can be seen that the investments of the second epoch in NSW-VIC is 600 MW lower for the Slow scenario and it is 200 MW higher for the High DER and Step scenarios. Moreover, the investments in QLD-NSW are 200 MW higher in the second epoch for Slow, Central and Fast scenarios. It is in the different line investments when it can be seen the value of the stochastic planning, which helps to reach a new optimal in the different solutions by investing in batteries.

Although the investments in batteries in the first epoch are the same as in the base case, the investments in the second epoch are different for all scenarios. On the one hand the battery investment is higher in the Slow scenario due to the lower investment in lines in this scenario. On the other hand, the battery investments for Central, Fast and Step scenarios are lower than in the base case. The lower battery investments for the deterministic case are due to the higher investment in lines in NSW, which increase the power generated by the conventional generation in the hours of high demand. In fact, the higher investment of QLD-NSW increases the power output of the conventional generators in QLD, which is send to NSW in the high demand hours. Similarly, the higher investment in NSW-VIC increases the power output of conventional generators in VIC. In contrast, the additional batteries in the stochastic results allow the model to provide energy arbitrage in the high demand hours. Therefore, the stochastic approach invests in more batteries in the scenarios with challenging demand to defers line investment. This decreases the energy produced by conventional generators.

Finally, the investments in PS are the same as in the base case because these investments are made in the last epochs, and the stochasticity introduced in the second epoch does not impact such epochs.

Location	**Scenario**	**2020** [MW]	**2025** [MW]	**2030** [MW]	**2035** [MW]
NSW - VIC	Slow	0	-600	-400	-400
	High DER	0	200	-200	0
	Step	0	200	200	200
QLD - NSW	Slow	0	200	200	200
	Central	0	200	200	0
	Fast	0	200	0	0
	High DER	0	0	200	200
SA - NSW	Step	0	0	0	-800

Table 5.5 Line results – deterministic. The results are shown as the difference between the base case and deterministic case.

Location	**Scenario**	**2020** [MW]	**2025** [MW]	**2030** [MW]	**2035** [MW]
TAS	Slow	0	0	0	200
	High DER	0	0	0	200
SA	Fast	0	0	0	-400
	High DER	0	0	0	-200
	Step	0	0	0	1000
VIC	Slow	0	-200	200	400
	Step	0	0	-200	-400
NSW	Slow	0	400	200	-400
	Central	0	-200	-200	-200
	Fast	0	-200	0	200
	High DER	0	200	-200	-200
	Step	0	-400	-400	-800
QLD	Slow	0	0	200	200
	Central	0	0	0	-200
	Fast	0	0	0	-1600
	High DER	0	0	200	-200
	Step	0	0	400	0

Table 5.6 Battery results – deterministic. The results are shown as the difference between the base case and deterministic case.

TABLE 5.7 summarises the total costs per scenario and the expected total costs of the deterministic and stochastic solutions. The total cost of the stochastic solution is higher than the best solution in the deterministic scenario. In fact, the stochastic solutions are between 0.02 % and 0.38% above the best solution of the deterministic scenarios. On the other hand, the worst deterministic solutions are between 7.75% and 64.32% more expensive than the stochastic solution. Regarding, the expected total cost of the stochastic solution, it is between 3.5% and 36.09% cheaper than the deterministic solutions. Therefore, the stochastic solution leads to a cheaper total system cost.

Figure 5.1 shows the expected investment cost, and figure 5.2 shows the expected operational cost. Both figures show the stochastic and deterministic costs. In the figures, the deterministic solution for the Slow, Fast and Step scenarios invest less than the stochastic solution, having a higher operational cost. On the other hand, High DER and Central scenarios invest earlier and more in the deterministic solution to save in the operational cost.

Total cost per scenario [MMA$]	Deterministic solution for Slow scenario	Deterministic solution for Central scenario	Deterministic solution for Fast scenario	Deterministic solution for High DER scenario	Deterministic solution for Step scenario	Base case (Stochastic solution)
Slow	7019	7251	7282	7163	7637	7045
Central	13529	9198	9367	11433	9513	9205
Fast	10075	8306	8201	9213	8460	8210
High DER	7577	7511	7519	7263	7914	7264
Step	25889	10182	10520	18097	9225	9237
Expected total cost [MMA$]	12818	8489	8578	10634	8550	8192

Table 5.7 Total cost per scenario and expected total costs of the deterministic and stochastic solutions.

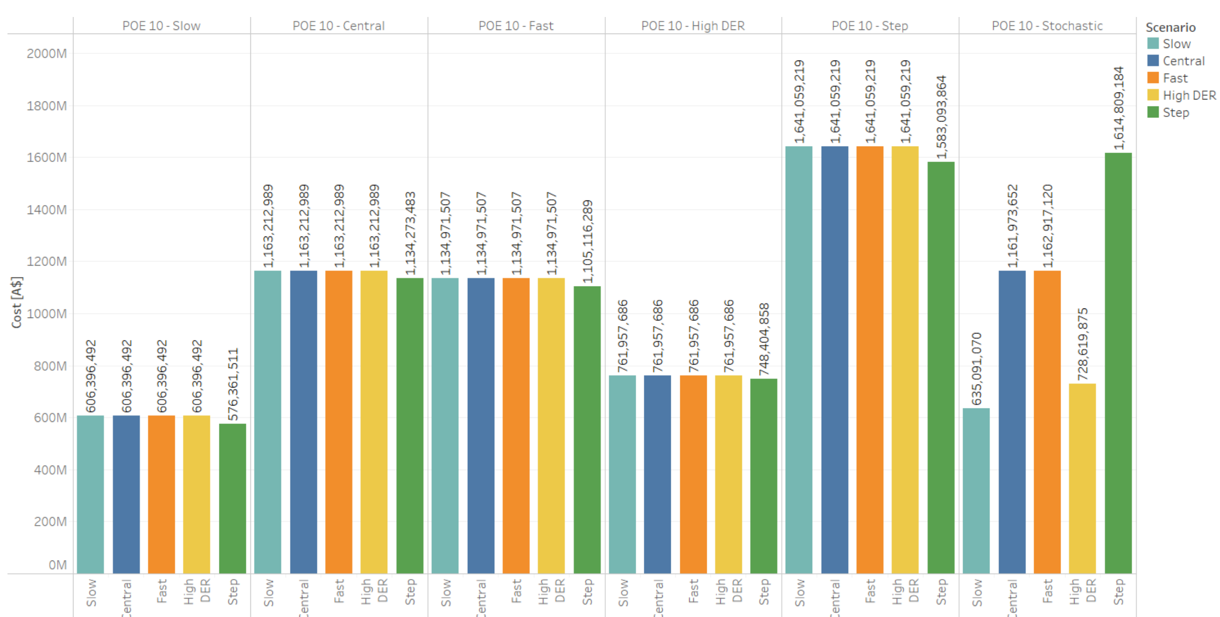


Figure 5.1 Expected investment cost for deterministic and stochastic solutions.

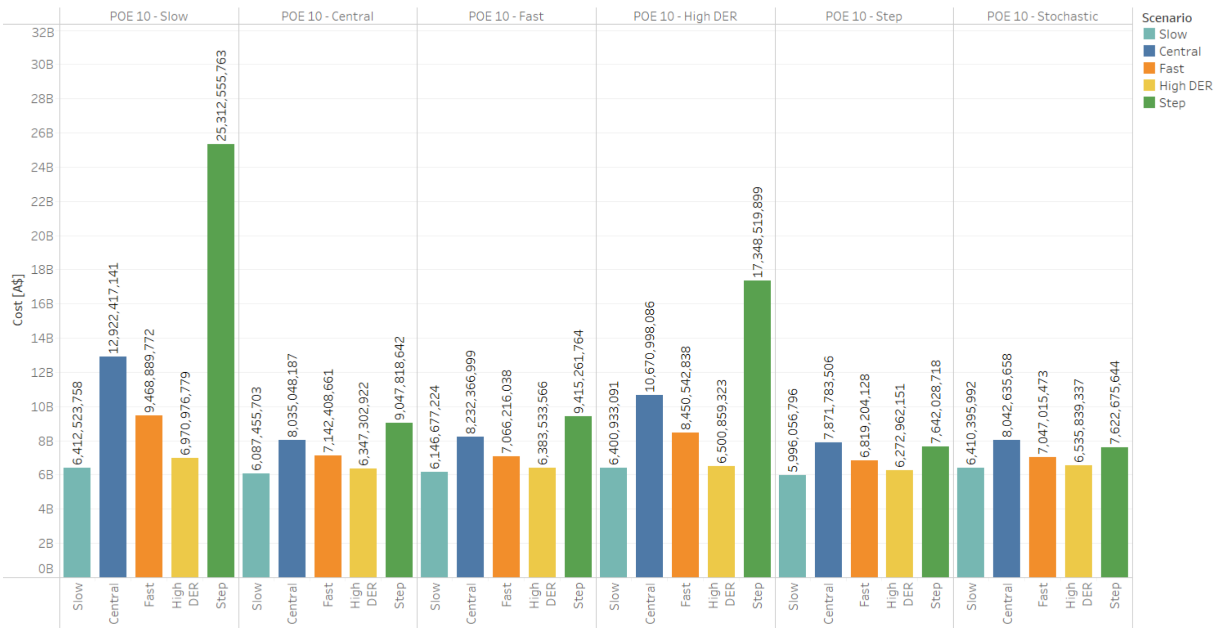


Figure 5.2 Expected operational cost of deterministic and stochastic solutions.

5.3. Case 2: No batteries

Table 5.8 and 5.9 show the difference with respect to the investment in the base case for lines and PS, respectively. By not considering batteries, the investments in the second epoch of NSW-VIC and QLD-NSW lines are 200 MW higher. These additional investments show a deferral effect in the line investments by investing in batteries with a stochastic formulation. In the following epochs, the line investments are higher than the base case for all the candidate lines. For instance, it is required the investment of SA-NSW line in the Central and Fast scenarios in the last two epochs. Similarly, SA-VIC line is installed in the last two epochs of the Slow, High DER and Step scenarios. Moreover, the investment in TAS-VIC increases 750 MW in the third epoch of the Step scenario and in the fourth epoch of the Central and Fast scenario. Regarding the investment in PS, Snowy and BON are deployed one epoch earlier in the Central and Step scenarios, respectively. Moreover, Snowy is also installed in the last epoch of the Slow scenario.

Comparing the results with and without batteries, it can be identified one additional effect in the third epoch of the Central scenario. This effect is characterized by deferring the investment in some lines and complementing the investment in others. In this case, there is an additional investment of 200 MW for NSW-VIC, and it is also installed SA-NSW with 800 MW and Snowy in NSW. Conversely, and at the same time, the investment in QLD-NSW is 200 MW lower.

TABLE 5.10 shows the expected investment and operational cost of the base case and the no batteries case. It is possible to see that the investment of the no batteries case is 171 MMA$ cheaper than the base case. Although there is more investment in lines and an earlier deployment of PS, the lack of batteries makes the expected investment cost cheaper. Moreover, the operation of the no batteries case is 2114 MMA$ more expensive than the base case. Therefore, the savings from the investments are not enough to justify a planning without considering batteries. The operation of the no batteries case is more expensive for two reasons: Firstly, batteries cannot help to decrease the ENS in the MD in 2020 and 2025. Secondly, the storage is not enough to provide energy arbitrage when the penetration of VREG technologies increases. Hence, by not considering batteries, the expected total cost of the system is more expensive because it needs to operate more conventional generators in the peak hours. Moreover, the curtailment increases due to the lack of storage.

Location	Scenario	2020 [MW]	2025 [MW]	2030 [MW]	2035 [MW]
TAS - VIC	Central	0	0	0	750
	Fast	0	0	0	750
	Step	0	0	750	0
NSW - VIC	Slow	0	200	200	200
	Central	0	200	200	800
	Fast	0	200	200	1200
	High DER	0	200	0	0
	Step	0	200	200	800
QLD - NSW	Slow	0	200	400	200
	Central	0	200	-200	600
	Fast	0	200	200	0
	High DER	0	200	400	-200
	Step	0	200	200	1600
SA - VIC	Slow	0	0	200	200
	High DER	0	0	200	200
	Step	0	0	0	200
SA - NSW	Central	0	0	800	800
	Fast	0	0	0	800

Table 5.8 Line results – No batteries. The results are shown as the difference between the base case and the No batteries case.

Location	Scenario	2020	2025	2030	2035
NSW	Slow	0	0	0	1
	Central	0	0	1	0
TAS	Step	0	0	1	0

Table 5.9 Pumped storage – No batteries. The results are shown as the difference between the base case and No batteries case.

	Base case - POE 10	No batteries case
Expected investment cost [MMA$]	1061	889
Expected operational cost [MMA$]	7132	9246

Table 5.10 Expected investment and operational cost of the base case and no batteries case.

5.4. Case 3: POE 50

The POE 50 represents a lower MD than the base case for the NEM and the different regions. Tables 5.11, 5.12 and 5.13 show the investment for lines, batteries and PS in the scenario POE 50 with respect to the investment in base case.

In 2020, the MDs in the base case are 910 MW and 550 MW higher in NSW and NEM, respectively. Similarly, in 2025, the MDs of the base case are on average 1160 MW and 450 MW higher for NSW and the NEM, respectively. By considering the lower MD, the investment is modified in several respects. In the first epoch, the battery investment in NSW is not necessary. Moreover, in the second epoch, the line investment decreases by 400 MW for NSW-VIC and QLD- NSW, and the investment in batteries also decreases up to 1000 MW in the Step scenario. Regarding the investment in PS, it can be seen that the installed PS changes just for the High DER scenario where the model decides to invest in BON instead of Snowy. This change is due to the deployment of different lines and batteries in other states. FIGURE 5.3 illustrates the MD and the ENS in NSW of the POE 10 and POE 50 cases in 2020. In the figure, the MD of the base case (POE 10 case) has a higher ENS than the POE 50 case. The ENS in the POE 10 case justifies an earlier and higher investment in batteries in NSW and a higher deployment of lines.

FIGURE 5.4 shows the expected investment cost. The figure shows that the expected investment cost of POE 50 case is 167 MMA$ cheaper than the base case. FIGURE 5.5 displays the expected operational cost for the base case, the POE 50 case and two additional cases: the operation of the POE 10 demand with the POE 50 investment (POE 10 Inv POE 50) and the operation of POE 50 demand with the investment of the POE 10 case (POE 50 Inv POE 10). From the figure, the operation of the POE 50 case is 62 MMA$ cheaper than the base case due to the less challenging MD. When the POE 50 demand operates with POE 10 investment the operational cost of the POE 50 demand is 153 MMA$ cheaper. This operation is cheaper due to the additional investment in lines to share resources among the different nodes and in storage to provide energy arbitrage. In contrast, when the POE 10 demand is simulated with POE 50 investment it is possible to see how its operational cost increases 421 MMA$. This operation is more expensive due to lower investment, which cannot face the MD, producing more ENS.

Therefore, by planning for a lower MD, the planner can save 167 MMA$ by investing in fewer lines and batteries. These saves in the investment might imply additional operational costs, which might double the saving in additional investment if the MD is higher than the expected.

Location	Scenario	2020 [MW]	2025 [MW]	2030 [MW]	2035 [MW]
TAS – VIC	High DER	0	0	0	750
NSW - VIC	Slow	0	-400	-400	-400
	Central	0	-400	-200	-200
	Fast	0	-400	-200	-200
	High DER	0	-400	-600	200
	Step	0	-400	0	0
QLD - NSW	Slow	0	-400	0	0
	Central	0	-400	-200	-200
	Fast	0	-400	-400	-200
	High DER	0	-400	-400	-200
	Step	0	-400	-400	0
SA – VIC	Step	0	0	0	200

Table 5.11 Line results – POE 50. The results are shown as the difference between the base case and POE 50 case.

Location	Scenario	2020 [MW]	2025 [MW]	2030 [MW]	2035 [MW]
TAS	Central	0	0	200	200
	Step	0	0	0	200
SA	Central	0	0	-200	600
	Fast	0	0	1000	-200
	High DER	0	0	0	-200
	Step	0	0	0	-200
VIC	Slow	0	0	0	200
	Central	0	0	200	200
	Fast	0	0	0	200
	High DER	0	0	200	200
	Step	0	0	0	-200
NSW	Slow	-200	0	-200	-200
	Central	-200	-400	-800	600
	Fast	-200	-400	-1400	-400
	High DER	-200	-200	-600	0
	Step	-200	-1000	-1000	400
QLD	Slow	0	0	0	200
	Central	0	0	0	-400
	Fast	0	0	1000	-1400
	High DER	0	0	200	600
	Step	0	0	1000	0

Table 5.12 Battery results – POE 50. The results are shown as the difference between the base case and POE 50 case.

Location	Scenario	2020	2025	2030	2035
NSW	High DER	0	0	0	-1
TAS	High DER	0	0	0	1

Table 5.13 Pumped storage results – POE 50. The results are shown as the difference between the base case and POE 50 case.

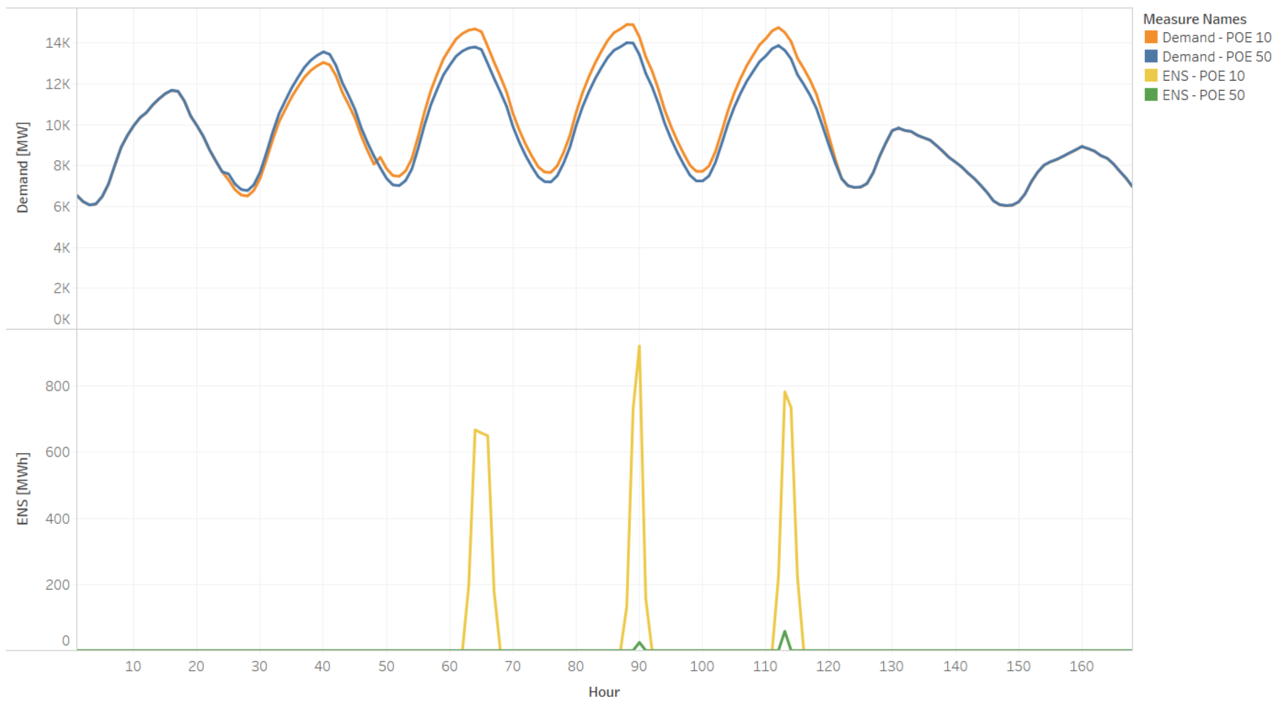


Figure 5.3 Demand and ENS in NSW for POE 10 and POE 50 in the year 2020.

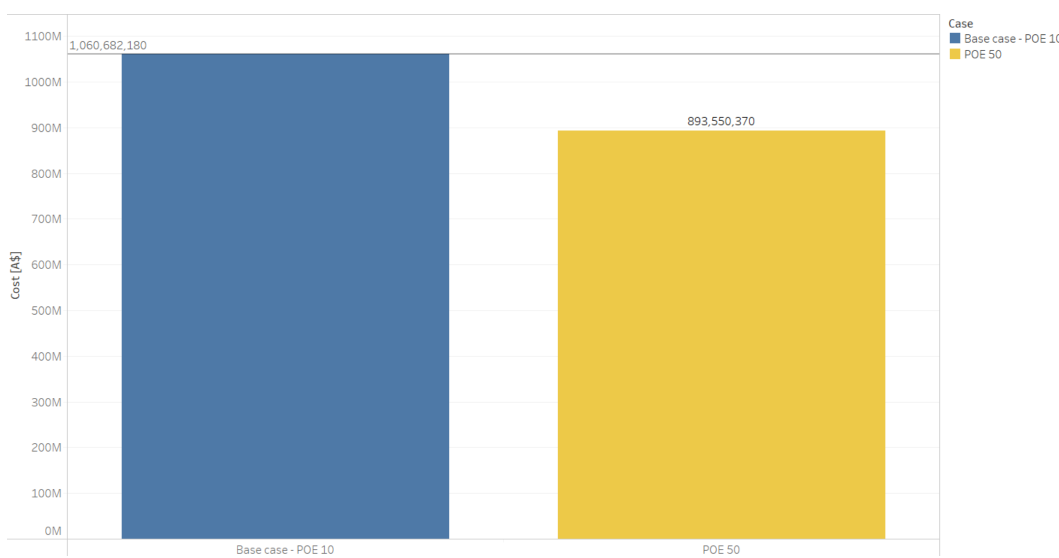


Figure 5.4 Expected investment cost by year of POE 10 and POE 50.

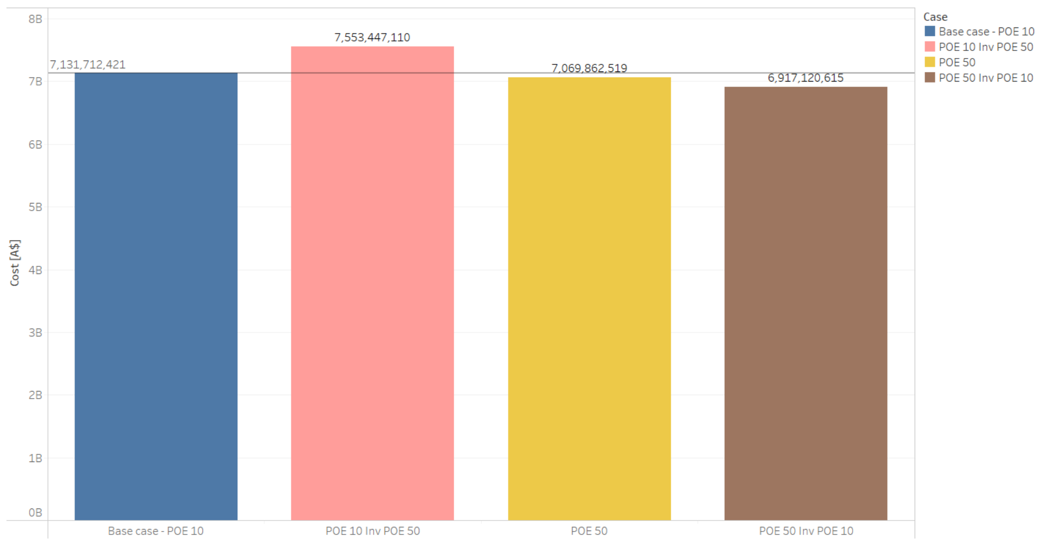


Figure 5.5 Expected operational cost by year of POE 10 and POE 50.

Chapter 6

Conclusions and Further Work

6.1. Conclusions

This thesis has implemented a co-optimization of storage and lines with an hourly time-scale resolution of the operation, which includes a transportation model for lines; a storage model with binaries charge/discharge variables for batteries; and detailed constraints of generators such as ramp-up/down, minimum up/down time, maximum/minimum operating point, and upward reserves. The model addresses five future scenarios with a stochastic approach represented by a two-stage scenario tree formulation. This formulation allows the planner to make decisions today, and as uncertainty unfolds in the upcoming years, to choose the optimal amount of storage to complement the line investment. The following paragraphs will discuss three key lessons that can be drawn from the results. The first one from the results of the stochastic formulation, the second about the inclusion of different MDs, and finally, the relation between the different investments in the optimal portfolio.

The inclusion of a high time resolution along with the inclusion of different scenarios helps to estimate the system's cost with a high accuracy. The stochastic formulation implemented allows the model to capture the short-term constraints and long-term uncertainty. The optimal solution of the stochastic formulation reduces the expected total cost by slightly increasing the total cost of the optimal deterministic solutions. By considering a stochastic approach, the planner may reduce the expected total costs between 3.5% and 36%. This shows that, in a real system, the long-term uncertainty can be capture with a stochastic approach to lead the system to a cheaper solution.

The different MDs and renewable profiles allow the model to capture the value of storage in the system. The results with different POE suggest that to deal with a very high MD, it is better to invest in local batteries in the short term. Likewise, the optimal portfolio considers more lines and batteries in the medium term. These investments can be seen in the comparison of the base case with the POE 50 case. The first epoch of the base case requires more batteries than the POE 50 case. Similarly, in the second epoch, the battery investment in the base case is greater than or equal to the investment in the POE 50 case, requiring an extra investment of 1000 MW in the Step scenario. Besides, by increasing the MD, the amounts of installed lines in the second epoch are 400 MW higher for some lines. Therefore, an optimal portfolio to face a higher MD conditions must include more batteries and lines for every scenario in the short and medium term. The inclusion of these investments is a key issue because the additional cost of operating the system without enough batteries and lines might double the cost of making these investments.

The case studies shed new light on the importance of including different types of storage in the problem formulation, which are particularly important when the technologies have a different deployment time. This model considers that batteries could be implemented in the same epoch, as soon as the planner decides to invest in them, while PSs are deployed on the next epoch. In that sense, fast availability of batteries resulted in the preferred line deferral solution, whilst PS complemented line investments in the long term. In this vein, there are three ways in which the optimal storage investment impacts the line portfolio. The first one is by complementing the line investment, which can be seen in the investment of BON and the line VIC-TAS in scenarios with high penetration of VREG. These investments are made to evacuate the excess of renewable energy resources in TAS, charging the PS in times with high VREG and sending it out when the availability of renewable resources decreases. The second effect is deferring the line investment. Batteries are the preferred technology in the optimal solution to defer investment in lines. In fact, when comparing the second epoch for the base case and the no batteries case, the line investments in the base case are 200 MW lower for the NSW-VIC and QLD-NSW lines. Moreover, the stochastic solution of scenarios with more challenging demands shows that the optimal number of lines is lower than in the deterministic portfolio and is replaced for additional batteries. The last effect is a mix of both: This can be seen in the Central scenario in the year 2030 when comparing the base case with the no batteries case. In this example, by investing in batteries decreases the investment in the SA-NSW and NSW-VIC lines, and at the same time, the investment in QLD-NSW line increase.

6.2. Further work

In this thesis, representative weeks were chosen with the k-means method to represent the system's demand. The weekly representation can capture the value of some storage plants such as small PS and batteries. On the other hand, large PS can provide interweek or interseason energy arbitrage. In this vein, increasing the length of representative periods can help to capture the value of bigger storage plants and their impact in the planning solutions. Therefore, further studies are suggested with a focus on the number and length of representative periods to capture the different phenomena while keeping a reasonable computational burden.

It has been shown that the deployment of storage technologies is necessary under the context of future decarbonisation. Despite the effort made in this thesis to address different types of energy storage, some technologies are still developing. For instance, in the upcoming years, hydrogen production is expected to increase, which may facilitate the production of hydrogen in a large scale to store energy. For this reason, the inclusion of this technology in the model could provide interesting insights.

Finally, the role of other key services can be included in the problem formulation. Demand response can be easily added to the operational model and could even be considered as an investment option. Another example is the integration of different kinds of reserves or complex reserve requirements depending on the generation of VREG.

Moreover, the development of new technologies and services in a distribution level could highly impact the investment in large scale systems. Hence, the integration of different key services should be explored more thoroughly in the planning problem.

Chapter 7

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