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Security-Constrained Planning and Adequacy Assessment of the Australian NEM Transition: An Interoperable High-Fidelity Open-Source Framework

Ghulam Mohy-ud-din, Biswajit Bala, Yunqi Wang and Helen Wu

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Acknowledgement of Country

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List of Acronyms and Abbreviations

AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AESO	Alberta Electric System Operator (Canada)
AI	Artificial Intelligence
Antares	Open-source power system adequacy and market simulation tool (RTE)
AR-PST	Australian Research in Power System Transition
Aurora	Commercial electricity market modelling and forecasting software
BESS	Battery Energy Storage System
CDP	Candidate Development Path
CER	Consumer Energy Resources
CNSW	Central New South Wales (NEM sub-region)
CQ	Central Queensland (NEM sub-region)
CSA	Central South Australia (NEM sub-region)
CSIRO	Commonwealth Scientific and Industrial Research Organization
DC	Direct Current
DC-OPF	Direct Current Optimal Power Flow
DER	Distributed Energy Resources
DLR	Dynamic Line Rating
ED	Economic Dispatch
EENS	Expected Energy Not Served
ELCC	Effective Load-Carrying Capability
EMT	Electromagnetic Transient
EMTP	Electromagnetic Transients Program
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ESOO	Electricity Statement of Opportunities (AEMO)
EUE	Expected Unserved Energy
EUH	Expected Unserved Hours
FCC	Firm Capacity Contribution
FES	Future Energy Scenarios (National Energy System Operator, Great Britain)
GG	Gladstone Grid (NEM sub-region)
GIS	Geographic Information System
G-PST	Global Power System Transformation (Consortium)
GridView	Commercial production-cost simulation software
GW	Gigawatt
GWh	Gigawatt-hour

HELICS	Hierarchical Engine for Large-scale Infrastructure Co-Simulation
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IBR	Inverter-Based Resources
IEEE	Institute of Electrical and Electronics Engineers
ISGT	IEEE Innovative Smart Grid Technologies (conference)
ISO	Independent System Operator
ISO-NE	ISO New England (USA)
ISP	Integrated System Plan (AEMO)
LOLD	Loss of Load Duration
LOLE	Loss of Load Expectation
LOLEV	Loss of Load Events
LOLF	Loss of Load Frequency
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LOLR	Loss of Load Risk
LT	Long-Term
MATPOWER	Open-source MATLAB power system simulation package
MEL	Melbourne (NEM sub-region)
MISO	Midcontinent Independent System Operator (USA)
MT	Medium-Term
MT-PASA	Medium-Term Projected Assessment of System Adequacy
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NESO	National Energy System Operator (Great Britain)
NEUE	Normalized Expected Unserved Energy
NNSW	Northern New South Wales (NEM sub-region)
NQ	North Queensland (NEM sub-region)
NREL	National Renewable Energy Laboratory (USA)
NSA	Northern South Australia (NEM sub-region)
NSW	New South Wales
NYISO	New York Independent System Operator (USA)
OCCTO	Organization for Cross-regional Coordination of Transmission Operators (Japan)
ODP	Optimal Development Path (AEMO Integrated System Plan)
OPF	Optimal Power Flow
PASA	Projected Assessment of System Adequacy
PES	IEEE Power & Energy Society
PJM	PJM Interconnection (USA)

PLEXOS	Commercial energy market modelling and simulation software
PRAS	Probabilistic Resource Adequacy Suite (NRL)
PRM	Planning Reserve Margin
PROMOD	Commercial production-cost and market simulation software
PSCAD	Power Systems Computer Aided Design (electromagnetic transient software)
PSS/E	Power System Simulator for Engineering
PV	Photovoltaic
QLD	Queensland
QNI	Queensland–New South Wales Interconnector
REZ	Renewable Energy Zone
RM	Reserve Margin
RTDS	Real-Time Digital Simulator
RTE	Réseau de Transport d'Électricité (French transmission system operator)
RTEP	Regional Transmission Expansion Plan
SA	South Australia
SCTNEP	Security-Constrained Transmission Network Expansion Planning
SESA	Southeast South Australia (NEM sub-region)
SEV	Southeast Victoria (NEM sub-region)
SNEM	Synthetic National Electricity Market (2000-bus) dataset
SNSW	Southern New South Wales (NEM sub-region)
SNW	Sydney, Newcastle and Wollongong (NEM sub-region)
SOC	State of Charge
SQ	Southern Queensland (NEM sub-region)
ST	Short-Term
ST-PASA	Short-Term Projected Assessment of System Adequacy
TARA	Transmission Adequacy and Reliability Assessment (POWERGEM planning software)
TAS	Tasmania (NEM region)
TNSP	Transmission Network Service Provider
TPL	Transmission Planning (NERC reliability standards)
TYNDP	Ten-Year Network Development Plan (ENTSO-E)
UC	Unit Commitment
USA	United States of America
USE	Unserved Energy (NEM-aligned; percentage of regional annual demand)
VIC	Victoria
VNI	Victoria–New South Wales Interconnector
VRE	Variable Renewable Energy
WNV	Western and North-Western Victoria (NEM sub-region)

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Data and methodological inputs

- AEMO for the 2024 Integrated System Plan (ISP), the Inputs, Assumptions and Scenarios Report (IASR) 2024 to 2025, the publicly registered generator and connection-point data, and the 2025 Electricity Statement of Opportunities (ESOO) used to anchor the demand, generation, and operational reliability inputs throughout this project.
- CSIRO for the development of open-source Synthetic NEM2000 Bus dataset (SNEM), which underpins the system representation used in this work.
- NRL for the open-source Sienna modeling framework including packages such as PRAS.jl, PowerSystems.jl, and PowerSimulations.jl, which underpin the Julia-based toolchain used for adequacy and operability analysis.
- LANL for the open-source PowerModels.jl package;
- KU Leuven for the open-source PowerModelsACDC.jl package; and
- CSIRO Energy for the open-source PowerModelsACDCsecurityconstrained.jl package, which was used to develop iPlan.jl for time-sequential SCTNEP.

Statement on the synthetic character of the SNEM dataset

The outcomes in this work should be interpreted with appropriate caution as the transmission and generation dataset used throughout this work (the 15-region SNEM) is a synthetic representation of the NEM, derived from publicly available sources. Three aspects of the dataset are intrinsically synthetic and should be borne in mind when interpreting the results.

- The 15 sub-regions used in this project (NNSW, CNSW, SNW, SNSW, WNV, MEL, SEV, NQ, CQ, GG, SQ, NSA, CSA, SESA, TAS) were constructed through clustering of the SNEM2000 bus coordinates and manual reconciliation against the published ISP sub-region boundaries. The clustering is internally consistent but is not an authoritative AEMO sub-regional definition.
- The mapping of the AEMO ISP scenario load demand, wind, solar, and hydro traces onto the 15 SNEM sub-regions is a synthetic scaling-and-disaggregation procedure. Where ISP traces are published only at the parent-region level, the same scaled series is reused across child sub-regions of the same region (for example, VIC traces scaled to WNV, MEL, and SEV; CSA traces scaled to NSA).
- The geographical placement of renewable energy zone generation, storage, and transmission infrastructure, in-progress and committed project’s transmission infrastructure, and candidate transmission option’s infrastructure such as lines, transformers, buses, generators, and storage resources within each sub-region and their associated parameters is synthetic. The SNEM dataset does not carry authoritative

geographic coordinates for these assets, and the placement adopted here is consistent with the underlying SNEM topology but is not a one-to-one mapping to the physical NEM infrastructure.

These assumptions are necessary to enable analysis in the absence of an authoritative open GIS-informed reference dataset; however, they limit interpretation of results at sub-regional or asset level. For further details see Chapter 4.

Use of AI-assisted text refinement

AI tools were used under human supervision to assist with drafting, language refinement, formatting, and consistency editing. The use of AI for editorial support is consistent with CSIRO's research-integrity guidelines on responsible use of generative AI in research output preparation.

Executive summary

The Australian National Electricity Market (NEM) is undergoing a structural transformation of unprecedented scale and pace. Accelerated retirement of dispatchable coal generation, rapidly expanding variable renewable capacity, the commissioning of large energy-limited storage portfolios, and the anticipated rise of long-distance and high-voltage transmission corridors fundamentally reshape both the planning and the operational adequacy challenges that the NEM must address. These developments do not undermine established planning practice; instead, they raise the bar on what planning studies must now deliver in terms of temporal resolution, security representation, and adequacy assessment. In response, this stage of the AR-PST programme develops and demonstrates an open-source planning framework that complements existing industry methods while extending their capability to address these emerging requirements.

The research undertaken in AR-PST Stage 5 develops an interoperable open-source planning framework that integrates time-sequential security constrained transmission network expansion planning (SCTNEP) with probabilistic and time-sequential production cost simulation-based projected system adequacy assessment. The framework enables forward-looking, chronologically resolved evaluation of transmission investment, operational security, and adequacy risk across the 2025 to 2051 horizon and demonstrates the outcomes using the Synthetic-NEM2000[1] dataset on the Step Change, Progressive Change, and Green Energy Exports scenarios of AEMO's 2024 Integrated System Plan. The work is presented in two complementary parts: Part I addresses security-constrained system planning, and Part II addresses the projected assessment of system adequacy.

This framework is developed with a clear ambition to advance beyond the current state of the art. The mathematical models included in this framework are as follows:

- Time-sequential SCTNEP model that incorporates AC and HVDC transmission, detailed system operation, and inter-temporal constraints for both generation and storage resources. The formulation explicitly models N-1, N-1-1, and N-k contingencies with post-contingency corrective actions from both generation and storage units, dynamic line ratings, aggregated consumer energy resource (CER) integration, reliability and adequacy risk constraints enabling robust adequacy and reliability-aware decision making. These models are part of iPlan.jl[2].
- Probabilistic models for representing long-term renewable and demand uncertainty, including solar and wind resource variability and long horizon demand evolution. These models capture spatial and temporal correlations to enable realistic representative scenario generation (seasonal and non-seasonal best, typical and worst representations for each scenario) for planning studies.

[1] Synthetic 2000 bus data for National Electricity Market (NEM) of Australia. Available: https://github.com/csiro-energy-systems/Synthetic-NEM-2000bus-Data

[2] iPlan.jl is a Julia package for integrated transmission-distribution network expansion planning. Available: Mohy Ud Din, Ghulam (2026): iPlan.jl. CSIRO. v1. Software. https://doi.org/10.25919/h7py-3f46

- Probabilistic models (Monte Carlo simulation sampling) for long-term (1-, 6-, and 20-year time-period, half-hourly resolution) system adequacy assessment using probabilistic resource adequacy suite (PRAS.jl[3]) allowing for the incorporation of energy-limited storage resources, forced outages, and time-series of renewable resources and load demands to enable multi-region composite adequacy assessments in line with the standard metrices[4].
- Time-sequential production cost simulation models for short-term (1-week) system adequacy assessment using PowerSimulations.jl[5].
- Seamless translation of model outcomes between iPlan.jl, PRAS.jl, and PowerSimulations.jl with consistent data schemas and time-series alignment. This is a distinguishing feature of this work enabling deliberate interoperability between the planning and adequacy layers: investment pathways produced by the SCTNEP model are carried forward year-by-year into the adequacy assessment, addressing a recognized gap in which planning and adequacy are otherwise evaluated in isolation. All adequacy assessment models are part of iPASA.jl[6].

This open and reproducible orientation is itself a contribution: it lowers the structural integration burden that individual research efforts currently absorb, and it allows the methods, datasets and benchmarks developed here to be inspected, reproduced and extended by the wider research and planning community. The principal findings and insights from the current AR-PST stage are best read as indicative demonstrations of the framework's capability on a synthetic dataset rather than as definitive investment prescriptions noting that only a subset of the broader planning requirements could be assessed within the available timeframe.

- Investment quantum and uncertainty are significant, with total transmission investment to 2051 ranging A$25.4 to A$66.2 billion across the 18 scenario representation combinations analyzed. Of this, approximately A$23.6 billion of this is invariant across all combinations and constitutes a no-regret investment core dominated by VNI West, the South Australian Mid-North REZ expansion, the Bannaby to Sydney West connectors, and the Queensland CQ to SQ to NNSW backbone.
- Security overlay convergence is observed when enforcing N−1 feasibility against the screened critical contingencies, bringing the three best-case pathways to a similar terminal investment level of approximately A$64.1 billion, broadly consistent with the worst-case seasonal envelope. Under the assumptions considered, this indicates that the application of security requirements narrows the variation in terminal transmission investment costs across the studied pathways, while differences remain in the timing and sequencing of network developments.

[3] PRAS.jl is a collection of tools for bulk power system resource adequacy analysis and capacity credit calculation. Available: [online] https://github.com/NREL/PRAS

[4] Standard metrics include Loss of Load Expectation (LOLE), Loss of Load Probability (LOLP), Expected Unserved Energy (EUE), Loss of Load Events (LOLEV), Expected Energy Not Served (EENS), Expected Unserved Hours (EUH), Capacity Credits, Planning Reserve Margin (PRM), Effective Load Carrying Capability (ELCC), Firm Capacity Contribution (FCC), Loss of Load Risk (LOLR), Shortfall Severity Index, Reserve Shortfall Hours, Storage State-of-Charge Adequacy, Interconnector Support Adequacy, and Simultaneous Shortfall Probability for regional, inter-regional, and multi-regional assessments.

[5] PowerSimulations.jl is a Julia package for power system modeling and simulation of power systems operations. It supports annual, monthly or weekly time-sequential production cost modelling simulation by formulating sequential unit commitment and economic dispatch optimization. Available: [online] https://github.com/NREL-Sienna/PowerSimulations.jl

[6] iPASA.jl is a Julia package for projected assessment of system adequacy. Available: https://github.com/csiro-internal/ensys-iPASA.jl

- Seasonal versus non-seasonal pathways analysis shows that seasonal modelling exposes adequacy mechanisms that non-seasonal analysis does not capture, particularly the multi-day correlated low-renewable risk to which energy-limited storage is exposed. Seasonal pathways are more front-loaded and consistently higher in total investment than their non-seasonal counterparts; this premium is partially recovered through lower curtailment and lower residual gas dispatch in operations.
- Adequacy under the planning pathway improves materially, with the SCTNEP pathway reducing NEUE by 0.20 to 0.28 in the most-stressed areas (CSA and SNW) and reducing LOLH by 70 to 90 % in NSA, CSA, SNW, and GG, with no adequacy degradation observed elsewhere. The contingency-constrained pathway delivers a further 28 to 56 % reduction in LOLH and brings GG, NQ, and SQ into compliance with the NEM Reliability Standard. Across all representations, five areas (CNSW, SESA, CQ, MEL, NNSW, SNSW, TAS, SEV, WNV) require no further planning action.
- Residual adequacy stress and iteration remain evident, with NSA, CSA, and SNW still exhibiting LOLH of approximately 9 to 19 hours per year after the contingency-constrained best representation. Diagnostic corridor evidence attributes this residual stress to the unrelieved CSA to WNV corridor, partial relief along CNSW to SNW and CSA to SESA pathways, under-relief of GG to CQ transfer in the best representation, and the structural absence of import capability into NSA. The residual gap is quantifiable and addressable, and it motivates the iterative refinement programme set out in Chapter 11.

The combined evidence supports four practical implications for transmission planning and policy in the NEM.

- Approval and procurement of the no-regret investment core (approximately A$23.6 billion) can proceed independently of scenario adjudication because the economic justification is invariant across plausible futures.
- The convergence of the security-constrained terminal investment to approximately A$64.1 billion provides a robust upper anchor for regulated transmission expenditure to 2051. Below this envelope, planning decisions should be staged and adaptive, resolving scenario uncertainty as the transition unfolds.
- Seasonal and contingency-aware analyses jointly identify residual adequacy risk in NSA, CSA, SNW, and GG that is not visible to non-seasonal or N-0 representations. These risks must be internalized within the planning framework, through corridor augmentation, in-area resources, and area-level reliability constraints.
- The framework and tool stack developed in this project can be adapted to AEMO ISP refresh cycles and to Transmission Network Service Provider augmentation decisions. The open-source orientation of the implementation supports transparency, reproducibility, and community contribution.

The work delivered in this stage contributes to the AR-PST Research Roadmap and advances several of its five research programmes. The probabilistic, correlation-preserving scenario generation contributes to Programme 1: the Long-term Uncertainty, and specifically to the scenario-development-for-planning-studies stream. The time-sequential operational modelling and the explicit security formulation advance the Programme 2: Power System Operation through its steady-state-operation-modelling and security-constraints-formulation streams. The integrated treatment of credible and non-credible contingencies, together with the suite of adequacy and reliability indices, contributes to the Programme 3: Reliability (security and adequacy) and resilience. The closed-loop coupling of planning and adequacy, and the staged, no-regret investment logic, support the Programme 4: Decision-Making on methodologies for decision-making under uncertainty and on the interdependence of transmission, distribution and generation planning streams. Finally, the incorporation of aggregated CERs connects the framework to the Programme 5: Distributed Energy Systems. In these ways, the stage operationalizes, on a common open dataset and tool stack, a set of capabilities that the roadmap identifies as priorities for delivering high-value, implementable insight to Australian industry within its intended timeframe.

These outcomes should be interpreted with appropriate caution as the synthetic geographic placement of network assets in the present dataset limits the interpretation of sub-regional and asset-level results. Accordingly, the report identifies a GIS-informed reference dataset, an extended candidate-technology library (including long-duration storage, demand-side flexibility, hydrogen, and system-strength resources), climate-aware inputs, and the internalization of area-level reliability constraints as priority directions for subsequent stages. Overall, this stage provides a transparent, reproducible and operationally grounded foundation that complements existing planning practice and establishes a basis for the continued, iterative development of integrated planning and adequacy capability for the evolving NEM.

Part I Security-Constrained System Planning

This part of the report focuses on security-constrained system planning, examining how transmission network development can be guided to maintain secure operation under credible contingencies as the National Electricity Market (NEM) undergoes rapid structural change.

The analysis is conducted from a long-term planning perspective, with security requirements embedded directly into transmission expansion decisions rather than assessed as a post-processing step.

1 Introduction

1.1 Long-distance transmission in the NEM and the need for security constraints in system planning

The National Electricity Market (NEM) is characterized by long transmission distances, geographically dispersed generation resources, and strong reliance on inter-regional power transfers. The physical structure of the network means that power flows are often concentrated on a limited number of major transmission corridors, particularly during periods of high renewable output or elevated regional demand. As a result, the secure operation of the system is closely linked to the availability and performance of key network assets.

Historically, system security in the NEM was supported by a large fleet of synchronous generators that provided inertia, fault current contribution, and relatively predictable operating conditions. Under this environment, transmission planning could focus primarily on meeting forecast demand growth and facilitating new generation connections, with security issues often managed through incremental network reinforcements and operational measures.

This operating context has changed significantly in recent years. Accelerated retirement of synchronous coal-fired generation, combined with rapid development of renewable energy zones located far from major load centers, has altered both the magnitude and direction of power flows across the network. Power flow patterns have become more variable and less predictable, increasing the sensitivity of the system to the loss of individual network elements. Under certain operating conditions, credible outages of transmission lines, transformers, or interconnectors can now result in widespread thermal overloads, voltage excursions, or system-wide redispatch requirements [1], [2].

In the Australian planning framework, system security is defined through the application of the N-1 criterion, which requires the power system to remain within acceptable thermal, voltage, and stability limits following the loss of any single credible element. This requirement is embedded in the National Electricity Rules and further articulated through Australian Energy Market Operator (AEMO) Power System Security Guidelines, which specify the conditions under which preventive and corrective actions may be relied upon in operational and planning studies [3], [4].

From a long-term planning perspective, increasing uncertainty in future operating conditions reduces the practicality of assuming corrective operational actions to manage post-contingency violations. Future dispatch patterns, reserve availability, and operational practices cannot be specified with confidence over multi-decade horizons, particularly in a system with high penetration of variable renewable energy. For this reason, preventive security where the network is designed to withstand credible contingencies without assuming corrective intervention provides a more robust and transparent basis for transmission planning decisions.

Consequently, security considerations have moved from a secondary verification step to a central planning requirement in the NEM. Transmission development must now explicitly account for how evolving generation portfolios, demand patterns, and inter-regional transfers interact with critical contingencies to define the secure operating envelope of the future power system [5], [6].

1.2 Massive expansion of energy limited and time-coupled storage capacity in the NEM and the need for time-sequential models for system planning

Australia's electricity system is entering a decisive transition phase characterized by the progressive retirement of coal-fired generation and the rapid expansion of variable renewable energy in the NEM. In this context, system reliability is increasingly dependent on storage technologies capable of delivering firm, dispatchable capacity over extended durations. Policy and planning bodies, including the Energy Security Board, have identified energy storage as critical infrastructure for maintaining energy security, affordability, and investor confidence throughout the transition.

Industry outlooks point to rapid growth in large-scale battery energy storage systems (BESS). The AEMO's integrated system plan (ISP) Step Change Scenario indicates that, as conventional generators retire, storage could provide around 65% of dispatchable capacity by 2035 and up to 75% by 2050 [7]. While these projections are scenario-dependent, they reflect a broader structural shift from fuel-based generation toward storage-enabled system flexibility. This transition is already evident in the NEM, where deployment is accelerating rapidly. Installed storage capacity is expected to double again by the end of 2026, and if committed and proposed projects proceed as planned, the operational grid-scale BESS could reach roughly seven times today's level (around 16.8 GW) by 2027, underscoring the pace at which storage is becoming central to system reliability [8].

As indicated by AEMO's ISP, the storage may need to reach around 55 GW and over 600 GWh by 2050 under the ISP Step Change Scenario, a scale that cannot be delivered by short-duration batteries alone and instead requires long-duration storage, such as pumped hydro, to provide multi-day energy shifting and manage extended renewable energy shortfalls. Projects such as Snowy 2.0 exemplify this role, offering large energy capacity, long asset life, and firming during prolonged low-renewable periods. However, as indicated by AEMO, there remains significant uncertainty around investment in pumped hydro storage projects. Beyond energy shifting, storage also delivers essential system services such as frequency control, inertia, system strength, fast ramping, and black-start, which become increasingly critical as synchronous generation retires.

A defining feature of storage technologies is that they are energy-limited and inherently time-coupled. Their operation is governed by inter-temporal constraints, with state of charge evolving from prior charging and discharging decisions, subject to efficiency losses and capacity limits. As a result, dispatch at any point depends on both past system conditions and expectations of future states: charging aligns with periods of surplus renewable generation, while discharging is reserved for anticipated scarcity. These chronological dependencies fundamentally distinguish storage from conventional generation.

This characteristic has important implications for system modelling. Many planning approaches rely on non-chronological representations, where periods are treated independently. While computationally efficient, these methods cannot capture the sequential evolution of storage state of charge or the persistence of renewable variability across the entire day and multiple days. Consequently, they tend to overestimate storage capability, underestimate renewable curtailment, and misrepresent system adequacy during extended stress events, as widely documented in the literature, particularly in high-renewable systems [9], [10].

Time-sequential modelling addresses these limitations by explicitly representing chronological system evolution and enforcing inter-temporal consistency in storage operation. However, these approaches introduce substantial computational burdens when applied to large-scale networks, long planning horizons, and multiple scenarios. Moreover, common assumptions such as perfect foresight in storage dispatch can reduce realism. These challenges motivate the development of improved methods, including chronological time-series reduction and stochastic or limited-foresight formulations.

1.3 Scope of the system planning problem in this project

This project addresses both long-term system planning and projected assessment of system adequacy. At a high level, the planning task determines how the transmission network should evolve under a set of representative future scenarios, while the adequacy assessment task tests whether those planning outcomes remain reliable and secure when examined at full temporal resolution and across a wider range of operating conditions. The project therefore not only identifies candidate network developments but also evaluates whether the resulting system can deliver acceptable performance across ultra-short-, short-, medium-, and long-term reliability horizons.

Within the planning component, the core problem is formulated as a Security-Constrained Transmission Network Expansion Planning (SCTNEP) problem. Its purpose is to identify transmission augmentations, reinforcements, and new corridors required to maintain secure and economically efficient operation of the NEM as demand patterns, renewable penetration, storage deployment, and generator retirements evolve. The model co-optimizes investment decisions and operational feasibility subject to network constraints and N-1 security criteria, so that the resulting development plan is both cost-effective and technically feasible under normal and contingency conditions.

The planning model is time-sequential in structure but implemented using best, typical, and worse seasonal (four-day) and non-seasonal (per-day) representative time periods rather than full chronological traces. This allows inter-temporal operating effects, including those associated with energy storage behavior, to be reflected within the planning formulation while preserving computational tractability. Representative periods are derived from 2024 ISP trace data to capture the main seasonal, diurnal, and stressed operating patterns relevant to transmission planning. In this project, the planning model is therefore intended to provide a tractable but technically meaningful approximation of long-term system evolution, rather than a full chronological simulation of all operating intervals.

A defining scope boundary is that the planning model does not endogenously optimize generation, storage, or Renewable Energy Zone (REZ) candidate development. Instead, these elements are treated as exogenous inputs, consistent with the scenario definitions in the 2024 AEMO ISP. That is, storage deployment, renewable build-out, REZ development, committed and anticipated projects, and generator retirement pathways are adopted from the ISP scenarios and the Candidate Development Paths (CDPs) and then imposed within the model. The planning task is therefore focused on identifying the transmission network augmentations required to support those assumed system developments in each scenario and subsequent CDPs, rather than re-solving the broader generation expansion problem. The principal model inputs are summarized in the table below.

Table 1.1 Planning model inputs and assumptions

INPUT CATEGORY	DESCRIPTION	ROLE IN THE PLANNING MODEL
Existing power system data	Existing lines, transformers, substations, topology, thermal limits, voltage levels, and other electrical parameters of the NEM transmission system This project uses Synthetic NEM2000 bus dataset[7] Further detail presented in Section 4.1	Forms the base network and operation representation against which future augmentations are assessed in the planning optimization Unit commitment not fully represented in the long-term planning optimization but in the adequacy assessment models
In-progress and committed network projects	Transmission developments already committed, approved, or under construction at the time of analysis	Included as assumed future network elements as per given completion years rather than optimization decisions
AC and HVDC candidate transmission expansions	Potential new lines, corridor augmentations, network reinforcements, and interconnector developments considered in the study	Represent the decision variables optimized by the SCTNEP model
Scenario-based ISP traces (demand and renewable generation time-series data)	Scenario traces from the 2024 ISP used to characterize system conditions over time	Provide the source data from which representative planning periods are derived Full chronological traces are used in adequacy assessment models
Scenario-based representative periods	Selected representative operating periods constructed from full ISP traces Further detail presented in Section 4.2	Capture key seasonal, diurnal, and stressed operating conditions while maintaining computational tractability
Scenario and CDP based REZs generator fleet	Existing and future generators, including technology type, location, capacity, availability assumptions, and operating characteristics	Determine supply capability and influence network utilization, congestion, and power flows
Generator retirements	Scheduled yearly retirements for thermal and other existing plant	Shape future system topology, transfer needs, and reliance on new transmission corridors
Scenario and CDP based storage fleet	Storage resources, capacities, durations, and operational characteristics	Treated as exogenous inputs that affect dispatch patterns and inter-temporal network use
Scenario and CDP based REZ transmission connections and extensions	REZ-related transmission developments assumed within the relevant CDPs	Included where already specified in CDPs, while additional broader network augmentations remain candidate decisions

[7] CSIRO. Development of a Benchmark Synthetic Network Model for the Australian National Electricity Market. https://arxiv.org/: CSIRO; 2023. csiro:EP2023-2007. Available: https://github.com/csiro-energy-systems/Synthetic-NEM-2000bus-Data

List of critical contingencies	Outage events covering AC as well as HVDC lines, converters, transformers, generators, and other relevant equipment	Used to enforce N-1 secure operation in normal and contingency states in planning model formulation
Investment cost data	Capital cost assumptions for candidate AC and DC network developments	Support economic comparison and optimization of expansion pathways

These inputs establish a planning problem that is broad in system representation but disciplined in boundary definition. The model captures the interaction between transmission capability, dispatch feasibility, congestion, losses, security constraints, and storage operation, while avoiding endogenous optimization of generation, storage, and REZ candidate expansion. This is consistent with the role of transmission planning in the ISP context, where many non-network developments are already specified within scenario narratives and development pathways.

The outputs of the planning model are the network development outcomes justified under each scenario and subsequent CDPs. These include the selected AC and HVDC augmentations, the timing and configuration of new or upgraded circuits, indicative investment cost, changes in network power-flow patterns, congestion relief, and system-level effects such as losses and transfer capability. The model therefore provides the transmission planning layer required to translate ISP scenario assumptions into technically feasible network pathways that can be compared consistently across futures.

The planning models developed in this project are implemented in open-source Julia tools, principally iPlan.jl[8], built on top of the PowerModels ecosystem. This is important for transparency, reproducibility, and extensibility. Because the model is developed within an open and modular framework, it can be updated with revised network data, alternative scenario assumptions, or additional candidate projects without changing the underlying methodological basis. It also supports greater auditability of assumptions and facilitates reuse in future ISP-aligned planning studies, REZ assessments, and interconnector evaluations.

A key complementary element of the project is that the full chronological traces are captured within the framework for projected assessment of system adequacy. While the planning model uses representative periods for computationally tractable expansion optimization, the adequacy models examine the resulting planning outcomes at much finer temporal resolution. This framework covers ultra-short-, short-, medium-, and long-term adequacy assessments, as well as stressed-condition analysis using fast probabilistic assessment methods based on standard metrices. In addition, for ultra-short-term analysis, a complete time-sequential unit commitment model is used to examine operational metrics and unserved energy events with full chronological detail.

These adequacy assessment models are drawn from the Sienna suite of tools, including PRAS.jl[9] for probabilistic adequacy analysis and PowerSimulation.jl[10] for detailed chronological simulation, all within the Julia ecosystem. A major advantage of this common environment is interoperability. All

[8] iPlan.jl is a Julia package for integrated transmission-distribution network expansion planning. Available: Mohy Ud Din, Ghulam (2026): iPlan.jl. CSIRO. v1. Software. https://doi.org/10.25919/h7py-3f46

[9] https://github.com/NatLabRockies/PRAS

[10] https://github.com/Sienna-Platform/PowerSimulations.jl

adequacy assessment models are implemented in open-source Julia package iPASA.jl[11]. Planning outputs from iPlan.jl can be transferred more consistently into adequacy and operational assessment workflows using iPASA.jl, reducing model translation effort and limiting mismatches in assumptions, data structures, and network representations across tools. This supports a robust end-to-end workflow in which long-term transmission planning outcomes can be systematically stress-tested using detailed reliability and operational models.

Taken together, the scope of the system planning problem in this project can be summarized as follows: the project develops a representative-period, time-sequential, security-constrained transmission expansion planning model for the NEM using ISP 2024 scenario inputs for demand, generation, storage, REZ development, committed projects, and generator retirements; it evaluates candidate AC and HVDC transmission augmentations against technical and economic criteria; and it complements this planning task with a suite of higher-resolution adequacy assessment models that test the reliability implications of the resulting network plans across multiple operational timescales. In this way, the project treats planning and adequacy assessment as linked components of a single analytical workflow.

[11] iPASA.jl is a Julia package for projected assessment of system adequacy. Available: https://github.com/csiro-internal/ensys-iPASA.jl

2 Current Practice, Methodologies, Tools and Implementations in System Planning

2.1 Current industry practice in power system planning

Power system planning has evolved from a relatively narrow exercise in least-cost infrastructure provision to a multi-objective process that must simultaneously address reliability, security, economics, decarbonization, operability, and resilience. In contemporary power systems, especially those experiencing rapid retirement of conventional generation and large-scale entry of inverter-based resources, transmission planning is no longer concerned only with meeting forecast demand under intact conditions. It must also ensure that the future system can remain secure under credible contingencies, accommodate variable renewable energy, integrate storage, and support policy-driven transition pathways. As a result, current industry practice increasingly treats planning as a coordinated, scenario-based, and security-aware process rather than a static network design exercise.

2.1.1 Planning objectives and drivers

The main drivers of contemporary system planning can be grouped into four broad categories.

- Reliability: ensuring sufficient infrastructure and resource capability to serve demand across a range of conditions, including peak demand, low renewable output, and stressed system states.
- Security: maintaining acceptable system performance following credible contingencies, typically under deterministic N-1 criteria, while increasingly considering dynamic and stability-related constraints.
- Economics: identifying development pathways that minimize long-run system cost, reduce congestion, limit curtailment, and improve utilization of generation and transmission assets.
- Decarbonization and transition policy: enabling renewable integration, supporting REZs, accommodating storage, and managing thermal generator retirements in line with emissions and policy objectives.

These drivers are strongly interdependent. A transmission plan that is economically attractive under average conditions may prove insecure under contingency conditions; a least-cost renewable build-out may not be deliverable without timely network augmentation; and a system that is reliable in aggregate may still face local security or stability limitations. Current practice therefore increasingly seeks planning methods that expose these trade-offs explicitly rather than addressing them sequentially.

2.1.2 Planning frameworks and process

Across many jurisdictions, planning has moved toward structured, staged frameworks that combine long-term scenario analysis with shorter-term reliability and operational assessments. In the Australian context, this is reflected in the ISP and related assessment processes, where long-term development pathways are informed by scenario narratives, candidate development paths, engineering screening, and system security considerations. Similar multi-stage approaches are used internationally, even where the formal planning instruments differ. A typical contemporary planning workflow includes the following elements:

- Scenario development and policy framing: defining future pathways for demand growth, electrification, fuel prices, generator retirement, renewable uptake, storage deployment, and emissions policy.
- Resource and capacity outlook assessment: examining generation adequacy, resource mix evolution, and broad supply-demand balance.
- Chronological and operational assessment: using time-sequential or production-cost style models to examine dispatch patterns, storage cycling, congestion, and system stress conditions.
- Transmission option development: identifying candidate augmentations, interconnectors, reinforcements, REZ access works, and non-network alternatives.
- Security and reliability screening: testing candidate plans against contingency conditions, thermal limits, transfer constraints, and where relevant stability and dynamic operability considerations.
- Economic comparison and pathway selection: comparing development options on cost, benefits, risk, and policy alignment.
- Detailed engineering validation: confirming feasibility using higher-fidelity operational and technical studies.

This layered process reflects an important feature of current practice: no single model or study stage is expected to answer the whole planning problem. Instead, system operators combine multiple analytical layers, each with different temporal resolution and physical detail.

2.1.3 Security-constrained planning as standard practice

One of the clearest shifts in modern planning practice is the movement from post-planning security checking to security-constrained planning. In earlier planning approaches, network augmentations were often chosen on economic or load-growth grounds first, with contingency analysis performed afterwards as a verification step. This became increasingly inadequate as systems grew more highly interconnected, more transfer-dependent, and more exposed to variable renewable generation patterns.

Today, most major system operators incorporate security criteria explicitly within sequential planning workflows, but do not embed them directly into the core optimisation formulations. The dominant requirement remains preventive N-1 security, meaning that the system should remain within acceptable limits following the loss of any one credible element, such as an AC or HVDC transmission line, transformer, or generator. However, current practice is also broadening beyond simple thermal contingency checks to include issues such as voltage stability, system strength, fault levels, oscillatory behavior, and restoration capability, particularly in systems with high penetrations of inverter-based resources.

Across major power systems, N-1 security remains the dominant deterministic standard for transmission planning and expansion assessment. This is evident in planning frameworks used by AEMO in Australia [11], NERC-governed planners in North America [12], ENTSO-E in Europe [13], National Grid ESO in Great Britain [14], PJM [15], ISO New England [16], MISO [17], CAISO [18], NYISO [19], AESO [20], Transpower New Zealand [21], and OCCTO in Japan [22]. This is evident in planning frameworks used by While implementation details vary across jurisdictions, the common principle is that the future network should remain within acceptable operating limits following the loss of any one credible system element.

2.1.4 Time-sequential planning and the growing role of storage

A major change in recent planning practice is the increasing use of time-sequential analysis, particularly to better represent variable renewable generation, storage behavior, demand flexibility, and prolonged system stress. Traditional planning methods often relied on a small number of static snapshots, peak-demand cases, or seasonal test conditions. While such abstractions remain useful, they are less capable of capturing phenomena such as:

- multi-hour renewable droughts,
- storage charging and discharging across time,
- inter-regional dependence during prolonged low-wind conditions,
- renewable curtailment and congestion patterns, and
- ramping and commitment stress associated with thermal retirements.

The rise of energy storage has made this limitation especially important. Storage affects both adequacy and network utilization in inherently time-linked ways; its contribution cannot be represented fully by simple capacity assumptions alone. In practice, however, many planning processes still treat storage imperfectly. Some represent storage only as a net load modifier or simplified dispatchable resource, while others capture operational behavior in upstream market or adequacy models but not in the transmission planning optimization itself. This creates a methodological gap between the increasing importance of storage and the level of temporal detail available in many planning models.

Current industry practice is therefore moving toward hybrid approaches: representative-period planning models for tractable long-term optimization, supplemented by chronological adequacy or production-cost assessments to recover temporal realism. This is increasingly seen as a practical compromise between model fidelity and computational tractability.

2.1.5 International comparison of security and temporal scenario treatment in planning

This section examines how selected system operators incorporate system security and represent temporal scenarios in planning. Table 2.1 summarizes the differences in the planning methodologies.

Table 2.1 Security treatment in transmission planning across different system operators

OPERATOR	PLANNING FRAMEWORK	SECURITY TREATMENT	TEMPORAL & SCENARIO TREATMENT
Australia (AEMO) [11]	Integrated System Plan (ISP)	Preventive N-1 security considered as a binding planning requirement under credible contingencies	Scenario-based, multi-year horizons with representative operating conditions
North America (NERC) [12], [23]	Transmission Planning (TPL) Standards	Mandatory performance requirements under defined contingency categories	Planning horizons with stressed system conditions and seasonal cases
Europe (ENTSO-E) [13]	Ten-Year Network Development Plan (TYNDP)	N-1 security applied within scenario-driven network development and cross-border assessment	Multi-scenario, long-term planning with regional aggregation
Great Britain (NESO) [14]	Modelling Methods How we model FES: NESO pathways to Net Zero	Security and operability embedded in coordinated onshore–offshore planning	Pathway-based planning with staged network development
PJM (USA) [15]	Regional Transmission Expansion Plan (RTEP)	Reliability-driven planning with security constraints embedded in expansion studies	Near- and long-term planning windows with defined test conditions
ISO New England (ISO-NE) [16]	Regional System Plan (RSP)	Security and reliability criteria applied to identify transmission needs	Forward-looking planning under seasonal and peak conditions
Japan (OCCTO) [22]	Cross-regional network development planning / Network Codes (network use & planning provisions)	Network planning and operation provisions defined in national Network Codes; OCCTO planning work explicitly references N-1-related arrangements as part of network access design.	Multi-year system planning and disclosure processes; supply-plan aggregation and forward-looking reliability checks.
New Zealand (Transpower) [21], [24]	Transmission Planning Report 2025	Core grid planned/operated to N-1 standard for credible contingencies; N-1 described as maintaining a satisfactory state following any one credible contingency.	Forward-looking grid planning and investment assessment using stressed conditions and scenario-based studies.
Canada (AESO – Alberta) [25]	Alberta Optimal Transmission Planning Framework – Methodology and Process 2026	Reliability standards and criteria for transmission planning are documented in AESO planning criteria; includes deterministic performance criteria aligned with contingency-based planning requirements.	Planning studies defined with explicit criteria/assumptions for system conditions and study cases over planning horizons.

Taken together, current industry practice shows a clear convergence toward security-constrained, scenario-based, and increasingly time-aware planning. At the same time, the transition to high-renewable, storage-rich power systems is exposing the limits of traditional deterministic and snapshot-based methods. This provides the methodological motivation for planning frameworks that combine tractable long-term optimisation with more detailed operation, security constraints and adequacy assessment.

2.2 Current Tools and Platforms for System Planning

Modern system planning is implemented through a toolbox of complementary software platforms rather than a single all-purpose model. This reflects the fact that long-term planning must balance several competing requirements: economic efficiency, network security, reliability, decarbonization, storage integration, and computational tractability. In practice, system operators and planners combine capacity expansion models, production cost tools, power-flow and contingency analysis software, adequacy models, and detailed operational simulators to evaluate future development pathways. The specific mix of tools varies across jurisdictions, but a common pattern is evident: market and resource evolution are often analyzed in chronological dispatch tools, while network security and transmission feasibility are assessed in separate planning and simulation environments.

A key reason for this multi-tool approach is that no single platform can simultaneously deliver high-fidelity network physics, full chronological operation, large-scale scenario analysis, storage inter-temporal behavior, and tractable long-term optimization for systems the size of the NEM, North American interconnections, or pan-European networks. As a result, industry practice has converged on linked workflows in which different tools are used at different stages of the planning process.

2.2.1 Main classes of tools used in system planning

Current planning workflows generally rely on four broad classes of modelling platforms.

- Capacity expansion and long-term planning tools, used to determine broad investment pathways for generation, storage, and sometimes transmission under different scenarios.
- Production cost and market simulation tools, used to represent time-sequential dispatch, congestion, storage cycling, curtailment, and operational stress conditions.
- Network simulation and contingency assessment tools, used to verify power-flow feasibility, voltage performance, and contingency behavior under intact and outage conditions.
- Resource adequacy and operational simulation tools, used to assess probabilistic reliability, unserved energy risk, and short-term operating feasibility.

These categories overlap in function, and many planning studies involve iterative transfer of data and assumptions between them. A long-term planning model may identify a candidate transmission pathway, a production cost tool may test its dispatch implications, and a detailed network model may then verify whether the resulting transfers remain secure under N-1 conditions.

2.2.2 Industry use of commercial tools

Among commercial tools, PLEXOS is one of the most widely used platforms for long-term system analysis. It is used by utilities, market bodies, consultants, and some system operators for capacity expansion, production cost modelling, market simulation, and scenario analysis. In planning workflows, PLEXOS is particularly valuable for representing chronological dispatch, storage operation, renewable variability, fuel costs, and congestion patterns over long horizons. It has been used in major planning studies, including large-scale transmission and resource assessments, because it can capture the interaction between generation, storage, and transmission at system scale. However, its strengths are primarily in economic and chronological system modelling, rather than full high-fidelity security-constrained transmission expansion with explicit network contingency modelling. In many practical workflows, PLEXOS is therefore used upstream of transmission security assessment, with outputs such as dispatch traces, congestion indicators, and stressed conditions passed to network-specific tools for detailed contingency validation [26].

Other commercial planning and simulation environments are also widely used. PROMOD [27], TARA [28], PSSE (PSS®E) [29], PowerWorld [30], DIgSILENT PowerFactory [31], PSCAD [32], EMTP-RV [33], RTDS/RSCAD [34], GE Vernova PlanOS [35], and similar tools are central to detailed transmission analysis because of their strong representation of AC network physics, contingency behavior, voltage performance, and dynamic response. These are the tools typically relied upon for engineering validation, connection studies, and regulatory-grade security assessment. Their limitation is that they are less suited to solving large strategic planning optimization problems across many scenarios and multi-year horizons. They are essential for technical verification but are generally not the sole engine for long-term expansion optimization.

In North America, planning bodies such as PJM, MISO, CAISO, ISO New England, and NYISO rely on combinations of production-cost models, power-flow tools, and custom reliability planning workflows rather than a single universal platform. Their planning processes are heavily shaped by NERC transmission planning standards, which require performance to be assessed over defined contingency categories and stressed conditions. This generally leads to toolchains where chronological system behavior and resource assumptions are studied separately from network contingency verification.

In Europe, planning under ENTSO-E's TYNDP is supported by a combination of market simulation, scenario analysis, and network assessment tools across national and regional TSOs. The European context adds the complexity of cross-border flows, coordinated market modelling, and heterogeneous national data and software environments, which further reinforces the need for interoperable multi-tool workflows.

In Australia, AEMO's planning practice similarly reflects a toolbox-based approach. The ISP integrates long-term scenario development, market and dispatch modelling, engineering analysis, and security-oriented planning assessment. Chronological simulations are used to characterize system behavior and derive planning conditions, while detailed network studies are used to confirm technical feasibility and system security. This broader pattern is representative of international practice: long-term planning is not performed in one model alone, but through coordinated use of multiple analytical platforms.

2.2.3 Open-source tools and their growing role

Historically, planning has relied on proprietary tools, but a growing ecosystem of open frameworks now integrated system planning. The main potential of open-source tools lies in several areas:

- Transparency: model assumptions and formulations can be inspected directly rather than treated as black boxes.
- Reproducibility: studies can be rerun, audited, and extended more easily.

- Flexibility: planners can adapt formulations to include storage, representative periods, custom security constraints, or scenario-specific structures.
- Interoperability: tools within common ecosystems, particularly Julia-based ones, can exchange data and results more consistently.
- Accessibility: research groups, public agencies, and smaller system operators can build advanced workflows without dependence on proprietary licensing structures.

A key advantage of open-source tools is their modularity and extensibility. Frameworks such as MATPOWER [36], pandapower [37], and OpenDSS [38] provide well-established capabilities for steady-state analysis, optimization, and distribution studies, while newer platforms such as NLR's Sienna [39] ecosystem packages like PowerSimulations.jl, and PowerSimulationsDynamics.jl enable scalable, high-resolution chronological simulations suitable for modern grids with high shares of inverter-based resources. Further NLR developments such as ReEDS (capacity expansion) [40], PRAS (resource adequacy) [41], and HELICS (integrated co-simulation platforms for transmission–distribution analysis) [42] also support long-term planning under uncertainty and high renewable penetration. Here, the LANL-ANSI's PowerModels serve as basis of core formulations for the power system models and seamlessly adapted by the Sienna ecosystem of tools.

Adoption by system operators is emerging but remains selective. Notably, RTE has actively invested in open-source development through the PowSyBl framework under LF Energy, using it for grid analysis and security assessment workflows [43] . GridPath is another open platform developed and maintained by Sylvan Energy Analytics for integration across capacity expansion, production cost, and resource adequacy analyses for planning and asset valuation applications. It's Users and contributors include Portland General Electric, Seattle City Light, Ava Community Energy, Valley Clean Energy, Pacific Northwest National Laboratory, Lawrence Berkeley National Laboratory, Grid-India, Environment and Climate Change Canada, Telos Energy, Energy Strategies, First Principles Advisory, Strategen, UCSB CET Lab, World Resources Institute, and Prayas Energy Group, among others [44]. Similarly, European collaboration initiatives such as PyPSA [45] ecosystem involve German Research Foundation and TSOs in open modelling efforts, demonstrating growing institutional engagement. Collaborative platforms like the Global Power System Transformation Consortium further highlight coordinated workflows using multiple open-source tools across organizations under Pillar 5 - Open Data & Tools [46]. Also, 50Hertz is developing the Modular Control Centre System, a new open-source grid control platform to enable 100% renewable integration with German TSOs [47].

Despite this progress, open-source tools are not yet a full replacement for commercial platforms in operational environments. Barriers include validation requirements, regulatory acceptance, legacy workflows, and the need for robust user support. However, their role is expanding rapidly in research, scenario analysis, and increasingly in pre-operational planning studies. Open-source approaches enable shared datasets, transparent methodologies, and cross-institutional collaboration capabilities that are critical for planning under deep uncertainty and high VRE penetration.

Overall, open-source tools are transitioning from research-oriented platforms to credible components of industry-grade planning workflows, with strong potential to complement and in some areas, gradually replace traditional proprietary software.

3 Time-sequential Modelling Framework for Security-Constrained Transmission Expansion Planning

This section presents the Security-Constrained Transmission Network Expansion Planning (SCTNEP) model developed as an open-source Julia Package iPlan.jl in this study. The model is intended to support long-term transmission planning under conditions of structural change, increasing variability, and tightening security requirements. Its central objective is to identify transmission development pathways that remain operationally feasible and security-compliant across a wide range of future system conditions, while maintaining overall economic efficiency.

3.1 Model Overview

The SCTNEP model is formulated over a multi-year planning horizon and is intended to capture both structural changes in the power system and their operational consequences. The planning horizon is discretized into annual decision stages, reflecting the way transmission investment decisions are made and reviewed in practice. Each stage comprises of a representative time-series based multi-period optimization of system structure combined with a detailed characterization of operational behavior within that year. Figure 3.1 illustrates the overall SCTNEP framework adopted in this work.

Time-series inputs form the temporal foundation of the model. Representative traces of demand, variable renewable generation, fuel prices, and hydrological conditions are used to describe system behavior within each planning year. These traces are selected to preserve key temporal correlations, such as the coincidence of high demand and low renewable output or prolonged periods of sustained generation imbalance. By retaining these correlations, the model avoids understating network stress that may arise under realistic operating conditions. The detailed procedure adapted to determine representative time-series are explained in Section 4.2.

The generation and storage portfolio are specified exogenously for each planning year, based on assumed commissioning and retirement schedules. This evolving portfolio reflects expected changes in the resource mix and defines the operational flexibility available to the system at each stage. Treating generation development as an input rather than a decision variable allows the SCTNEP model to focus explicitly on the role of transmission in enabling secure system operation, consistent with the scope of transmission planning studies.

The transmission network is represented using a synthetic, realistic-scale dataset SNEM2000 that captures network topology, electrical parameters, and the spatial distribution of load and generation. This representation supports large-scale analysis while maintaining sufficient structural detail to model inter-regional transfers, congestion patterns, and the utilization of major transmission corridors. The use of a synthetic network also enables transparent and reproducible analysis without reliance on confidential system data. In addition to physical system data, the model incorporates economic parameters, reliability standards, and security criteria. Security requirements are primarily defined with reference to critical contingency events, with an emphasis on N-1 security and selected higher-order contingencies where they materially affect long-term planning outcomes. These criteria establish the minimum level of system robustness that transmission investments must deliver.

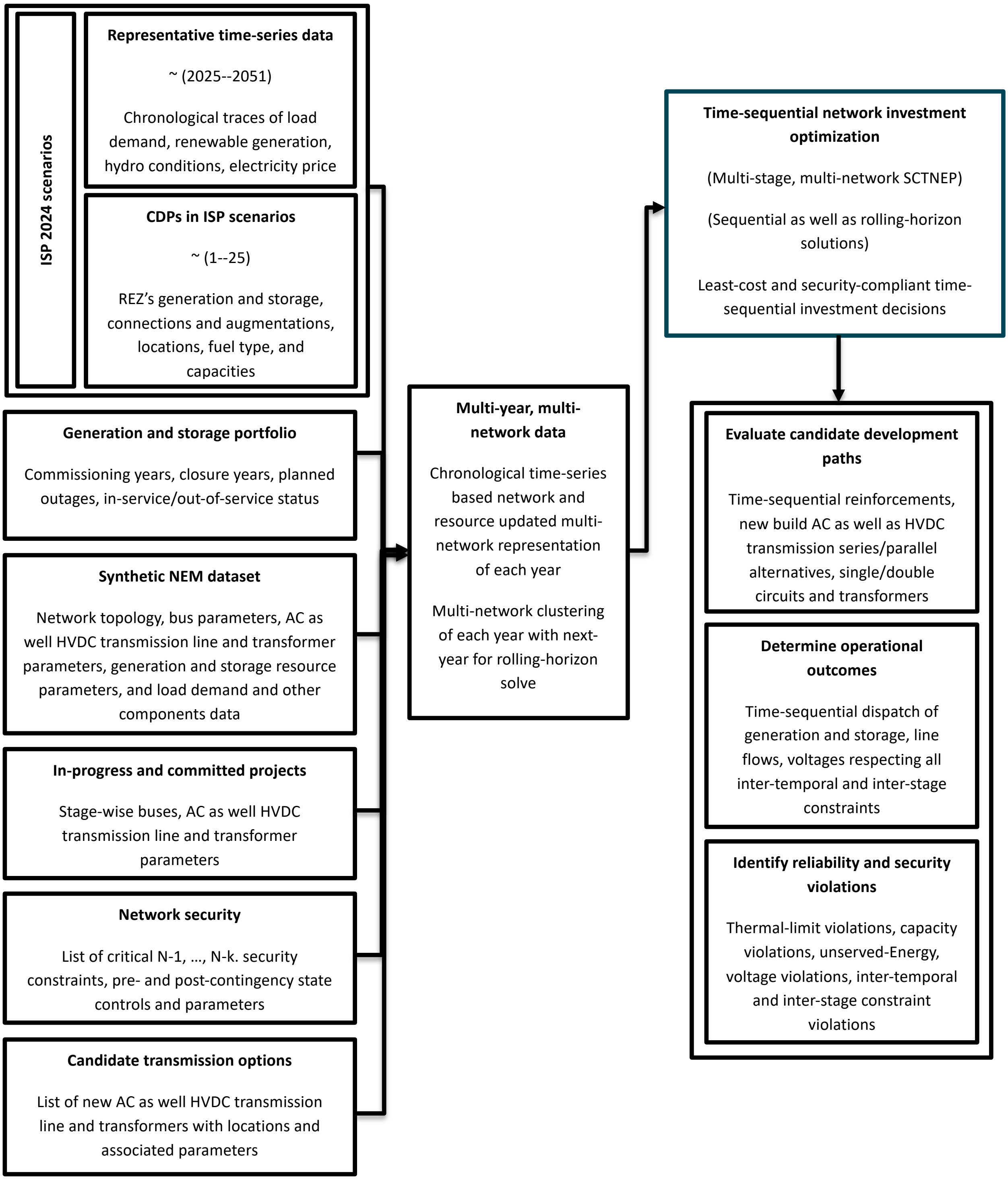


Figure 3.1 Overview of the SCTNEP modelling workflow

Candidate transmission options are defined prior to optimization and represent feasible investment actions available to planners. These options may include new AC as well as HVDC transmission corridors, capacity upgrades of existing assets, or alternative network configurations. Each candidate is characterized by its technical parameters, investment cost, and implementation constraints. By restricting investment decisions to a predefined candidate set, the model aligns with practical planning processes, where feasible options are identified through engineering assessment before being evaluated economically.

The generation expansion is represented exogenously based on CDPs defined in AEMO's ISP 2024 scenarios, with REZs providing generation location, fuel-type and capacity trajectories, along with associated network augmentations required to enable their connection. Similarly, for each CDP, storage location, type, and capacity trajectories are also modelled as inputs.

In addition, in-progress and committed projects are treated as model inputs rather than decision variables, reflecting their high likelihood of delivery and regulatory commitment. In the NEM context, this includes major transmission developments such as EnergyConnect (Stages 1 and 2) and Marinus Link (Stage 1), as well as committed generation and storage assets. Fixing these investments allows the optimization to focus on incremental decisions beyond the committed pipeline while maintaining consistency with current planning frameworks.

The model captures the interaction between transmission capability, dispatch feasibility, congestion, losses, security constraints, and storage operation, while avoiding endogenous optimization of generation, storage, and REZ candidate expansion. This is consistent with the role of transmission planning in the ISP context, where many non-network developments are already specified within the planning scenarios.

Mathematically, the model is formulated as a multi-stage, multi-network mixed-integer optimization problem that supports alternative linear, convex as well as non-convex formulations of power network physics, including base and contingency stages, with explicit modelling of inter-stage generation and storage operation under pre- and post-contingency conditions while capturing the inter-temporal dynamics of generation and storage operation. Moreover, the framework also accommodates network reduction techniques to enable tractable analysis of large-scale systems. The implementation further supports multiple temporal resolutions through representative scenario traces and enables both fully time-sequential and rolling-horizon optimization solves. This flexibility allows the model to balance computational tractability with the need to capture chronological system behavior and operational constraints.

The outputs of the planning model are the network development outcomes justified under each scenario and subsequent CDPs. These include the selected AC and HVDC augmentations, the timing and configuration of new or upgraded circuits, indicative investment cost, changes in network power-flow patterns, congestion relief, and system-level effects such as losses and transfer capability. The model therefore provides the transmission planning layer required to translate ISP scenario assumptions into technically feasible network pathways that can be compared consistently across futures.

3.2 Time-sequential operational modelling

A key feature of the SCTNEP model is its use of time-sequential operational modelling to evaluate transmission investments under realistic operating conditions. For each planning year, the system is represented as a sequence of chronological operating states derived from the representative time-series inputs. This approach allows the model to capture both short-duration stress events and extended periods of constrained operation.

Within each operating state, system operation is evaluated subject to power balance, network constraints, and resource availability. At a conceptual level, this can be interpreted as a constrained dispatch problem in which generation and storage resources are scheduled to meet demand while respecting transmission limits. Although the SCTNEP framework does not rely on a single explicit dispatch formulation, this abstraction provides a consistent basis for assessing operational feasibility across different network configurations.

Time-sequential modelling enables the identification of operational challenges that are not visible in static or snapshot-based planning approaches. These include sustained congestion on key corridors, changes in power flow direction driven by variable renewable output, and periods where limited operational flexibility amplifies the impact of network constraints. By exposing the network to these conditions, the model provides a more informative assessment of how transmission investments perform over time.

From a planning perspective, the time-sequential representation also supports the identification of recurring patterns of network stress. Rather than responding to isolated extreme events, the SCTNEP model highlights structural issues that persist across many operating hours or seasons. This distinction is critical for long-term planning, as it helps differentiate between issues that require transmission reinforcement and those that may be addressed through operational measures.

3.3 Modelling of security constraints, security assessment and identification of critical contingencies

Security assessment is embedded directly within the time-sequential operational evaluation. For each operating state, the model assesses system performance under a defined set of contingency conditions representing critical outages of network elements. These contingencies reflect planning standards and operational experience and are selected to capture the most relevant threats to secure system operation.

From a planning standpoint, security compliance can be interpreted as a feasibility condition: a given network configuration is acceptable only if all relevant operational limits are satisfied under both intact conditions and the specified contingencies. These limits may include thermal ratings of transmission elements, voltage bounds, stability-related margins, and supply adequacy requirements. Failure to meet these criteria indicates that the network is structurally insufficient to support secure operation under the assumed system conditions.

When security violations are identified, they are treated as indicators of network weakness rather than transient operational anomalies. The SCTNEP model records the location, timing, and severity of violations across the time-sequential horizon, allowing planners to understand not only where the network fails, but also under what conditions and how frequently these failures occur.

By embedding security assessment within the operational evaluation, the model ensures that security considerations influence planning decisions throughout the analysis. This contrasts with sequential approaches, where security is checked only after candidate investments have been selected, potentially leading to late-stage redesign or inefficient reinforcement.

The SCTNEP model is also applied to the base case (i.e., without candidate transmission options) to systematically identify critical contingencies. This is achieved by evaluating the resulting operational performance across all considered scenarios and recording violations such as thermal overloads, voltage limit breaches, and stability-related constraints. By benchmarking these violations against scenario-specific conditions, the approach enables the screening and ranking of contingencies based on their severity and frequency, thereby providing a robust basis for prioritizing network reinforcements and operational interventions. More detail is presented in Chapter 5.

3.4 Evaluation of candidate transmission investments

Candidate transmission options are evaluated based on their effectiveness in mitigating identified security and operational violations. For each option, the model examines how changes to the network alter power flow patterns, relieve congestion, and improve security margins across the full set of operating states and contingencies.

At a conceptual level, the evaluation process compares alternative network configurations in terms of their total system cost and their ability to meet defined security requirements. While the detailed optimization formulation may involve discrete investment choices and continuous operational variables, the underlying planning objective can be described as selecting transmission investments that minimize overall cost subject to security feasibility constraints.

This evaluation framework allows the SCTNEP model to distinguish between investments that provide narrowly targeted relief and those that deliver broader system-wide benefits. It also supports the comparison of alternative development strategies, such as staged reinforcements versus larger, upfront investments. These comparisons are particularly important in long-term planning, where the timing of investment can be as critical as its location.

In addition, evaluating candidate options within a time-sequential and security-aware framework helps reveal interactions between different reinforcements. Investments that appear effective in isolation may provide diminishing returns when combined, while others may deliver complementary benefits. The SCTNEP model provides a structured basis for identifying such interactions.

3.5 Rolling-horizon, multi-year investment logic

Transmission investment decisions in the SCTNEP model are determined with a rolling-horizon foresight, on year-by-year basis reflecting the incremental nature of transmission planning in practice. For each planning year, the SCTNEP model identifies a set of investments that satisfies security requirements across the associated time-sequential operating states while minimizing total system cost.

Investments selected each year are carried forward into subsequent years and incorporated into the evolving network model. This inter-temporal linkage ensures that early decisions directly influence future operational performance and subsequent investment requirements, capturing path dependency whereby timely reinforcements can defer or eliminate later needs. The rolling-horizon formulation further enables adaptive planning by optimizing decisions for the current year in conjunction with a limited forward-looking window of future years. As the horizon advances incrementally, past decisions are fixed, preventing redundant re-optimization and maintaining computational efficiency while preserving consistency in the investment pathway.

By applying this logic consistently across the planning horizon, the SCTNEP model produces a time-ordered transmission development pathway. This pathway provides insight into both the sequencing and timing of network reinforcements required to maintain secure operation, supporting strategic decision-making over the long term.

Within the broader planning framework described in Section 3.1, the SCTNEP model serves as the analytical core that links scenario assumptions to actionable transmission investment decisions. By integrating time-sequential operation and security assessment, the model provides a transparent mechanism for evaluating how transmission development affects both operational feasibility and system cost.

Importantly, the SCTNEP framework establishes security as a binding planning constraint rather than a secondary consideration. This positioning ensures that investment decisions are informed by realistic operational performance and that the resulting transmission development pathways are robust to credible disturbances.

The integrated structure of the SCTNEP model also provides a consistent foundation for subsequent analysis. Extensions to projected assessment of system adequacy, sensitivity studies, and uncertainty analysis can be developed on top of the same modelling framework, enabling coherent assessment of long-term system risk and resilience.

3.6 Interoperability with resource adequacy assessment models

The proposed framework is implemented in Julia as iPlan.jl, which enables seamless interoperability with the available open-source tools for projected assessment of system adequacy developed within Julia. In particular, the high-fidelity representation of network constraints, operational limits, and chronological dispatch within the planning model facilitates a consistent transfer of outputs to adequacy assessment models such as PowerSystems.jl, PowerSimulations.jl and probabilistic frameworks including PRAS.jl. All adequacy assessment studies are implemented in iPASA.jl.

A key advantage lies in the use of compatible data structures and shared modelling paradigms. Network topology, generator characteristics, storage behavior, and time-series data produced by the planning model can be readily mapped into adequacy simulations without extensive post-processing or data transformation. This reduces modelling inconsistencies and preserves the integrity of assumptions across planning and adequacy studies. The chronological and security-constrained nature of the planning outputs further enhances adequacy assessments by providing realistic operational trajectories, including congestion patterns, curtailment, and reserve utilization.

The interoperability is strengthened by the open-source nature of the modelling ecosystem. Tools developed in Julia share common data abstractions, enabling modular workflows where planning outputs can directly feed into adequacy models. This integrated approach supports iterative analyses, where adequacy insights (e.g., loss-of-load risk or capacity shortfalls) can inform subsequent planning iterations.

Overall, this interoperability enables a coherent end-to-end workflow from transmission planning to resource adequacy assessment, improving transparency, reducing duplication of effort, and supporting more robust decision-making.

4 Open High-Fidelity Synthetic NEM Dataset, Mapping to ISP Inputs and Scenarios for SCTNEP

4.1 Synthetic NEM dataset

Initially, the S-NEM2300-bus model was developed as a first-of-its-kind synthetic grid with a longitudinal structure based on the Australian NEM. Its structure is derived from a detailed PSS®E network model, with generation, transmission, and load data assigned through statistical obfuscation techniques. The resulting HYPERSIM model is stored in a relational database, enabling flexible modification of topology and parameters, and is compatible with both real-time EMT platforms and high-performance offline simulation environments. This foundation was then extended in [48], [49] to support optimal power flow studies through the inclusion of additional operational parameters such as thermal limits. Network reduction techniques are applied, including the removal of ideal lines or circuit breakers and the merging of cascading lines connected via degree-2 buses, resulting in a reduced network of approximately 2000 buses while preserving key electrical characteristics. The resultant dataset was released publicly as Synthetic-NEM2000-bus dataset [50]. Further enhancements in [51] incorporated HVDC interconnectors, improving the representation of inter-regional power transfers and emerging transmission technologies, while [52] introduced security-constrained optimal power flow formulations related parameters to capture contingency-aware operation and system reliability considerations. Building on these developments, the present work updates the generation mix, adds storage assets in the base case and further extends the dataset to incorporate planning-oriented features such as candidate augmentations, long-term scenarios, and investment variables, enabling its application to transmission expansion planning and integrated operational-planning studies.

The core network model used in this project is based on this high-fidelity Synthetic-NEM2000-bus dataset[12]. As an open synthetic representation of the NEM, SNEM provides a practical and reproducible foundation for large-scale transmission planning studies without relying on confidential operational data. For the present work, this is particularly important, as the study requires a network model that is sufficiently detailed to capture inter-area and inter-state transfer behavior, while remaining flexible to accommodate long-horizon planning inputs and scenario-dependent system changes. The detailed network topology is presented in Figure 4.1.

The dataset retains the main structural features required for transmission planning, including buses, AC transmission lines, transformers, and HVDC interconnectors. This level of network detail is necessary for the present study, which focuses on SCTNEP rather than on highly aggregated regional approximations. At the same time, the dataset remains AC-feasible, which makes it suitable not only for the optimization framework used in this project, but also for follow-on steady-state and more detailed dynamic studies. In that sense, SNEM is used here not simply as a convenient synthetic test case, but as a physically meaningful network base for security-aware planning analysis.

[12] https://github.com/csiro-energy-systems/Synthetic-NEM-2000bus-Data

A key feature of the version used in this project is its regional structure. The network is organized into 15 planning areas across the five NEM states, namely NNSW, CNSW, SNW, SNSW, WNV, MEL, SEV, NQ, CQ, GG, SQ, NSA, CSA, SESA, and TAS, with these areas grouped into the five state-level categories of NSW, VIC, QLD, SA, and TAS. This structure is important because it provides enough spatial detail to examine inter-area stress and transfer bottlenecks, while remaining compatible with the ISP planning inputs. It supports both area- and state-level interpretation of results, accommodating inputs defined at different spatial resolutions in later modelling stages.

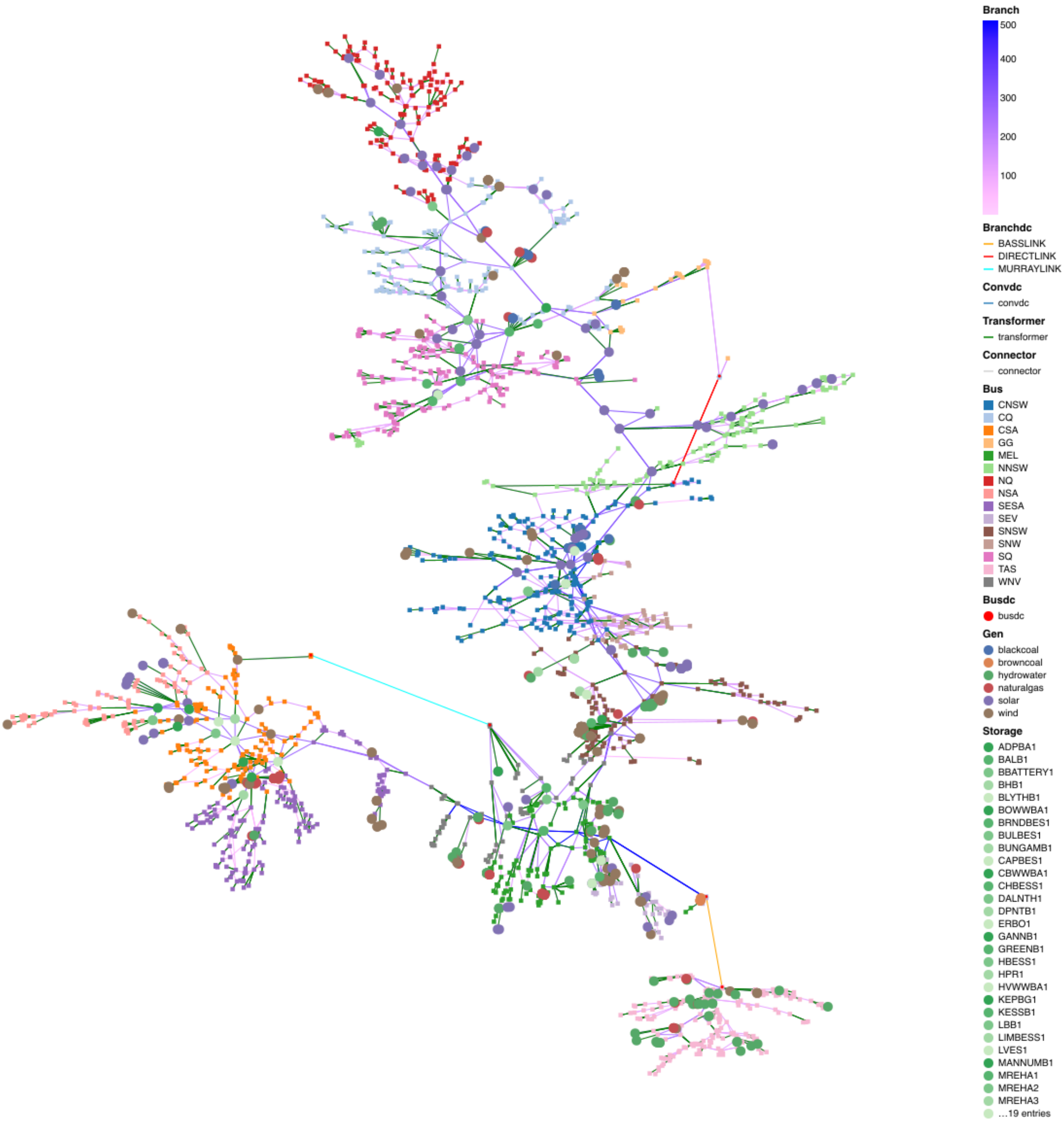


Figure 4.1 Detailed electrical topology of the SNEM with regional structure. The 2000-bus transmission network represents buses, transmission branches, transformers, and DC links with generation and storage resources.

For this study, the SNEM base case has been updated using AEMO's recent generation and storage information as of October 2025 [53]. This update gives the synthetic dataset a current operational basis for future planning. In practice, the dataset is therefore not treated as a purely static synthetic benchmark, but as an updated network starting point to which future retirements, additions, and network developments can be applied in a consistently. This positions the SNEM representation as the primary modelling platform, underpinning the planning analysis conducted in this study.

The update process includes the use of DUID-based identifiers and related mapping information for generation and storage assets. This is useful in a synthetic planning model because it provides a consistent way to align updated asset records with the underlying network representation while preserving traceability as the system evolves across scenarios and years. In the present context, this helps maintain consistency between the transmission network model and the changing resource portfolio, particularly when future committed and planed updates are introduced.

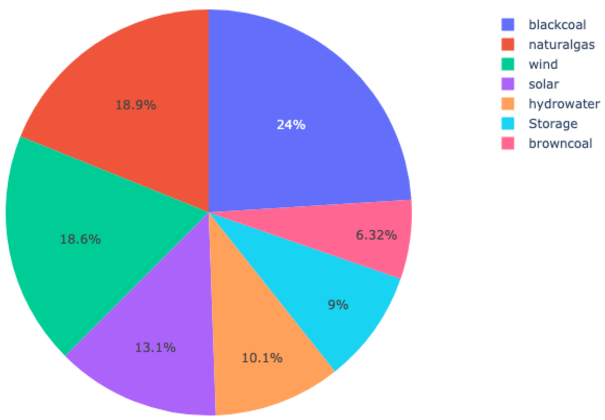
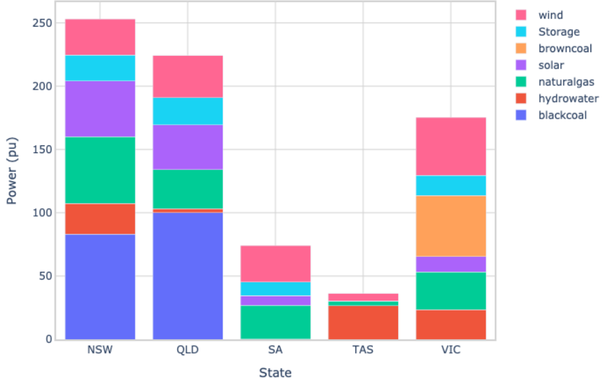


Figure 4.2 Overall energy-mix of the SNEM base case



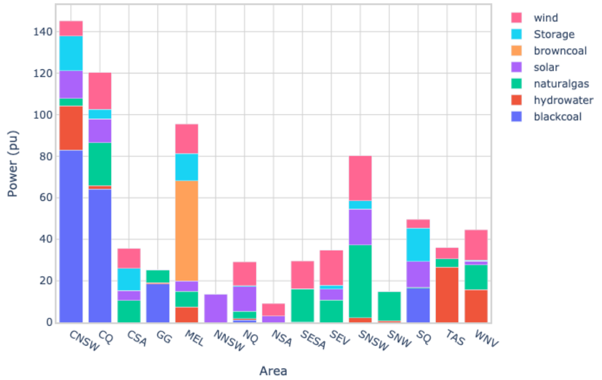


Figure 4.3 State-wise energy-mix of the SNEM base case

Figure 4.4 Regional energy-mix of the SNEM base case

The overall energy-mix of the SNEM base case is shown in Figure 4.2. The dataset also reflects the broad diversity of the present-day NEM resource mix across the 5 states and 15 regions as shown in Figures 4.3 and 4.4 respectively. Although the purpose of this subsection is not to provide a detailed review of each state, it is important to note that the network base spans coal-dominated regions undergoing transition, hydro-rich Tasmania, and areas with significant existing or emerging wind, solar, and storage development. This diversity is one of the reasons why the dataset is suitable for long-horizon planning studies. It provides a more realistic starting point than a spatially uniform or heavily simplified system model, and it allows later planning inputs to be introduced on top of a network that already captures the broad structural differences across the NEM.

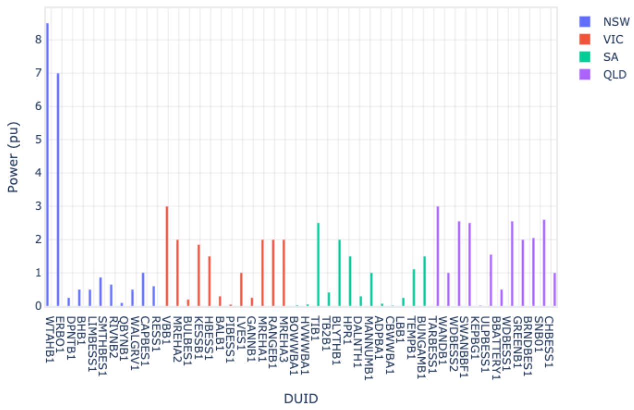


Figure 4.5 State-wise storage power discharge of the SNEM base case

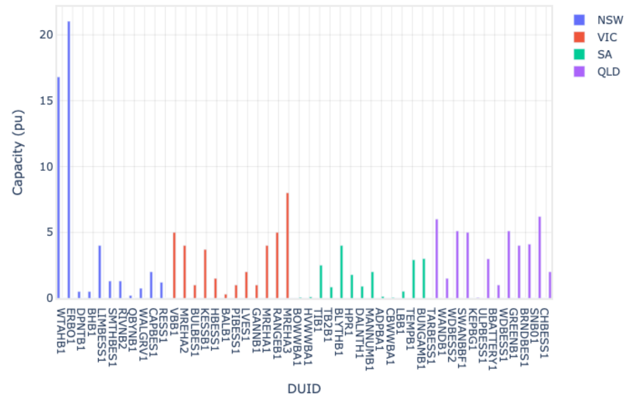


Figure 4.6 State-wise storage capacity of the SNEM base case

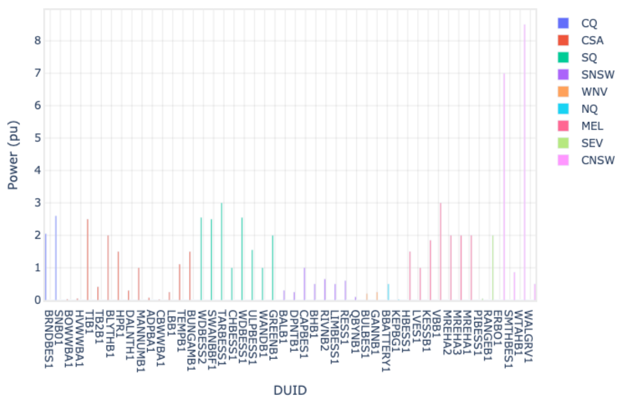


Figure 4.7 Regional storage power discharge of the SNEM base case

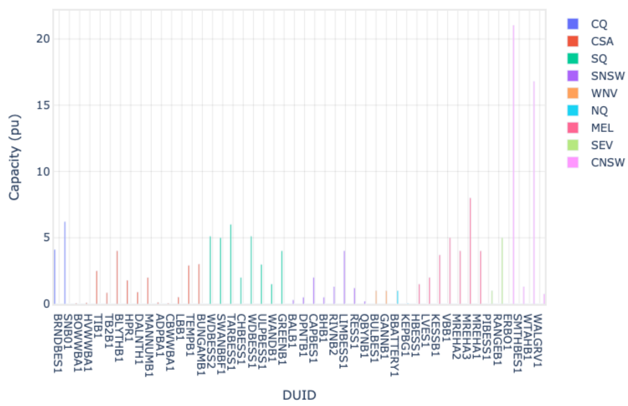


Figure 4.8 Regional storage capacity of the SNEM base case

The state- and region-wise storage portfolios represented in the SNEM base case are illustrated in Figures 4.5, 4.6, 4.7 and 4.8. The dataset captures the spatial distribution and diversity of storage technologies across the 5 states and 15 regions, reflecting both existing deployments and emerging developments. It is important to note that the representation includes a mix of storage characteristics, ranging from large-scale, long-duration assets to shorter-duration and distributed systems. This diversity enhances the suitability of the dataset for long-horizon planning studies, as it enables the assessment of storage behavior under varying system conditions and operational requirements. Consequently, the dataset provides a realistic basis for incorporating future storage expansion and operational strategies, while preserving the heterogeneity of the NEM.

Overall, SNEM provides the network foundation for the modelling undertaken in this project. It combines an open and detailed transmission representation with a spatial structure that aligns well with planning applications, and it provides a consistent platform on which later planning study inputs can be incorporated. The following subsections therefore move from the dataset itself to the way in which these additional inputs are represented and mapped for the multi-period SCTNEP cases used in the remainder of the report.

4.2 Mapping ISP inputs and scenarios to SNEM dataset

The SNEM dataset described in the previous subsection provides the network base for the present study. On this basis, ISP-derived planning inputs are mapped to the adopted SNEM representation to construct the yearly datasets used in the SCTNEP analysis. This mapping is required because the source inputs are supplied in different forms and at different spatial and temporal resolutions, while the planning model requires a consistent representation of demand, renewable availability, resource changes, and network developments within the adopted 15-area structure.

The mapping process combines several input classes. For each ISP scenario, chronological load demand and renewable generation traces are aligned to the adopted SNEM spatial structure and prepared at the temporal resolution used in the study. CDP information is translated into REZ generation, storage, and transmission developments that are compatible with the adopted network representation. Together with other inputs, these steps produce mapped yearly planning datasets that retain consistency between the host network, the time-varying operating inputs, and the evolving system configuration.

4.2.1 Representation of ISP scenario's load demand and generation traces

This section presents a systematic framework for extracting representative daily profiles from long-term half-hourly demand and renewable generation time series. The objective is to construct three characteristic operating conditions for each year. Worst-case, best-case, and typical-case day are generated to capture extreme and average system states relevant for power system planning.

The proposed methodology combines statistical aggregation with optimization-based selection, enabling the identification of daily profiles that represent distinct operational regimes while maintaining computational tractability. This approach aligns with established practices in time-series reduction and representative period selection in energy system modelling, e.g., clustering, representative days, and extreme scenario extraction [54], [55], [56], [57].

Data preparation and aggregation

Half-hourly demand and renewable generation data (solar and wind) from the Integrated System Plan (ISP) are first cleaned and restricted to the analysis period of 2025—2051. For each time step, total system demand D_t and total renewable generation R_t are computed as

$$D_t = \sum_{i=1}^{N_d} D_{i,t} \ , R_t = \sum_{j=1}^{N_r} D_{j,t} \ , \tag{1}$$

where N_d and N_r denote the number of demand and renewable generation regions respectively. The resulting time series are partitioned into daily segments, each consisting of 48 half-hourly intervals. Only complete days are retained to ensure consistency in subsequent analysis.

Identification of worst-case days

For each year, a stress score is calculated for every complete day to quantify the imbalance between demand and renewable supply. The daily stress score is defined as the cumulative net demand over a given day as

$$S_d = \sum_{t=1}^{48} \left(D_{t,d} - R_{t,d} \right) \ , \tag{2}$$

where $D_{t,d}$ and $R_{t,d}$ denote total demand and renewable generation at interval t on day d.

This metric captures the extent to which demand exceeds renewable supply and is consistent with the concept of net load, widely used in power system operation and planning [58]. A higher score indicates greater reliance on dispatchable generation and increased system stress. The worst-case day is defined as

$$d_{worst} = \arg\max_{d} S_d. \tag{3}$$

This corresponds to the day with the highest cumulative supply-demand imbalance, representing the most challenging operating condition within the year.

Identification of best-case days

The best-case day is identified by selecting the day with the lowest stress score as

$$d_{best} = \arg\min_{d} S_d. \tag{4}$$

This represents periods where renewable generation substantially offsets or exceeds demand. Such conditions are associated with renewable surplus, potential curtailment, and opportunities for storage utilization or energy export. Identifying these periods is critical for evaluating system flexibility requirements and renewable integration challenges [59].

Identification of typical-case days

While extreme days provide insight into boundary conditions, a typical-case day is required to characterize the central tendency of system behavior. Using the same stress score distribution S_d, the median value $\dot{S} = median(S_d)$ is computed for each year. The representative typical day is then selected as

$$d_{typical} = \arg\min_{d} \left| S_d - \dot{S} \right|. \tag{5}$$

This approach ensures that the selected day lies between the two extremes and reflects an average balance between demand and renewable generation. Compared to clustering-based approaches, this median-based selection is computationally efficient, fully interpretable, and consistent with the extreme-case framework, while still capturing the dominant system behavior [60], [61].

Output and application

The resulting worst-, best-, and typical-case daily profiles each contain 48 half-hourly intervals for every year from 2025 to 2051. These representative days are exported as separate datasets for integration into power system optimization and reliability models. Together, they capture the full spectrum of operational conditions from high-demand/low-renewable stress periods to renewable-rich surplus days and the statistically dominant normal conditions. This framework enables efficient yet comprehensive system assessment without requiring simulation of full multi-year time series.

The energy profile comparisons of the best-case, typical-case, and worst-case representative days for the three ISP 2024 scenarios in 2025 and 2051 are presented in Figures 4.10 and 4.11, respectively. Across all scenarios, a consistent relationship can be observed between the paired demand and renewable generation traces. In the worst-case and typical-case days, renewable generation remains insufficient to meet electricity demand for most of the day, indicating a strong dependence on dispatchable or backup generation sources. In contrast, during the best-case day, renewable generation exceeds demand between approximately 7 a.m. and 4 p.m., representing periods of potential surplus renewable energy that could be utilized for storage, curtailment management, or energy export. The similarity in temporal patterns across the three scenarios reflect the persistent seasonal and diurnal dynamics linking demand and renewables availability.

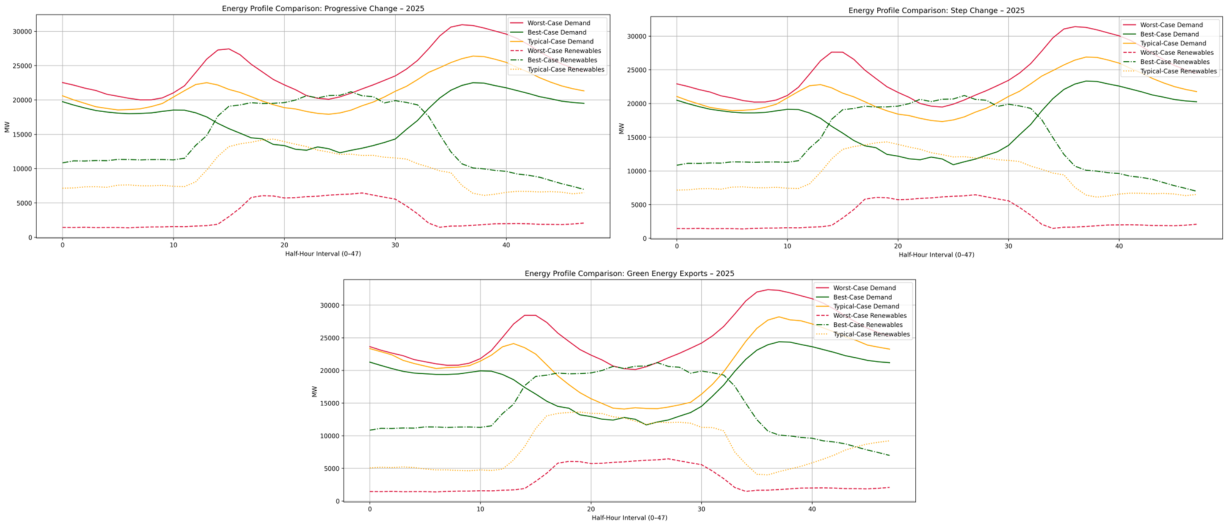


Figure 4.9 Energy profile comparison: Best, Typical and Worst representative case for three scenarios in 2025.

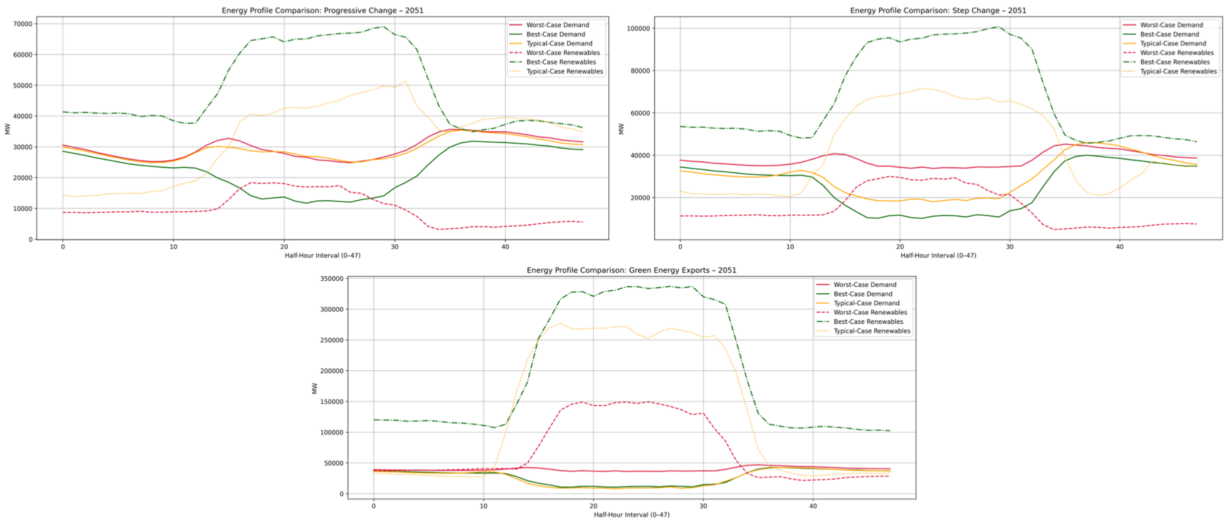


Figure 4.10 Energy profile comparison: Best, Typical and Worst case for three scenarios in 2051

As renewable penetration increases toward 2051, the overall energy profile undergoes a noticeable transformation. In the best-case conditions, renewable generation substantially exceeds demand throughout the entire 24-hour period, suggesting an abundance of renewable supply. For the typical-case, renewable generation is sufficient to meet demand between approximately 6 a.m. and 5 p.m., highlighting improved daytime resource adequacy. However, in the worst-case, renewable generation remains below demand for most of the day under the Progressive Change and Step Change scenarios. Interestingly, under the Green Energy Export scenario, renewable generation surpasses demand from around 12 a.m. to 4 p.m., indicating the impact of an ambitious renewable deployment strategy aimed at supporting large-scale energy export. These results emphasize how increased renewable capacity fundamentally shifts the balance between supply and demand, and how scenario assumptions shape the temporal dynamics of system adequacy.

The seasonal classification is further incorporated in the representative day selection. The selection is also performed independently for each season, resulting in 1 representative day per season and a total of 4 representative days for each year. This seasonal stratification ensures that key intra-annual variations in both demand and renewable resource availability are explicitly captured, including summer peak demand conditions, winter periods with reduced solar output, and transitional dynamics during autumn and spring. As a result, the reduced dataset retains a more balanced and physically meaningful representation of system behaviour across the year.

Compared to approaches that rely on a single annual representative day, this method better preserves the diversity of operating conditions while still achieving a substantial reduction in temporal dimensionality. When these four representative days are arranged sequentially and used within a chronological or time-sequential modelling framework, they can provide a more realistic approximation of inter-temporal system dynamics as shown in Figures 4.11, 4.12, and 4.13. This structure improves the representation of storage cycling, state-of-charge evolution, ramping constraints, and the interaction between demand and variable renewable generation across different seasonal regimes.

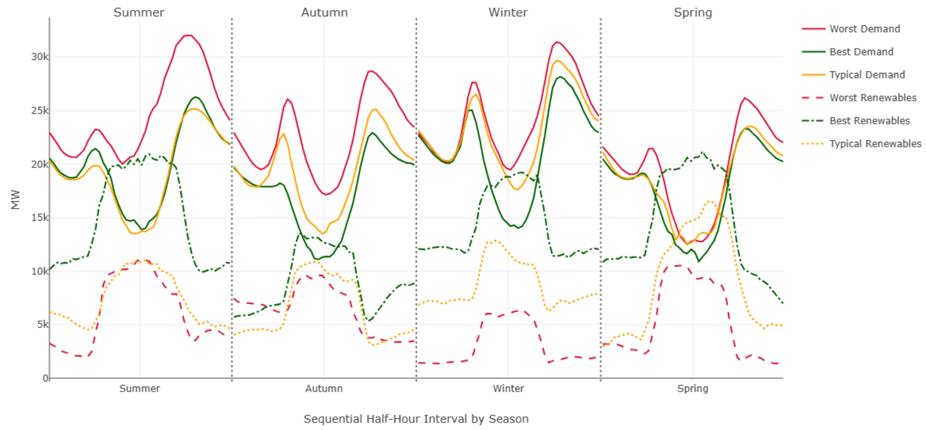


Figure 4.11 Seasonal Best, Typical and Worst representative case for the step change scenario in 2025

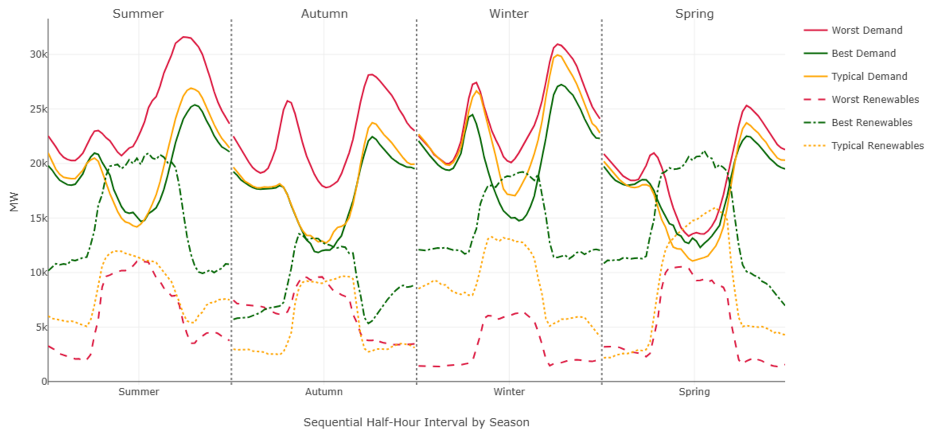


Figure 4.12 Seasonal Best, Typical and Worst representative case for the progressive change scenario in 2025

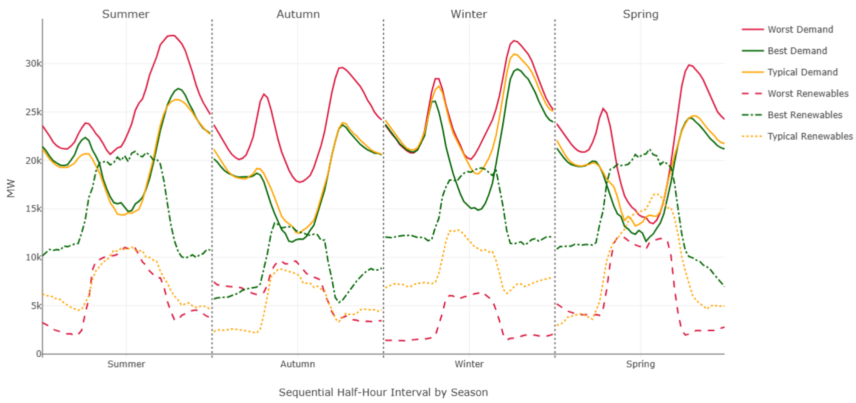


Figure 4.13 Seasonal Best, Typical and Worst representative case for the green energy exports scenario in 2025

Consequently, the SCTNEP model adopts a sequential four-day representation for each planning year, balancing computational tractability with temporal fidelity. This approach preserves key seasonal and operational characteristics while maintaining chronological consistency, enabling a more realistic assessment of storage operation, renewable integration, network utilisation, and long-term transmission investment requirements.

4.2.2 Mapping of ISP scenario's load demand and generation traces to SNEM dataset

The load demand and renewable generation traces used in this project are derived from 2024 ISP scenario inputs and then mapped to the adopted SNEM structure. This step is required because the source inputs and the planning network are not available on the same spatial basis. The adopted SNEM representation is organized into 15 planning regions or areas, whereas the available ISP inputs are provided at a mixture of state, and regional, and subregional levels depending on the parameters considered. A consistent alignment procedure is therefore needed before the traces can be introduced into the yearly planning datasets.

For demand, the adopted approach preserves the available ISP spatial information where possible and distributes allocation only where the SNEM structure is more spatially resolved than the source traces. In Queensland and New South Wales, the demand traces align with the 4 planning areas in each state. In South Australia, the available demand information is mapped to the 2 mainland planning areas used in the model. In Victoria, where the adopted SNEM structure distinguishes WNV, MEL, and SEV, the available demand trace is apportioned across these 3 areas so that the time-varying demand input remains consistent with the network representation and Tasmania is treated as a single area. In this way, the demand-side traces remain compatible with the planning network without introducing a spatial mismatch between the time-series inputs and the underlying topology.

A similar procedure is applied to renewable generation traces. In the present study, these refer to wind and solar traces derived from the ISP scenario inputs. Rather than being applied as system-wide scaling factors, the renewable traces are aligned with the adopted SNEM structure through the mapped location of generation assets. Depending on the granularity of the available source data, this alignment is carried out at state-level. The mapped wind and solar profiles are then used to represent the time-varying renewable availability associated with the corresponding generation locations in the network model. This preserves the link between the spatial distribution of renewable generation and the chronological variation of the resource itself.

Table 4.1 Summary of the spatial alignment adopted for ISP load demand and renewable generation traces to SNEM

INPUT CATEGORY	SOURCE SPATIAL BASIS	MAPPING TO ADPOTED SNEM STRUCTURE
Load demand traces in NSW	Regional traces	Aligned to the four adopted NSW planning areas
Load demand traces in QLD	Regional traces	Aligned to the four adopted QLD planning areas
Load demand traces in SA	Subregional traces	Mapped to the two adopted mainland SA planning areas
Load demand traces in VIC	Subregional traces	Apportioned across WNV, MEL, and SEV
Load demand traces in TAS	Regional traces	Directly aligned to TAS
Wind generation traces	State-based traces	Assigned to mapped renewable generation locations in the SNEM
Solar generation traces	State-based traces	Assigned to mapped renewable generation locations in the SNEM

The spatial treatment adopted for demand and renewable traces is summarized in Table 4.1. As shown there, the mapping is not uniform across all input classes. Demand traces are aligned primarily through the adopted planning-area structure, with apportioning used where the network model is more spatially resolved than the source input.

Load demand and renewable traces are assigned through the scaling of available load and renewable resources within the SNEM representation based on the yearly representative traces. This results in a multi-year, multi-network SNEM planning dataset. This alignment is important because network stress depends not only on the total level of demand or renewable output, but also on where these quantities are located and how they change over time. By mapping the ISP-derived representative traces to the SNEM, the workflow preserves the connection between time-varying operating conditions and network behavior.

4.2.3 Mapping of ISP scenario's CDPs to SNEM

CDPs are used in this project as structured planning inputs that describe how major future developments may unfold including REZs, their generation capacities, locations and corresponding network augmentations as well as storage assets, their capacities, and locations. Overall, 25 CDPs are defined under each ISP scenario providing alternative future development pathways. The CDP inputs are mapped to the multi-year, multi-network SNEM planning dataset on yearly basis, as the given capacities evolve in a yearly fashion.

Tables 4.2 and 4.3 present example mappings of REZ generation and storage assets, respectively, under the ISP Step Change Scenario CDP10, illustrating the automated process implemented within iPlan.jl. In Table 4.2, generators are assigned to their corresponding REZ and connected to appropriate buses within the SNEM, with connecting substations identified and matched to network buses through the automated mapping procedure. Where the network topology requires it, for instance, where a new REZ connection point does not coincide with an existing bus, new buses and transformers are automatically installed to maintain AC feasibility. Table 4.3 follows an analogous approach for storage units, which are mapped by state and linked to relevant network buses. In both cases, generation and storage capacities evolve on a yearly basis as specified in the CDP inputs, ensuring that the planning dataset accurately reflects the temporal trajectory of infrastructure deployment across the simulation horizon.

Table 4.2 Example REZ's automated generation mapping in SNEM under ISP Step Change Scenario CDP10

REZ	GENERATOR INDEXES	GENERATOR NAMES	GENERATOR BUSES
N1	594, 595	pv_N1_1, wtg_N1_1	2030
N10	654	owtg_N10_1	2034
N11	655	owtg_N11_1	2035
N2	637, 638, 639, 640, 641, 642, 643, 644, 645, 646, 647, 648, 649, 650, 651	pv_N2_1, pv_N2_2, pv_N2_3, pv_N2_4, pv_N2_5, pv_N2_6, pv_N2_7, wtg_N2_1, wtg_N2_2, wtg_N2_3, wtg_N2_4, wtg_N2_5, wtg_N2_6, wtg_N2_7, wtg_N2_8	2032
N3	596, 597, 598, 599, 600, 601, 602, 603, 604, 605, 606, 607, 608, 609, 610, 611, 612, 613	pv_N3_1, pv_N3_2, pv_N3_3, pv_N3_4, pv_N3_5, pv_N3_6, pv_N3_7, pv_N3_8, pv_N3_9, wtg_N3_1, wtg_N3_2, wtg_N3_3, wtg_N3_4, wtg_N3_5, wtg_N3_6, wtg_N3_7, wtg_N3_8, wtg_N3_9	1815
N4	652, 653	pv_N4_1, wtg_N4_1	2033
N5	614, 615, 616, 617	pv_N5_1, pv_N5_2, pv_N5_3, wtg_N5_1	1393
N6	618, 619, 620	pv_N6_1, pv_N6_2, wtg_N6_1	1393
N7	621, 622	pv_N7_1, wtg_N7_1	1393
N8	623, 624	pv_N8_1, wtg_N8_1	719
Q1	493, 494, 495	pv_Q1_1, wtg_Q1_1, wtg_Q1_2	965
Q2	496, 497, 498, 499, 500, 501, 502	pv_Q2_1, pv_Q2_2, wtg_Q2_1, wtg_Q2_2, wtg_Q2_3, wtg_Q2_4, wtg_Q2_5	1655
Q3	503, 504	pv_Q3_1, wtg_Q3_1	849
Q4	505, 506, 507, 508, 509, 510, 511, 512, 513	pv_Q4_1, pv_Q4_2, pv_Q4_3, pv_Q4_4, pv_Q4_5, wtg_Q4_1, wtg_Q4_2, wtg_Q4_3, wtg_Q4_4	1790
Q5	514, 515	pv_Q5_1, wtg_Q5_1	685
Q6	625, 626, 627, 628, 629, 630, 631, 632, 633, 634, 635, 636	pv_Q6_1, pv_Q6_2, pv_Q6_3, pv_Q6_4, pv_Q6_5, pv_Q6_6, pv_Q6_7, pv_Q6_8, wtg_Q6_1, wtg_Q6_2, wtg_Q6_3, wtg_Q6_4	2031
Q7	516, 517, 518, 519, 520	pv_Q7_1, pv_Q7_2, pv_Q7_3, wtg_Q7_1, wtg_Q7_2	2018
Q8	521, 522, 523, 524, 525, 526, 527, 528, 529, 530, 531, 532, 533, 534, 535	pv_Q8_1, pv_Q8_2, pv_Q8_3, pv_Q8_4, pv_Q8_5, pv_Q8_6, pv_Q8_7, pv_Q8_8, wtg_Q8_1, wtg_Q8_2, wtg_Q8_3, wtg_Q8_4, wtg_Q8_5, wtg_Q8_6, wtg_Q8_7	2019
Q9	536, 537	pv_Q9_1, wtg_Q9_1	2020
S1	538, 539	pv_S1_1, wtg_S1_1	177
S10	666	owtg_S10_1	2038
S2	540, 541, 542	pv_S2_1, pv_S2_2, wtg_S2_1	2021
S3	543, 544, 545, 546, 547	pv_S3_1, wtg_S3_1, wtg_S3_2, wtg_S3_3, wtg_S3_4	1551
S4	548, 549	pv_S4_1, wtg_S4_1	2022
S5	550, 551, 552, 553	pv_S5_1, pv_S5_2, pv_S5_3, wtg_S5_1	1778
S6	554, 555	pv_S6_1, wtg_S6_1	264
S7	556, 557	pv_S7_1, wtg_S7_1	2023
S8	558, 559	pv_S8_1, wtg_S8_1	2024
S9	560, 561	pv_S9_1, wtg_S9_1	2025
T1	562, 563	pv_T1_1, wtg_T1_1	2026
T2	564, 565	pv_T2_1, wtg_T2_1	2027
T3	566, 567, 568, 569	pv_T3_1, wtg_T3_1, wtg_T3_2, wtg_T3_3	2028
T4	667	owtg_T4_1	2039
T5	668	owtg_T5_1	2040
V1	570, 571	pv_V1_1, wtg_V1_1	2029
V2	572, 573, 574, 575, 576, 577	pv_V2_1, pv_V2_2, pv_V2_3, pv_V2_4, pv_V2_5, wtg_V2_1	654
V3	578, 579, 580, 581	pv_V3_1, wtg_V3_1, wtg_V3_2, wtg_V3_3	811
V4	582, 583, 584, 585, 586, 587	pv_V4_1, wtg_V4_1, wtg_V4_2, wtg_V4_3, wtg_V4_4, wtg_V4_5	811
V5	588, 589, 590	pv_V5_1, wtg_V5_1, wtg_V5_2	1004
V6	591, 592, 593	pv_V6_1, pv_V6_2, wtg_V6_1	600
V7	656, 657, 658, 659, 660, 661, 662, 663, 664	owtg_V7_1, owtg_V7_2, owtg_V7_3, owtg_V7_4, owtg_V7_5, owtg_V7_6, owtg_V7_7, owtg_V7_8, owtg_V7_9	2036
V8	665	owtg_V8_1	2037

Table 4.3 Example automated storage mapping in SNEM under ISP Step Change Scenario CDP10

STATE	STORAGE INDEXES	STORAGE NAMES	STORAGE BUSES
NSW	54, 55, 56, 57, 58, 59	Snowy 2.0_NSW, Deep storage_NSW, Medium storage_NSW, Shallow storage_NSW, Coordinated CER storage_NSW, Passive CER storage_NSW	1719, 1910, 1427, 733, 1367, 170
QLD	69, 70, 71, 72, 73, 74	Borumba_QLD, Deep storage_QLD, Medium storage_QLD, Shallow storage_QLD, Coordinated CER storage_QLD, Passive CER storage_QLD	1374, 955, 636, 1843, 1389, 1903
SA	49, 50, 51, 52, 53	Deep storage_SA, Medium storage_SA, Shallow storage_SA, Coordinated CER storage_SA, Passive CER storage_SA	402, 404, 809, 270, 649
TAS	60, 61, 62, 63	Deep storage_TAS, Medium storage_TAS, Coordinated CER storage_TAS, Passive CER storage_TAS	702, 1517, 1366, 154
VIC	64, 65, 66, 67, 68	Deep storage_VIC, Medium storage_VIC, Shallow storage_VIC, Coordinated CER storage_VIC, Passive CER storage_VIC	1532, 614, 803, 1591, 1269

Table 4.4 Example REZ's AC transmission extensions in the SNEM under ISP Step Change CDP10[13]

REZ	SS1	SS2	kV	MW/cct	Ccts	Length (km)	Tfmr	r [Ohm]	x [Ohm]	b [S]	Fbus	Tbus
Q1	Ross	Chalumbin	275	1073	4	245	N	6.125	46.1814	0	1012	965
Q2	Mt. Fox	Kidston	275	800	2	190	N	4.75	35.8142	0	88	1655
Q3	Ross	Strathmore	275	800	2	200	N	5	37.6991	0	1012	849
Q4	Strathmore	Nebo	275	800	2	150	N	3.75	28.2743	0	849	1790
Q5	Lilyvale	Baccardine	275	1073	2	340	N	8.5	64.0885	0	824	685
Q7	Mt England	NA	275	1073	2	175	N	4.375	32.9867	0	306	0
Q8	Middleridge	NA	275	1500	2	0	Y	0	7.5625	0	697	0
Q9	Gladstone	NA	500	1520	4	200	N	5	37.6991	0	296	0
S1	Heywood	South East	500	1520	4	91	N	2.275	17.1531	0	811	177
S2	Robertstown	NA	275	1500	2	0	Y	0	7.5625	0	280	0
S3	Robertstown	Davenport	275	950	2	209	N	5.225	39.3956	0	280	1551
S4	Blythe West	NA	275	900	2	151	N	3.775	28.4628	0	800	0
S5	Davenport	Cultana	275	950	2	62	N	1.55	11.6867	0	1551	1778
S6	Davenport	Leigh Creek	275	950	2	235	N	5.875	44.2965	0	1551	264
S7	Davenport	NA	275	950	2	139	N	3.475	26.2009	0	1551	0
S8	Cultana	NA	275	950	1	254	N	6.35	47.8779	0	1778	0
S9	Cultana	NA	275	950	1	254	N	6.35	47.8779	0	1778	0
T1	George Town	NA	220	600	2	80	N	2	15.0796	0	1507	0
T2	Hampshire	NA	220	533	3	80	N	2	15.0796	0	1162	0
T3	Sheffield	NA	220	533	3	30	N	0.75	5.65487	0	5	0
V1	South Morang	NA	330	1500	2	0	Y	0	10.89	0	245	0
V2	Ballarat	Kerang	500	1520	4	200	N	5	37.6991	0	535	654
V3	Ballarat	Mortlake	500	1520	4	200	N	5	37.6991	0	535	811
V4	Sydenham	Mortlake	500	1520	4	214	N	5.35	40.338	0	1532	811
V5	Hazelwood	BASSLINK	500	1520	4	65	N	1.625	12.2522	0	1535	1004
V6	Ballarat	Shepparton	500	1520	4	200	N	5	37.6991	0	535	600
N1	Tamworth	Wellington	330	500	2	100	N	2.5	18.8496	0	1022	1815
N1	Wellington	NA	330	500	2	150	N	3.75	28.2743	0	1815	0
N3	Wollar	Wellington	500	725	4	80	N	2	15.0796	0	712	1815
N5	Wagga	Darlington Pt	500	800	3	152	N	3.8	28.6513	0	758	1393
N6	Bannaby	Wagga	500	1520	2	259	N	6.475	48.8203	0	668	1393
N7	Bannaby	Wagga	500	1520	2	360	N	9	67.8584	0	668	1393
N8	Williamsdale	Cooma	132	169	1	81	N	2.025	15.2681	0	1451	719

[13] Asset locations are determined using the coordinates of their connecting buses, while approximate locations for newly added buses are assigned through the automated process implemented in iPlan.jl.

Table 4.5 Example REZ's DC transmission extensions in the SNEM under ISP Step Change CDP10

REZ	Existing SS1	Existing SS2	New SS1	New SS2	kV	MW/ckt	Ccts	Length (km)	r [Ohm]	Fbus	Tbus
Q6	Calvale	NA	NA	Wandan South	320	1500	1	250	3.75	1762	0
N2	Armidale	NA	NA	Bayswater	500	1000	2	230	3.45	581	0
N4	Bannaby	NA	NA	Broken Hill	500	1000	2	850	12.75	668	0
MARINUS	Hazelwood	Burnie	NA	NA	500	750	2	255	3.825	1112	1507
N10	Munmorah	NA	NA	Offshore	330	750	2	50	0.75	50	0
N11	Bannaby	NA	NA	Offshore	330	750	2	65	0.975	760	0
V7	Loy Yang	Giffard	NA	Offshore	500	2500	2	150	2.25	245	0
V8	Portland	NA	NA	Offshore	500	500	1	60	0.9	311	0
S10	Mt Gambier	NA	NA	Offshore	132	500	1	50	0.75	251	0
T4	Heybridge	NA	NA	Offshore	110	500	1	50	0.75	1071	0
T5	George Town	NA	NA	Offshore	220	500	1	50	0.75	1832	0

Tables 4.4 and 4.5 detail the corresponding transmission extensions required to support these generation and storage additions in the SNEM. Table 4.4 covers AC transmission extensions associated with REZ connections in the SNEM identifying the new lines, cables, or transformer upgrades needed to dispatch generation from each zone to the broader network, while Table 4.5 presents DC transmission extensions, which are particularly relevant for long-distance bulk power transfer corridors anticipated through REZs as well as offshore wind generation connections through submarine DC cables. These network augmentations are likewise automated within iPlan.jl, with new transmission elements introduced as required to accommodate expanding REZ capacities and to preserve network integrity across each planning year. Comprehensive detail of the full automated mapping methodology, including the logic governing bus assignment, transformer insertion, and transmission extension, is available in the iPlan.jl technical documentation.

4.2.4 Mapping of generation retirement of SNEM dataset

As explained in Section 4.1, the SNEM generation and storage information is updated using AEMO’s NEM October 2025 Generation Information [53]. Consistent with this approach, generator retirements are also systematically incorporated during the construction of the multi-year, multi-network planning dataset within iPlan.jl, drawing on AEMO's Generating Unit Expected Closure Year - October 2025 [62]. The retirement mapping process ensures that generating units are removed from the active network inventory in the planning year that corresponds to their expected closure date as published by AEMO. This is critical for maintaining temporal consistency across the multi-year dataset, as the progressive withdrawal of ageing thermal and legacy generation assets has a direct bearing on system adequacy assessments, REZ sizing decisions, and network augmentation requirements in later planning years. Retiring a unit at the correct point in time ensures that neither its capacity contribution nor its network connection is erroneously retained beyond its expected operational life, which would otherwise distort planning outcomes by overstating available generation or understating the need for replacement capacity.

Where a generating unit's expected closure year falls within the simulation horizon, iPlan.jl automatically flags and deactivates the corresponding unit at the beginning of the relevant planning year. This deactivation removes the unit's capacity from dispatch availability and ensures appropriate assessment of associated network connections.

4.3 Mapping of In-progress Transmission Infrastructure Projects to SNEM Dataset

In-progress and committed projects are also systematically incorporated during the construction of the multi-year, multi-network planning dataset within iPlan.jl on yearly basis. Table 4.6 presents an example list of in-progress and committed AC transmission projects that are currently under development within the NEM, representing near-term network augmentations that are already approved and progressing through construction or late-stage planning. These projects are incorporated into the SNEM planning dataset as fixed infrastructure additions, appearing in the network from their respective commissioning years onward across all planning scenarios.

Table 4.6 Example list of in-progress and committed projects mapping to SNEM

Project	Name	F.Area	T.Area	Fbus	Tbus	kV	F MW	B MW	km	Ccts	Tfmr	Year
N1	EnergyConnect Stage 1	WNV	NSA	734	0	300	1000	1000	300	2	N	2025
N1	EnergyConnect Stage 1 (xfmr)	NSA	NSA	280	0	[300 275]	1000	1000	0	2	Y	2025
N1	EnergyConnect Stage 2	WNV	SNSW	734	0	220	1000	1000	800	2	N	2027
N1	EnergyConnect Stage 2 (xfmr)	SNSW	SNSW	758	0	[220 330]	1000	1000	0	2	Y	2027

4.4 Mapping of Candidate Transmission Infrastructure Projects to SNEM Dataset

The candidate AC and DC transmission infrastructure projects are presented in Tables 4.7 and 4.8 respectively, that are considered as potential network augmentations within the SNEM planning framework. These candidate projects represent the investment decision space available to the optimization engine in iPlan.jl that is, the set of transmission options from which optimal expansion plans are selected based on cost, feasibility, and system adequacy across the planning horizon.

The mapping of candidate transmission projects to the SNEM dataset is handled entirely through an automated process within iPlan.jl and represents one of the most important and technically involved features of the planning tool. The automated nature of this process is essential given the scale of the candidate set and the need for consistency across all planning scenarios, CDP variants, and simulation years.

For AC candidate lines, iPlan.jl first checks the voltage level of each candidate project against the existing SNEM bus inventory. Where the specified voltage level of a candidate line does not correspond to an existing bus at the relevant terminal substation, a new bus is automatically created at the appropriate voltage level, and a new transformer is inserted to connect it to the existing network. This ensures that every candidate line can be electrically integrated into the network in a voltage-consistent manner without requiring manual network editing for each candidate.

Critically, for multi-circuit candidate lines, iPlan.jl adds each circuit as an individual line element within the network model. This means that a candidate project specified as a double- or triple-circuit line is represented as two or three separate but parallel line objects in the dataset. This modelling approach is deliberate and significant: it allows the optimization to make granular investment decisions not only on whether to build a particular corridor, but also on how many circuits to construct. The number of circuits to commit is therefore itself an optimization decision variable, enabling the model to identify least-cost build-out levels that match system needs without over- or under-investing in transmission capacity.

Table 4.7 List of candidate AC transmission options

Opt ID	Name	From	To	kV	MW/cct	Ccts	km	Tfmr	Cost $M	r [Ohm]	x [Ohm]	Fbus	Tbus	ID
NQ-CQ1	275 kV NQCQ double-circuit	CQ	NQ	275	1100	2	350	N	1,239	2.3140	18.5123967	1012	563	3081, 3082
NQ-CQ2	500 kV NQCQ backbone double-circuit	CQ	NQ	500	3000	2	750	N	4,184	0.3936	4.92	1012	563	3087, 3088
CQ-GG1	275 kV rebuild double-circuit	CQ	GG	275	500	2	200	N	1,300	1.3223	10.5785124	1445	1282	3089, 3090
CQ-SQ1	275 kV double-circuit shunt reactors	SQ	CQ	275	900	2	250	N	820	1.6528	13.2231405	1445	636	3091, 3092
CQ-SQ2	275/500 kV double-circuit shunt reactors	SQ	CQ	500	3150	2	250	Y	3,287	0.3936	4.92	1445	636	3097, 3098
CQ-CQ1	275 kV double-circuit	CQ	CQ	275	3000	2	350	N	1,250	1.3223	10.5785124	1445	296	3099, 3100
SQS-Q1	276 kV double-circuit	SQ	SQ	275	3000	2	350	N	1,250	1.3223	10.5785124	636	1056	3101, 3102
SQ-NNSW1	QNI 330 kV single-cct	NNSW	SQ	330	900	1	461	N	1,893	1.2699	12.6997245	1510	581	3103
SQ-NNSW2	QNI 330 kV double-circuit	NNSW	SQ	330	850	2	461	N	2,518	1.2699	12.6997245	1510	581	3104, 3105
SQ-NNSW3	500 kV backbone	NNSW	SQ	500	2500	1	616	N	5,260	0.4928	6.16	1510	581	3108
NNSW-CNSW1	CNSW NNSW Option 1 (500/330 kV Hub 1 upgrades)	NNSW	CNSW	300	3000	2	100	N	1,834	0.18	2.25	581	1022	3113, 3114
NNSW-CNSW2	CNSW NNSW Option 1 (500/330 kV Hub 1 upgrades)	CNSW	CNSW	500	3000	2	100	Y	1,995	0.18	2.25	1929	712	3117, 3118
NNSW-CNSW3	CNSW NNSW Option 2 (Hub5 switching + Bayswater)	NNSW	NNSW	500	3000	2	100	Y	1,993	0.1736	2.17	581	661	3121, 3122
CNSW-SNW1	CNSW SNW Option 1 Northern 500 kV ring	CNSW	SNW	500	5000	2	105	N	926	0.084	1.05	436	1632	3123, 3124
CNSWS-NW2	CNSW SNW Option 2 Southern Loop	CNSW	SNW	500	4500	2	114	N	1,550	0.0912	1.14	1179	668	3125, 3126
CNSWS-NW3	CNSW SNW Option 2b Bannaby Sydney West	CNSW	SNW	330	1200	1	200	N	277	0.5509	5.50964187	1299	1528	3127
CNSWS-NW4	CNSW SNW Option 2b Bannaby Sydney West	CNSW	SNW	330	1200	1	200	N	277	0.5509	5.50964187	1299	648	3128
CNSW-SNSW1	CNSW SNSW Option 1 Humelink	CNSW	SNSW	500	2000	2	360	Y	4,892	0.288	3.6	668	758	3131, 3132
SNSW-WNV1	SNSW WNV Option 1 VNI West	SNSW	WNV	500	2000	2	481	Y	4,592	1.2699	12.6997245	758	283	3137, 3138
WNV-MEL1	WNV MEL Option 1 VNI West	WNV	MEL	500	2000	2	156	Y	2,360	1.2699	12.6997245	283	535	3143, 3144
MEL-SEVIW1	MEL SEV Option 1 Western Renewables Link	MEL	SEV	500	2000	2	184	Y	2,180	1.2699	12.6997245	535	1532	3147, 3148
MEL-WNV1	Western Victoria Grid Reinforcement	MEL	WNV	500	2000	1	225	N	2,580	1.2699	12.6997245	1532	1891	3149
MEL-WNV2	Western Victoria Grid Reinforcement	MEL	WNV	500	2000	1	210	N	2,250	1.2699	12.6997245	1891	537	3151
MEL-WNV3	Western Victoria Grid Reinforcement	MEL	WNV	500	2000	1	150	N	2,350	1.2699	12.6997245	537	311	3153
SESA-CSA1	Mid North South Australia REZ Expansion	SESA	CSA	275	1000	2	200	N	930	1.3223	10.5785124	358	1808	3154, 3155
SESA-CSA2	Mid North South Australia REZ Expansion	SESA	SESA	275	1000	2	120	N	930	1.02231	9.5785124	1808	280	3156, 3157
WNA-SESA1	Heywood Reinforcement	WNA	SESA	275	1000	1	285	N	980	1.05231	10.0578512	810	177	3158
TAS1	Waddamana–Palmerston Upgrade	TAS	TAS	220	1000	1	182	N	1,350	1.00231	10.0057851	1507	1137	3159
TAS2	Waddamana–Palmerston Upgrade	TAS	TAS	220	1000	1	166	N	1,000	1.00231	10.0057851	1507	44	3160
TAS3	Waddamana–Palmerston Upgrade	TAS	TAS	220	1000	1	130	N	1,100	1.00231	10.0057851	1137	702	3161
TAS4	Waddamana–Palmerston Upgrade	TAS	TAS	220	1000	1	102	N	1,000	1.00231	10.0057851	44	702	3162
TAS5	Waddamana–Palmerston Upgrade	TAS	TAS	220	1000	1	225	N	1,250	1.00231	10.0057851	702	1517	3163
CNSW-CNSW1	CNSW 330 kV Reinforcement Upgrade	CNSW	CNSW	330	1000	1	220	N	2,050	1.06997	12.6997245	751	1855	3164
CNSW-SNW5	CNSW SNW Option 1b Transformer Upgrade	CNSW	SNW	330	1000	1	100	Y	980	0.288	3.6	50	1342	3166
CNSW-SNSW2	CNSW SNSW Option 2 330 kV Reinforcement	CNSW	SNSW	330	1000	1	225	N	1,000	1.0699	12.6997245	751	1766	3167

Table 4.8 List of candidate DC transmission options

Opt ID	Name	F.Area	T.Area	kV	MW/cct	Ccts	km	Cost $M	r [Ohm]	Fbus	Tbus
SQNNSW4	SQ NNSW Halys HVDC	SQ	NNSW	500	2000	2	765	4,279	2.24	1510	581
NNSWCNSW4	NNSW CNSW Option 4 HVDC	NNSW	CNSW	500	2000	2	280	2,544	2.8	581	1022
NNSWCNSW5	NNSW CNSW Option 5 Richmond Vale	NNSW	CNSW	500	2000	2	350	2,450	2.08	1022	1929

For DC candidate projects, the automated mapping process in iPlan.jl is correspondingly more complex, reflecting the additional components required to represent DC infrastructure within the AC network model. For each DC candidate option, iPlan.jl automatically creates the required DC buses at both terminal ends of the link, installs the AC/DC converter stations at each terminal with all required electrical parameters, and adds the DC line connecting the two converter stations. All component parameters including converter ratings, DC line resistance and capacity, and terminal bus associations are set automatically based on the candidate project specification, ensuring that each DC option is fully and consistently parameterized for use in optimal power flow and optimization calculations.

As with AC candidates, multiple DC options for a given corridor can be evaluated independently within the optimization, allowing investment decisions to reflect differences in capacity, technology, or routing between alternative DC project configurations. Together, the automated AC and DC candidate mapping capabilities of iPlan.jl ensure that the full candidate transmission investment space is accurately and consistently represented in the SNEM dataset, providing the optimization with a well-formed and electrically coherent set of expansion options from which to identify optimal network development pathways.

5 Security Assessment and Identification of Critical Contingencies

This chapter examines the system security over the planning horizon, with the objective of identifying the locations, operating periods, and critical contingencies under which the network becomes most vulnerable. The analysis establishes the pattern of system stress pre-planning under normal operation and then identifies the contingencies that most significantly disrupt system performance as the transition progresses. In this way, the analysis informs to the modelling frameworks introduced in the preceding chapters particularly, the SCTNEP.

5.1 Security Assessment under Normal Operation

To perform the SCTNEP, the multi-year, multi-network data is generated as explained in Chapter 4. It includes all the inputs integrated into the existing SNEM over the planning horizon. The inputs include, renewable generation, REZs, REZ connections, storage systems, in-progress and committed projects and retiring generation on yearly basis. This serves as a starting point for the pre-planning security assessment under both normal and contingency state operation.

In case of normal operation, although no network element is removed, the results already reveal persistent and evolving stress across the planning horizon. This is an important observation from a planning perspective, because it shows that part of the future security challenge is embedded in the changing structure of the system itself, rather than arising only when credible outages are imposed. As renewable generation expands, thermal capacity retires, and inter-regional transfer requirements evolve, the secure operating envelope becomes progressively tighter even before contingency conditions are considered.

In this subsection, system stress is characterised using unserved energy, which provides a direct and physically interpretable measure of conditions under which the selected network configuration is unable to fully supply demand within the operating constraints represented in the model. Under this interpretation, non-zero unserved load indicates that the evolving generation, storage, demand, and transfer patterns of the selected case are no longer fully compatible with feasible operation. The resulting measure is therefore useful not only for identifying the presence of stress, but also for comparing how its magnitude and location change over time. This chapter presents the analysis for the Step Change scenario only, in the interest of brevity.

Figure 5.1 shows the annual unserved energy under normal operation from 2025 to 2051, aggregated by state. The results indicate a clear temporal intensification of system stress across the planning horizon. In the earlier years, unserved energy remains relatively limited, suggesting that the selected system configuration can still accommodate the prevailing operating conditions without widespread difficulty. From the early 2030s onward, however, the magnitude of unserved energy increases more noticeably, and the growth becomes particularly pronounced in the later part of the horizon. This pattern points to a progressive tightening of the operating envelope rather than an isolated stress event in a single year. In other words, the selected planning case becomes increasingly difficult to operate securely even under normal conditions as the transition progresses.

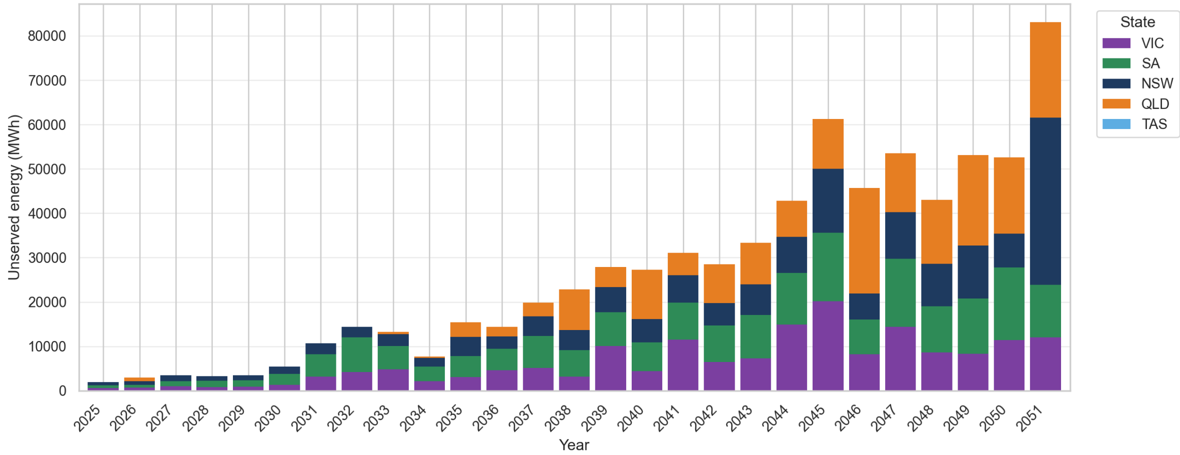


Figure 5.1 Annual unserved load under normal operation from 2025 to 2051, shown by state

The state-level composition of unserved energy provides important insight, as the burden of system stress is not uniformly distributed across the NEM and evolves over time. Tasmania and Queensland account for a substantial share of unserved load over much of the horizon, while Victoria and South Australia contribute materially during periods of elevated stress. New South Wales becomes increasingly significant in later years, particularly as total unserved energy rises toward the end of the horizon. This shifting composition indicates that the dominant pressure points are dynamic rather than fixed, reflecting changes in the generation mix, transfer requirements, and regional supply and demand balance.

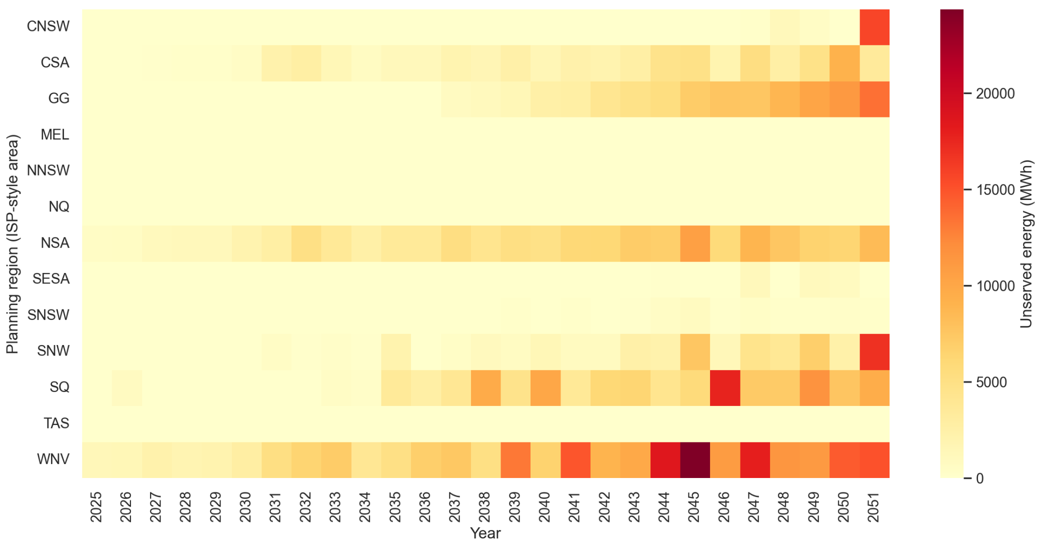


Figure 5.2 Distribution unserved load across planning regions and years for the selected case under normal operation

A more detailed spatial view of the intensity of unserved energy based on regional distribution is shown in Figure 5.2 across the planning horizon. The results confirm that stress under normal operation is spatially concentrated rather than diffusely distributed across the network. Several regions remain close to zero for most of the study horizon, whereas a smaller subset emerges as persistent hotspots. In particular, Tasmania exhibits a sustained increase in unserved energy from the early 2030s onward, remaining one of the most consistently stressed regions through the later years. SQ and SNW also become increasingly prominent in the second half of the horizon, while WNV shows repeated periods of elevated stress across multiple years. CQ remains comparatively moderate in the earlier years but intensifies sharply toward the end of the study period. By contrast, regions such as CNSW, CSA, GG, MEL, NQ, NSA, SESA, SNSW, and VIC remain comparatively less stressed for most of the horizon, even though some of them show localized increases in selected years.

Overall, the normal-operation results establish three points that are central to the remainder of the chapter. First, the selected planning case already exhibits measurable unserved energy even when all modelled network elements remain in service. Second, this stress intensifies over time rather than remaining static, indicating that the security challenge evolves with the broader generation and demand transition. Third, the resulting pressure is spatially concentrated, with particular regions and corridors contributing disproportionately to the observed unserved load. These findings establish a reference point for the selection of candidate options and provide the basis for interpreting the contingency results in the following subsection. Rather than viewing contingencies in isolation, the next stage of the analysis considers how critical contingencies interact with an already tightening system and identifies those events that most significantly worsen security performance.

5.2 Critical Contingency Screening

Having established the pattern of system stress under normal operation, the next step is to examine how that stress changes when contingencies are introduced. The purpose of this subsection is not to provide an exhaustive engineering description of every tested event, but to identify the contingencies that most significantly disrupt system performance and therefore act as the dominant security drivers from a planning perspective. In the present study, this screening is carried out by imposing each inter-area outage individually and re-evaluating system performance across the full planning horizon. The resulting comparison makes it possible to distinguish outages that produce only limited imbalance from those that expose structurally important weaknesses in the network.

Figure 5.3 provides an initial overview by comparing the worst unserved energy observed under normal operation with the range of worst unserved energy outcomes obtained across the tested N-1 contingencies. In the earlier years, the difference between the normal-operation trajectory and the post-contingency range remains relatively limited, indicating that the network retains a reasonable degree of resilience to the tested contingencies under less stressed system conditions. This behaviour is especially evident across the late 2020s, when the worst-case outcomes under contingency operation remain close to those observed under normal operation. As the horizon advances, however, the gap between the two becomes more visible and more persistent. From the early 2030s onward, a subset of contingencies begins to produce distinctly more severe outcomes than are observed under normal operation alone, and by the later years this divergence becomes sufficiently pronounced to indicate a clear increase in outage sensitivity. This result is important because it shows that contingency severity strengthens together with the broader structural transition of the system, rather than remaining fixed over time.

This transition is not monotonic in every year however; the broad pattern is unambiguous. The system does not simply become more stressed under normal operation as the horizon progresses; it also becomes increasingly sensitive to the loss of network component. In other words, a contingency that is relatively benign in the earlier years may become substantially more severe once renewable penetration deepens, transfer dependence increases, and the feasible operating margin narrows.

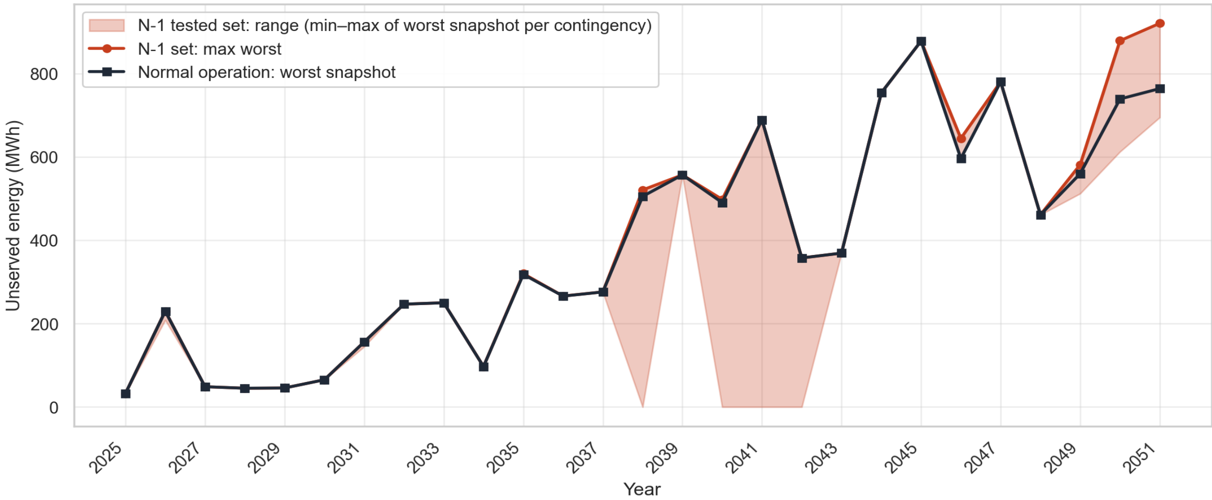


Figure 5.3 Comparison of worst snapshot unserved load under normal operation and under tested N-1 contingencies for the selected Step Change case over the 2025 to 2051 planning horizon.

An equally important feature of Figure 5.3 is that the full tested outage set does not behave uniformly. In many years, the normal-operation trajectory remains close to the lower part of the post-contingency range, and the median contingency outcome is implied to remain relatively close to the intact case. This indicates that the system is not equally sensitive to every tested outage. Instead, the most severe imbalance is driven by a relatively limited subset of contingencies that behave as clear outliers. From a planning perspective, this is a valuable result. It means that future security risk is not uniformly distributed across the outage set as a whole but concentrated in a small number of structurally significant events. As a result, the purpose of the screening is not simply to confirm that contingencies matter, but to identify which outages dominate the observed deterioration and therefore warrant particular attention in the subsequent reinforcement analysis.

Figure 5.4 provides a detailed temporal view of worst-snapshot unserved energy across the planning horizon for all tested contingencies. Three features are notable. First, trajectories are highly uneven over time, confirming that contingency severity is strongly state-dependent rather than constant. Second, only a small subset of contingencies consistently dominates the most severe outcomes, reinforcing that the security problem is concentrated around a limited number of structurally critical outages. Third, the most severe post-contingency outcomes cluster in the later planning years, particularly from the mid-2040s onward, where multiple contingencies converge toward similarly high unserved energy levels, suggesting the network becomes progressively less tolerant to the loss of key components as the system transition advances.

The figure also suggests that different contingencies exhibit different modes of severity. Some outages appear as sharp spikes in particular years, indicating periods of acute but time-specific vulnerability. Others remain repeatedly present among the most severe outcomes over a broader portion of the horizon, indicating a more persistent structural weakness. This distinction is useful because it separates contingencies associated with isolated periods of extreme stress from those that signal a recurring exposure embedded in the network structure itself. Both forms are relevant to planning, but they imply slightly different types of reinforcement response. Peak-driven contingencies highlight conditions under which the network becomes acutely vulnerable, whereas persistently severe contingencies point to corridors or interfaces whose structural importance is likely to remain high across multiple stages of the transition.

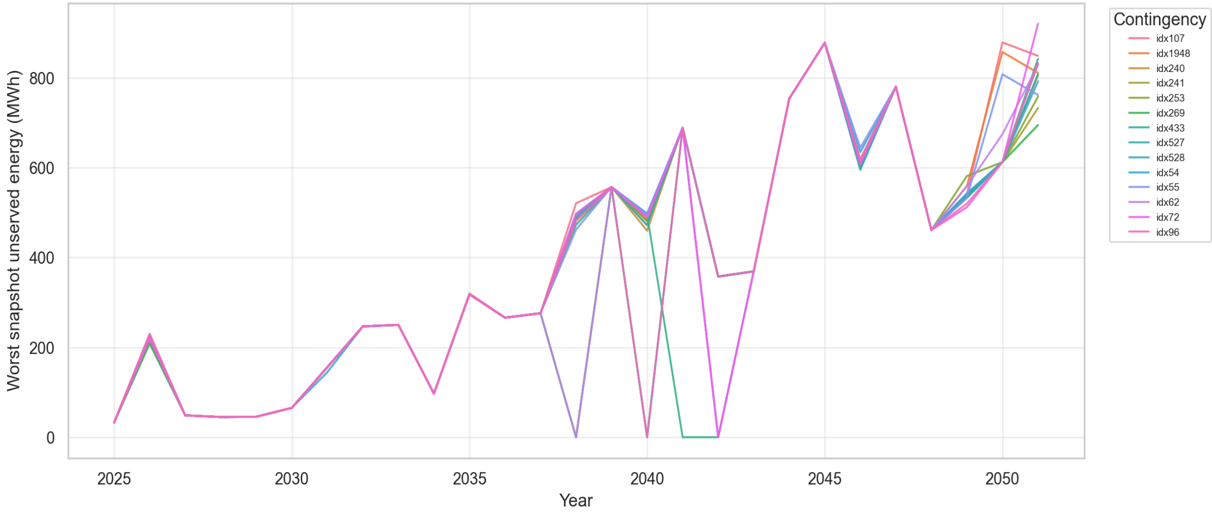


Figure 5.4 Temporal evolution of worst snapshot unserved load for the most severe tested N-1 contingencies in the selected Step Change case over the 2025 to 2051 planning horizon.

Figure 5.4 highlights the screening exercise identifying a list of severe events. It reveals which parts of the selected network remain most exposed as the transition progresses, and therefore which areas are most likely to influence the timing, scale, and composition of later reinforcement decisions. This interpretation also clarifies why contingency screening in the present study should not be understood as a stand-alone reliability exercise. The significance of a contingency is shown to depend not only on the element that is removed, but also on the broader evolution of the operating environment in which that outage occurs. For this reason, the identification of critical contingencies is best interpreted as part of a broader time-sequential planning problem. The role of the screening is to identify the outages that dominate post-contingency imbalance and to establish the security context within which the subsequent transmission planning should be performed.

6 Time-Sequential SCTNEP Results and Analysis

This chapter presents the results and analysis of the proposed SCTNEP. Building on the modelling approach and assessment framework introduced in the previous chapters, the analysis examines how transmission development pathways evolve when temporal variation, network security, and the operational behavior of energy-limited storage are represented explicitly within the planning process. It is intended not only to report model outputs, but also to interpret the planning insights that emerge from the time-sequential formulation. In particular, the results are used to examine how transmission investment needs develop over time, how these needs are reflected in the timing and location of network reinforcements, and how the representation of storage and security constraints influences the transmission pathway identified by the model.

To maintain clarity and technical focus, results are first presented for all representations of the 2024 ISP scenarios (Step Change, progressive, and Green Energy Exports). As classified in Chapter 4, the representations include seasonal and non-seasonal best-, typical-, and worse-case for each scenario resulting in total 6 representations for each scenario. This establishes a consistent basis for identifying key planning signals captured by the model, including persistent network stress, augmentation timing, and the interaction between storage dispatch and transmission constraints. The discussion then extends to comparative results selectively presented for brevity using the same analytical lens to assess how these patterns evolve under different planning conditions.

6.1 Optimal Planning Pathways

The optimal planning pathways identified across the three future 2024 ISP scenarios including Step Change, Progressive Change, and Green Energy Exports reflect fundamentally different assumptions about the pace of energy transition, the rate of demand growth, and the ambition of export-oriented renewable development. Despite these differences, the planning analysis consistently identifies a core set of transmission investments that appear across all scenario-representation combinations, and a broader set of investments whose timing and sequencing are sensitive to the specific operating conditions and development trajectories assumed. Detailed planning outcomes for all three scenarios and with seasonal as well as non-seasonal representations are provided in Tables 6.1, 6.2, and 6.3. Moreover, a graphical representation of optimal planning outcomes for Step Change scenario non-seasonal best representations indicating the new network, storage, and REZs built on top of the existing SNEM power system is shown in Figure 6.1. Note that the candidate transmission project IDs and their mapping to AC and DC branch IDs in SNEM and their investment costs are provided in Table 4.7 in Chapter 4.

6.1.1 Common investment imperatives across scenarios

Across all three scenarios, early-stage investment in inter-regional connectors and key REZ connecting infrastructure emerges consistently as a planning priority. The earliest commissioned assets notably the CNSWSNW3 and CNSWSNW4 Bannaby–Sydney West options (AC branch IDs 3127 and 3128, each at $276.5M) appear in the non-seasonal best representations of all three scenarios from 2025 onwards. These assets provide relatively low-cost optionality, enabling REZ access in the Central-West region while the broader network architecture is being determined.

Across the non-seasonal best representations for both the Step Change and Green Energy Exports scenarios, investment trajectories are identical beginning with minimal early outlays ($0.28B in 2025–26), followed by a concentrated investment wave in 2030–31 totaling approximately $22.1B, predominantly driven by the commissioning of VNI West (SNSWWNV1, WNVMEL1) and Humelink (CNSWSNSW1) corridors, NNSWCNSW2 Hub upgrades, and key South Australian REZ expansions. This convergence suggests that under best-case development conditions, the optimal investment pathway is scenario-invariant for the near-to-medium term, with differentiation emerging primarily in the 2033–2046 period as scenario-specific demand and generation profiles begin to diverge.

The Progressive Change scenario produces a structurally similar trajectory under its non-seasonal best representation, but with somewhat lower total investment ($25.4B versus $38.6B for Step Change and Green Energy Exports best cases), reflecting a more measured pace of coal retirement and renewable deployment that moderates network stress and defers some augmentation requirements into the 2030s and beyond. The peak single-year expenditure under this pathway $11.8B in 2031 is the lowest of all non-seasonal best cases, indicating a more evenly distributed investment profile.

6.1.2 Non-seasonal versus seasonal planning pathways

A marked distinction emerges between optimal planning pathways derived from non-seasonal and seasonal modelling frameworks. Under non-seasonal representations, investment is typically more gradual and spread across a larger number of active build years, reflecting the treatment of each operating condition as independent and the optimization of network capability against a broad distribution of demand and supply states. The Step Change non-seasonal typical pathway, for example, involves investment activity across fifteen distinct years spanning 2025 to 2048, with multiple relatively modest expenditure peaks.

By contrast, seasonal representations, which co-optimize investment across temporally coupled operating conditions, accounting for the energy-limited behavior of storage and the correlated availability of renewable resources across days and seasons tend to produce more front-loaded and concentrated investment profiles. The Step Change and Progressive Change seasonal typical pathways commit approximately $32B and $62B respectively in the first two years (2025–2026), reflecting the model's recognition that adequacy risk under correlated seasonal stress conditions necessitates early and comprehensive network reinforcement. The seasonal worst representations across all three scenarios converge on a single concentrated build: approximately $61.6B of transmission infrastructure commissioned in 2025 alone, representing the near-complete NEM augmentation portfolio, followed by $2.5B in 2026.

This contrast between non-seasonal and seasonal pathways has significant implications for planning policy. The seasonal modelling framework captures adequacy risks that are not visible to non-seasonal analysis particularly the risk of extended supply shortfalls during prolonged low-renewable periods when storage systems are simultaneously depleted. The earlier and larger investments identified under seasonal frameworks may therefore reflect a more accurate representation of the infrastructure required to meet reliability standards under adverse but plausible system conditions.

Table 6.1 Optimal planning outcomes for different representations of 2024 ISP Step Change scenario

SCENARIO: STEP CHANGE						
Year	Non-Seasonal — Branch IDs			Seasonal — Branch IDs		
	Best	Typical	Worst	Best	Typical	Worst
2025	AC-3128	AC-3143, AC-3156, AC-3154, AC-3127, AC-3161, AC-3157, AC-3137, AC-3128, AC-3155	AC-3126, AC-3132, AC-3123, AC-3131, AC-3100, AC-3156, AC-3159, AC-3101, AC-3148, AC-3147, AC-3158, AC-3124, AC-3154, AC-3087, AC-3151, AC-3127, AC-3091, AC-3161, AC-3089, AC-3121, AC-3122, AC-3118, AC-3092, AC-3128, AC-3102, AC-3153, AC-3081, AC-3125, AC-3099, AC-3149, AC-3155, AC-3090, DC-10, DC-11, DC-9, DC-8	AC-3143, AC-3144, AC-3147, AC-3158, AC-3127, AC-3082, AC-3138, AC-3137, AC-3128	AC-3144, AC-3148, AC-3147, AC-3158, AC-3154, AC-3127, AC-3137, AC-3128, AC-3153, AC-3081, AC-3149	AC-3126, AC-3132, AC-3123, AC-3097, AC-3143, AC-3131, AC-3108, AC-3104, AC-3100, AC-3156, AC-3159, AC-3088, AC-3144, AC-3101, AC-3148, AC-3098, AC-3147, AC-3117, AC-3158, AC-3124, AC-3154, AC-3087, AC-3151, AC-3127, AC-3082, AC-3138, AC-3091, AC-3161, AC-3113, AC-3089, AC-3121, AC-3122, AC-3118, AC-3157, AC-3092, AC-3160, AC-3137, AC-3128, AC-3103, AC-3102, AC-3163, AC-3153, AC-3105, AC-3162, AC-3081, AC-3125, AC-3099, AC-3149, AC-3155, AC-3114, AC-3090
2026	AC-3127	—	AC-3157	AC-3100, AC-3091	AC-3132, AC-3143, AC-3122, AC-3131, AC-3121, AC-3157, AC-3156, AC-3124, AC-3151, AC-3082, AC-3138, AC-3113, AC-3155, AC-3114, DC-10, DC-11	DC-10, DC-11, DC-9, DC-8
2027	—	—	AC-3098, AC-3097, AC-3143, AC-3138, AC-3144, AC-3160, AC-3137	AC-3126, AC-3123, AC-3118, AC-3156, AC-3148, AC-3124, AC-3151	AC-3118, AC-3088, AC-3125, DC-9, DC-8	—
2028	—	AC-3126, AC-3121, AC-3160, AC-3138, AC-3125, DC-11, DC-9	AC-3082, AC-3088	AC-3132, AC-3131, AC-3153, DC-11	AC-3160, AC-3099	—
2029	—	AC-3122, AC-3158	—	AC-3121, AC-3122, AC-3087, AC-3113, AC-3114, DC-10	—	—
2030	AC-3156, AC-3144, AC-3117, AC-3158, AC-3154, AC-3138, AC-3118, AC-3157, AC-3137, AC-3149, AC-3155	DC-8	—	DC-9, DC-8	AC-3126, AC-3089, AC-3098, AC-3102, AC-3123, AC-3163, AC-3117, AC-3097, AC-3087, AC-3108, AC-3162, AC-3104, AC-3105, AC-3100, AC-3159, AC-3092, AC-3091, AC-3101, AC-3161, AC-3090, AC-3103	—
2031	AC-3132, AC-3143, AC-3131, AC-3121, DC-10, DC-11, DC-8	AC-3144, AC-3117, DC-10	—	—	—	—
2032	—	—	—	—	—	—
2033	AC-3123, AC-3124	—	—	AC-3102, AC-3099	—	—
2034	—	AC-3123, AC-3101	DC-6	AC-3089, AC-3097, AC-3108, AC-3104, AC-3157, AC-3088, AC-3159, AC-3092, AC-3101, AC-3160, AC-3103, AC-3098, AC-3163, AC-3117, AC-3154, AC-3105, AC-3162, AC-3081, AC-3125, AC-3161, AC-3149, AC-3155, AC-3090	—	—
2035	AC-3089, AC-3090	AC-3089, AC-3090	AC-3108, AC-3104, AC-3103, AC-3163, AC-3117, AC-3105, AC-3113, AC-3114, AC-3162	—	—	—
2036	DC-9	AC-3124	—	—	—	—
2037	AC-3101, AC-3102	AC-3092, AC-3098, AC-3102, AC-3091, DC-6	—	—	—	—
2038	AC-3091	—	—	—	—	—
2039	—	—	—	—	—	—
2040	AC-3092	—	—	—	—	—
2041	—	—	—	—	—	—
2042	AC-3097, AC-3098, AC-3087, AC-3082, AC-3081, DC-7	AC-3097	—	—	—	—
2043	—	AC-3132, AC-3131, AC-3149	—	—	—	—
2044	—	AC-3118	—	—	—	—
2045	AC-3100	—	—	—	—	—
2046	AC-3088, AC-3099	AC-3153, AC-3099	—	—	—	—
2047	—	AC-3087, AC-3100, AC-3088, AC-3082, AC-3081	—	—	—	—
2048	—	AC-3147, AC-3148	—	—	—	—
2049	—	—	—	—	—	—
2050	—	—	—	—	—	—
2051	—	—	—	—	—	—

Table 6.2 Optimal planning outcomes for different representations of 2024 ISP Progressive Change scenario

SCENARIO: PROGRESSIVE CHNAGE						
Year	Non-Seasonal — Branch IDs			Seasonal — Branch IDs		
	Best	Typical	Worst	Best	Typical	Worst
2025	AC-3128	AC-3156, AC-3144, AC-3154, AC-3127, AC-3161, AC-3157, AC-3137, AC-3128, AC-3155	AC-3126, AC-3132, AC-3123, AC-3131, AC-3104, AC-3100, AC-3156, AC-3117, AC-3158, AC-3124, AC-3154, AC-3127, AC-3161, AC-3089, AC-3121, AC-3122, AC-3118, AC-3157, AC-3160, AC-3128, AC-3153, AC-3105, AC-3162, AC-3125, AC-3099, AC-3155, AC-3090, DC-10, DC-11, DC-9, DC-8	AC-3144, AC-3148, AC-3147, AC-3158, AC-3151, AC-3127, AC-3138, AC-3128, AC-3153, AC-3081	AC-3143, AC-3148, AC-3147, AC-3158, AC-3127, AC-3082, AC-3138, AC-3128, AC-3153, AC-3155	AC-3126, AC-3132, AC-3123, AC-3097, AC-3143, AC-3131, AC-3108, AC-3104, AC-3100, AC-3156, AC-3159, AC-3088, AC-3144, AC-3101, AC-3148, AC-3098, AC-3147, AC-3117, AC-3158, AC-3124, AC-3154, AC-3087, AC-3151, AC-3127, AC-3082, AC-3138, AC-3091, AC-3161, AC-3113, AC-3089, AC-3121, AC-3122, AC-3118, AC-3157, AC-3092, AC-3160, AC-3137, AC-3128, AC-3103, AC-3102, AC-3163, AC-3153, AC-3105, AC-3162, AC-3081, AC-3125, AC-3099, AC-3149, AC-3155, AC-3114, AC-3090
2026	—	AC-3121, AC-3104, AC-3103, AC-3105, AC-3091	AC-3102	AC-3126, AC-3132, AC-3143, AC-3131, AC-3137, AC-3124, AC-3154, AC-3149, AC-3155	AC-3089, AC-3126, AC-3132, AC-3123, AC-3097, AC-3131, AC-3122, AC-3121, AC-3108, AC-3118, AC-3104, AC-3157, AC-3100, AC-3088, AC-3159, AC-3156, AC-3144, AC-3101, AC-3160, AC-3137, AC-3092, AC-3103, AC-3098, AC-3102, AC-3163, AC-3124, AC-3117, AC-3154, AC-3087, AC-3162, AC-3151, AC-3105, AC-3081, AC-3091, AC-3125, AC-3161, AC-3113, AC-3099, AC-3149, AC-3090, AC-3114	DC-10, DC-11, DC-9, DC-8
2027	AC-3127	—	AC-3144, AC-3101, AC-3148, AC-3137, AC-3147, AC-3138	AC-3121, AC-3122, AC-3117, AC-3113, DC-10	—	—
2028	—	AC-3158, AC-3138	AC-3143, AC-3082	DC-11	—	—
2029	—	AC-3123, AC-3124, AC-3113	—	AC-3123, AC-3157, AC-3156, AC-3125	—	—
2030	—	AC-3122, AC-3159, AC-3125, AC-3149, DC-11, DC-9, DC-8	DC-6, DC-7	—	DC-10, DC-9	—
2031	AC-3126, AC-3158, AC-3154, AC-3138, AC-3121, AC-3122, AC-3157, AC-3137, AC-3125, AC-3155, DC-10, DC-9	AC-3101, AC-3102	AC-3149	—	—	—
2032	—	—	—	AC-3089, AC-3097, AC-3108, AC-3118, AC-3104, AC-3100, AC-3088, AC-3159, AC-3092, AC-3101, AC-3160, AC-3103, AC-3098, AC-3102, AC-3163, AC-3087, AC-3105, AC-3162, AC-3082, AC-3091, AC-3161, AC-3099, AC-3090, AC-3114	DC-8	—
2033	AC-3123, AC-3156, AC-3102, AC-3124, DC-6, DC-11	—	AC-3081, AC-3091, AC-3103	—	—	—
2034	—	AC-3114, DC-10	—	—	—	—
2035	AC-3144	—	AC-3092	—	—	—
2036	AC-3091	AC-3126, AC-3143, AC-3147	—	—	—	—
2037	—	—	AC-3098, AC-3097, AC-3108	—	DC-11	—
2038	AC-3101	AC-3089	AC-3087	DC-9, DC-8	—	—
2039	AC-3090	AC-3082	—	—	—	—
2040	—	AC-3098, AC-3097, AC-3108, AC-3081, AC-3092, AC-3090	—	—	—	—
2041	—	—	—	—	—	—
2042	AC-3098, AC-3081	AC-3087, AC-3088, AC-3099, AC-3148	AC-3088	—	—	—
2043	—	AC-3100	—	—	—	—
2044	—	—	—	—	—	—
2045	AC-3143	—	—	—	—	—
2046	AC-3118, AC-3092, AC-3117, DC-8	—	—	—	—	—
2047	—	—	—	—	—	—
2048	—	—	AC-3151	—	—	—
2049	—	—	AC-3163, AC-3159, AC-3113, AC-3114	—	—	—
2050	—	—	—	—	—	—
2051	—	—	—	—	—	—

Table 6.3 Optimal planning outcomes for different representations of 2024 ISP Green Energy Exports scenario

SCENARIO: GREEN ENERGY EXPORTS						
Year	Non-Seasonal — Branch IDs			Seasonal — Branch IDs		
	Best	Typical	Worst	Best	Typical	Worst
2025	AC-3127, AC-3128	AC-3143, AC-3144, AC-3154, AC-3127, AC-3138, AC-3161, AC-3137, AC-3128, AC-3155	AC-3126, AC-3132, AC-3123, AC-3097, AC-3131, AC-3104, AC-3156, AC-3101, AC-3158, AC-3124, AC-3154, AC-3087, AC-3127, AC-3161, AC-3089, AC-3121, AC-3122, AC-3118, AC-3157, AC-3160, AC-3128, AC-3103, AC-3102, AC-3153, AC-3105, AC-3162, AC-3125, AC-3099, AC-3155, AC-3090, DC-10, DC-11, DC-9, DC-8	AC-3144, AC-3147, AC-3158, AC-3127, AC-3137, AC-3128	AC-3144, AC-3148, AC-3147, AC-3158, AC-3154, AC-3127, AC-3082, AC-3138, AC-3128, AC-3153, AC-3081	AC-3126, AC-3132, AC-3123, AC-3097, AC-3143, AC-3131, AC-3108, AC-3104, AC-3100, AC-3156, AC-3159, AC-3088, AC-3144, AC-3101, AC-3148, AC-3098, AC-3147, AC-3117, AC-3158, AC-3124, AC-3154, AC-3087, AC-3151, AC-3127, AC-3082, AC-3138, AC-3091, AC-3161, AC-3113, AC-3089, AC-3121, AC-3122, AC-3118, AC-3157, AC-3092, AC-3160, AC-3137, AC-3128, AC-3103, AC-3102, AC-3163, AC-3153, AC-3105, AC-3162, AC-3081, AC-3125, AC-3099, AC-3149, AC-3155, AC-3114, AC-3090
2026	—	—	AC-3151, AC-3100, AC-3149	AC-3143, AC-3156, AC-3138, AC-3153	AC-3126, AC-3132, AC-3123, AC-3143, AC-3122, AC-3131, AC-3121, AC-3137, AC-3124, AC-3117, AC-3151, AC-3113, AC-3149, AC-3114, DC-10, DC-11	DC-10, DC-11, DC-9, DC-8
2027	—	—	AC-3147, AC-3143, AC-3144, AC-3138, AC-3148, AC-3137	AC-3132, AC-3123, AC-3131, AC-3122, AC-3121, AC-3154, AC-3125, AC-3113, DC-10, DC-11	AC-3155, DC-9, DC-8	—
2028	—	AC-3132, AC-3131, AC-3122, AC-3121, AC-3157, AC-3156, AC-3101, AC-3160, AC-3158, AC-3117, AC-3162, DC-10, DC-6, DC-11, DC-8	AC-3082, AC-3092, AC-3081, AC-3091	AC-3151, AC-3081, AC-3114	AC-3088	—
2029	—	DC-9	AC-3098, AC-3088	AC-3148, AC-3117, DC-9, DC-8	AC-3102	—
2030	AC-3156, AC-3144, AC-3117, AC-3158, AC-3154, AC-3138, AC-3121, AC-3118, AC-3157, AC-3137, AC-3155	—	AC-3159	—	AC-3157	—
2031	AC-3132, AC-3123, AC-3143, AC-3131, DC-10, DC-11, DC-9	—	—	AC-3126, AC-3089, AC-3097, AC-3108, AC-3118, AC-3104, AC-3157, AC-3100, AC-3088, AC-3159, AC-3092, AC-3101, AC-3160, AC-3103, AC-3098, AC-3102, AC-3163, AC-3124, AC-3087, AC-3162, AC-3105, AC-3082, AC-3091, AC-3161, AC-3099, AC-3149, AC-3155, AC-3090	DC-6	—
2032	AC-3148, AC-3147, AC-3090	AC-3100, AC-3149	—	—	AC-3089, AC-3097, AC-3108, AC-3118, AC-3104, AC-3100, AC-3156, AC-3159, AC-3092, AC-3101, AC-3160, AC-3103, AC-3098, AC-3163, AC-3087, AC-3105, AC-3162, AC-3091, AC-3125, AC-3161, AC-3099, AC-3090	—
2033	AC-3089, AC-3098, AC-3124	AC-3089, AC-3123, AC-3124, AC-3090	—	—	—	—
2034	AC-3101, AC-3102	—	—	—	—	—
2035	AC-3122	—	—	—	—	—
2036	—	—	—	—	—	—
2037	—	AC-3102	—	—	—	—
2038	AC-3092	—	—	—	—	—
2039	—	—	—	—	—	—
2040	—	AC-3148, AC-3147	—	—	—	—
2041	—	—	—	—	—	—
2042	—	—	AC-3163, AC-3117, AC-3113, AC-3114, AC-3108	—	—	—
2043	—	—	—	—	—	—
2044	—	AC-3097, AC-3092, AC-3098, AC-3091	—	—	—	—
2045	AC-3091, DC-8	—	—	—	—	—
2046	AC-3097, DC-6	AC-3082, AC-3081	—	—	—	—
2047	—	AC-3087, AC-3088, AC-3099	—	—	—	—
2048	—	AC-3118	—	—	—	—
2049	—	AC-3151	—	—	—	—
2050	AC-3099	—	—	—	—	—
2051	—	—	—	—	—	—

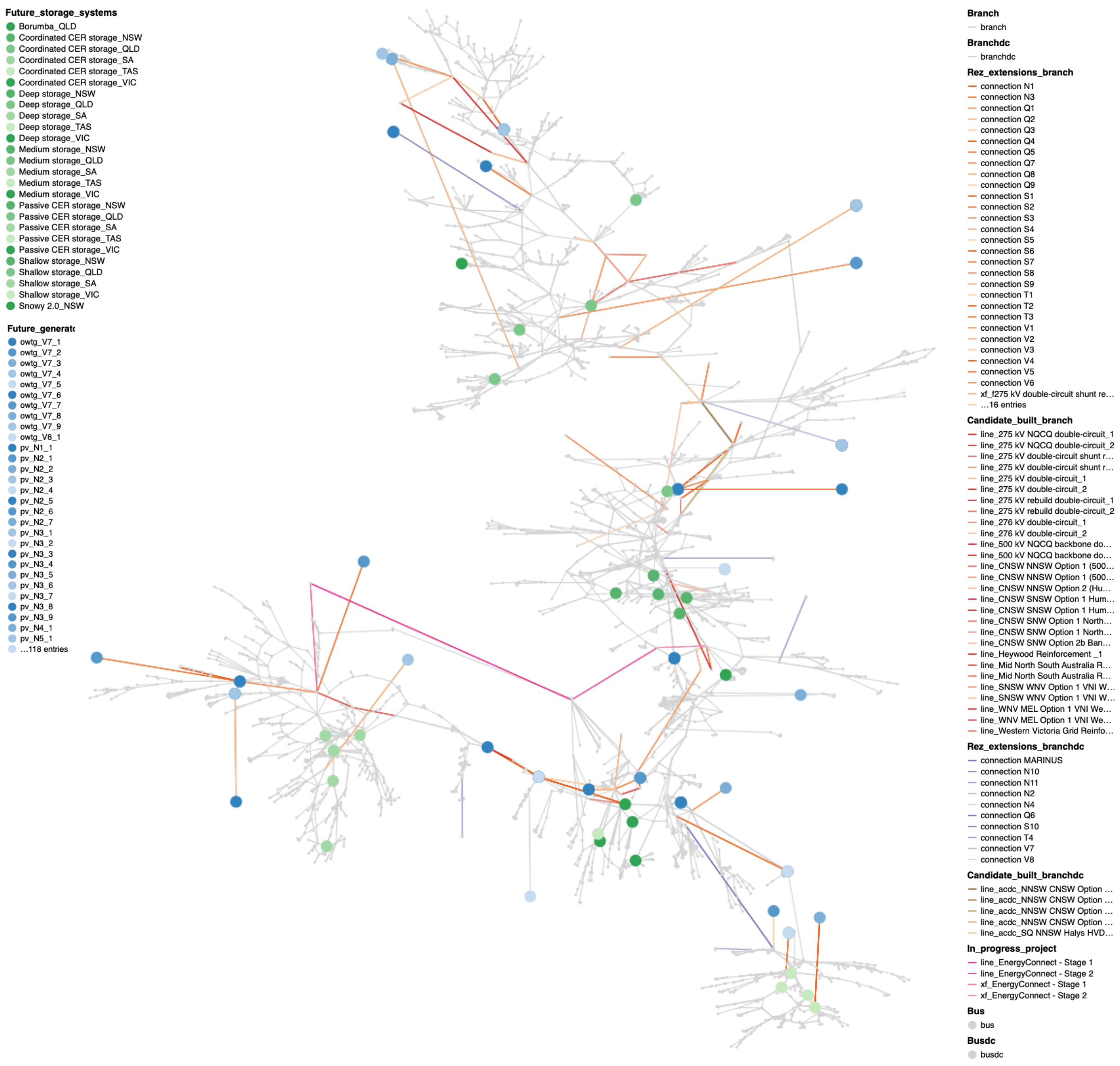


Figure 6.1 Graphical representation of optimal planning outcomes for 2024 ISP Step Change scenario non-seasonal best representations indicating the new network built on top of the existing SNEM power system

6.1.3 Scenario-Specific Pathway Characteristics

The Step Change scenario characterized by accelerated coal retirement and rapid renewable deployment produces the broadest range of optimal investment pathways across representations. The non-seasonal best case requires $38.6B in total investment by 2051, while the non-seasonal worst case reaches $65.2B, reflecting a $26.6B span that underscores the sensitivity of the optimal pathway to operating conditions. The non-seasonal typical pathway ($47.8B) involves investment spread across fifteen active build years, with the largest single-year expenditure of $7.5B occurring as late as 2043, indicating that under median conditions, some major augmentations can be deferred without compromising reliability.

The Progressive Change scenario, reflecting a more gradual transition, produces the lowest non-seasonal best-case investment requirement ($25.4B), but its non-seasonal worst case ($66.2B) is the highest of all three scenarios. This wide range signals that the progressive pathway carries higher tail risk under adverse conditions, deferred renewable deployment and extended thermal operation create network stress that requires extensive and costly remediation. The non-seasonal typical pathway ($49.4B) is broadly comparable to the Step Change equivalent, suggesting that at the median, the two scenarios impose similar infrastructure demands, but through different mechanisms and timing.

The Green Energy Exports scenario, which introduces substantial additional demand from hydrogen electrolysis and export-oriented renewable generation produces investment profiles that broadly align with the Step Change scenario under non-seasonal best and typical conditions, but with a somewhat lower worst-case total ($62.0B versus $65.2B). This counterintuitive result arises because the Green Energy Exports scenario's high renewable build supports both export demand and domestic adequacy, reducing marginal network stress even as total system scale increases. The Green Energy Exports seasonal typical pathway ($64.5B) is marginally higher than the equivalent Step Change and Progressive seasonal cases, reflecting the additional network capability required to support coordinated export and domestic supply across seasonal operating periods.

6.2 Economic Assessment of Planning Pathways

This section presents a structured comparison of cumulative transmission investment costs across all scenario-representation combinations, spanning the planning horizon from 2025 to 2051. All costs are reported in Australian dollars and represent the aggregated capital expenditure of new AC as well as DC transmission assets identified as optimal under each planning pathways.

6.2.1 Total cumulative investment by scenario and representation

The cumulative yearly investments for all three scenarios in seasonal and non-seasonal representations are shown in Figure 6.2. Furthermore, the total cumulative transmission investment by 2051 for all eighteen scenario-representation combinations are summarized in Table 6.4.

First, seasonal representations consistently produce higher total investment than their non-seasonal counterparts, except in the case of the worst representation under Step Change and Progressive scenarios, where the non-seasonal worst modestly exceeds the seasonal total. This reflects the fact that seasonal co-optimization identifies a more comprehensive set of network augmentations necessary to ensure adequacy across correlated operating conditions, while worst-case non-seasonal analysis independently stresses each period, potentially identifying a larger portfolio of individually triggered investments.

Table 6.4 Total Cumulative Transmission Investment by 2051 (A$B)

Representation	Non-seasonal			Seasonal		
	Step Change	Progressive Change	Green Energy Exports	Step Change	Progressive Change	Green Energy Exports
Best	$38.6B	$25.4B	$38.6B	$64.1B	$64.1B	$64.1B
Typical	$47.8B	$49.4B	$47.2B	$64.1B	$64.1B	$64.5B
Worst	$65.2B	$66.2B	$62.0B	$64.1B	$64.1B	$64.1B

Second, the spread between best and worst representations is significantly wider under non-seasonal frameworks (ranging from $26.6B for Step Change to $40.9B for Progressive Change) than under seasonal frameworks (where the spread is near-zero for Step Change and Progressive Change, with all seasonal representations converging to approximately $64.1B). This convergence of seasonal costs reflects the model finding that, regardless of the specific operating case used to derive the seasonal pathway, the full augmentation portfolio is required to maintain adequacy across all seasons the worst-case seasonal conditions effectively dictate the complete investment requirement.

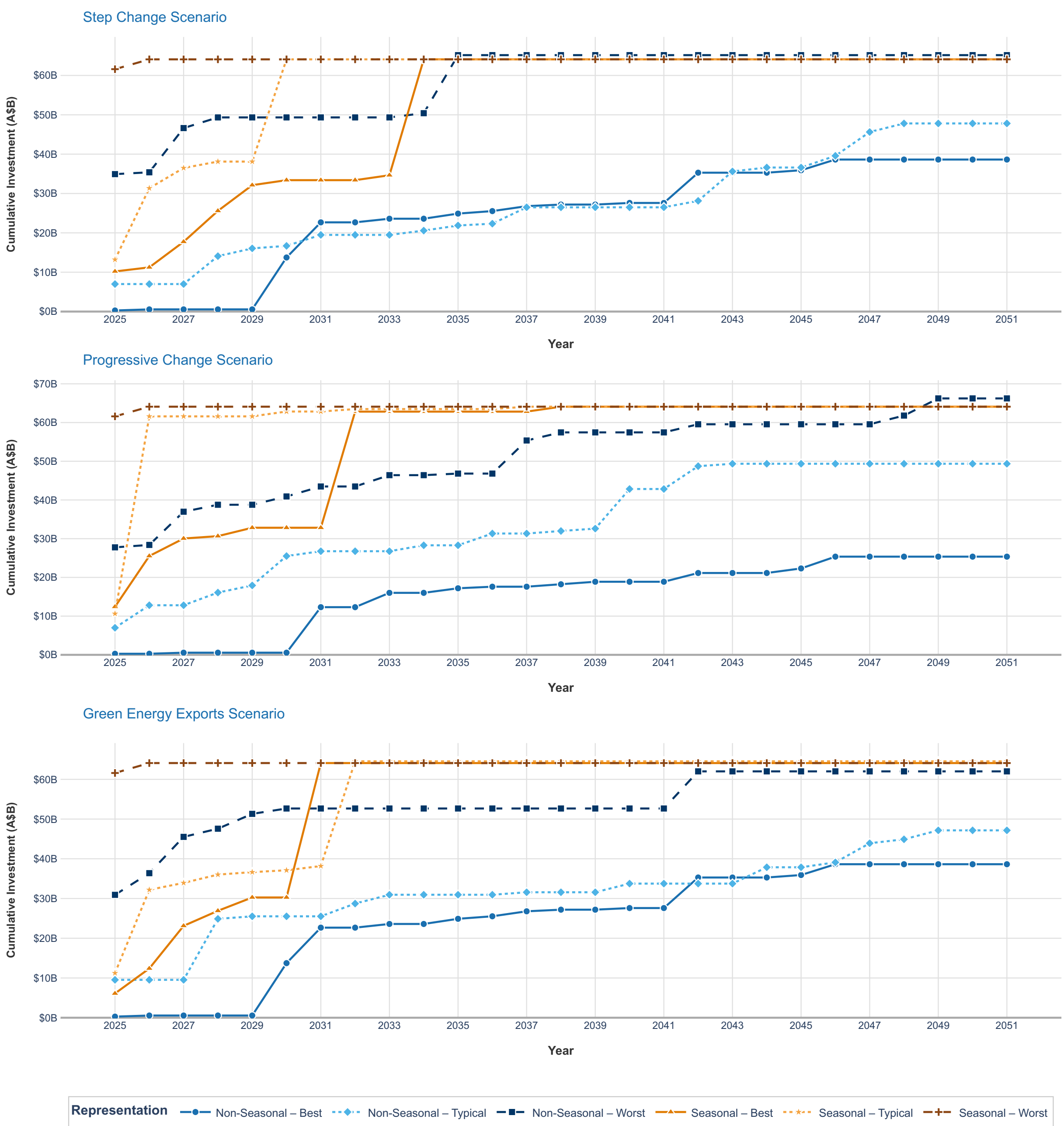


Figure 6.2 The yearly cumulative investment by scenario and representation

Third, the Progressive Change non-seasonal best case ($25.4B) is notably lower than equivalent Step Change and Green Energy Exports best cases (both $38.6B), consistent with the scenario's more gradual transition profile deferring or eliminating some augmentation requirements. However, this advantage disappears entirely under seasonal and worst-case representations, where the Progressive pathway converges to the same infrastructure requirement as the more aggressive transition scenarios.

6.2.2 Peak annual expenditure and investment timing

The peak single-year transmission capital expenditure and the year in which it occurs, for each scenario-representation combination is presented in Table 6.5. This metric captures the maximum financial commitment required in any single year and is a critical input to infrastructure financing and delivery planning.

Table 6.5 Peak Single-Year Transmission Investment and Year of Occurrence

Representation	Non-seasonal			Seasonal		
	Step Change	Progressive Change	Green Energy Exports	Step Change	Progressive Change	Green Energy Exports
Best	\$13.2B (2030)	\$11.8B (2031)	\$13.2B (2030)	\$29.5B (2034)	\$30.0B (2032)	\$33.8B (2031)
Typical	\$7.5B (2043)	\$10.2B (2040)	\$15.4B (2028)	\$26.0B (2030)	\$51.0B (2026)	\$26.4B (2032)
Worst	\$34.9B (2025)	\$27.8B (2025)	\$30.9B (2025)	\$61.6B (2025)	\$61.6B (2025)	\$61.6B (2025)

Note: Values represent the maximum annual capital expenditure within the planning period 2025–2051 and the year in which it occurs. Seasonal worst representations across all three scenarios share the same peak (\$61.6B in 2025), reflecting the full portfolio committed in a single year.

The peak expenditure data in Table 6.5 reveals a critical tension in transmission planning. Under non-seasonal best representations, investment is relatively modest in peak terms (\$11.8B–\$13.2B) and occurs in the late 2020s to early 2030s, broadly consistent with current project pipelines and financing capacity. Under non-seasonal worst representations, however, peak annual expenditure reaches \$27.8B–\$34.9B, occurring in 2025 itself. This implies that worst-case conditions require an immediate and massive commitment of capital that far exceeds the current rate of transmission investment in the NEM (approximately \$3–5B per year) and would place severe demands on the construction and supply chain ecosystem.

The seasonal representations are more extreme still. The seasonal step change pathways require high investments of around \$50B in years 2030 to 2034, while all seasonal worst cases demand \$61.6B in 2025, more than fifteen times the current annual transmission investment rate. These figures are not intended to be interpreted as literal planning targets, but rather as indicators of the scale of infrastructure commitment that would be required if the full spectrum of seasonal adequacy risk were to be managed entirely through network augmentation. In practice, complementary measures including demand response, additional dispatchable storage, and operational flexibility would be deployed alongside transmission investment to manage these risks at lower cost.

6.2.3 Cost range and planning uncertainty

Across all scenario-representation combinations, the plausible range of total transmission investment by 2051 spans from \$25.4B (Progressive Change, non-seasonal best) to \$66.2B (Progressive Change, non-seasonal worst). The central non-seasonal estimates aggregating typical representations across the three scenarios cluster in the \$47–50B range. Seasonal typical estimates converge at approximately \$64.1–64.5B.

This \$25B to \$66B range represents the investment uncertainty attributable solely to operating conditions and modelling framework, holding the set of candidate augmentations constant. It does not capture uncertainty in construction costs, project delivery, technology costs, or policy settings, all of which would widen the range further. The implication for planning is that investment decisions should be staged and adaptive: early commitments to low-cost, high-optionality assets (such as the Bannaby–Sydney West connectors and REZ enabling works) are robust across the full range of scenarios and representations, while decisions on major backbone infrastructure should be reviewed regularly as operating conditions and scenario trajectories become clearer.

The convergence of seasonal worst-case costs across all three scenarios ($64.1B) is a particularly important planning signal. It suggests that the total infrastructure requirement to manage the most adverse plausible seasonal adequacy conditions is effectively scenario-invariant, the NEM requires broadly the same transmission augmentation portfolio regardless of whether the transition follows a Step Change, Progressive, or Green Energy Exports trajectory, once seasonal correlated risk is fully accounted for. The key planning variables are therefore not the total investment required, but rather the optimal sequencing of that investment and the extent to which non-network measures can substitute for transmission augmentation in the near term.

6.2.4 Robust no-regret investments

Beyond the scenario-specific patterns described in Sections 6.2.1 to 6.2.3, the economic assessment also identifies a smaller set of transmission augmentations that are committed under every one of the eighteen scenario-representation combinations examined. These elements form the "no-regret" investment core: regardless of whether the future unfolds as a Step Change, Progressive Change, or Green Energy Exports trajectory, and regardless of whether the network is sized against a non-seasonal or seasonal operating-condition framework, the model consistently identifies the same lines as economically necessary. Table 6.6 lists these robust assets, mapped to their parent option identifiers, physical attributes, and per-circuit construction costs. Twenty AC branch circuits and four HVDC interconnector segments are common to all eighteen pathways, representing approximately A$23.6 billion of committed transmission investment that is invariant to scenario or modelling-framework assumptions.

The robust investment portfolio is dominated by three structural backbones. First, the VNI West corridor (SNSWWNV1 + WNVMEL1, totaling A$6.95B) appears in every pathway, confirming its role as the most economically justified inter-state augmentation across the entire planning envelope. Second, the South Australian Mid-North REZ expansion (SESACSA1 + SESACSA2, totaling A$1.86B) is committed in all cases and provides the export pathway from the Mid-North wind and solar resources into the central SA load center, complemented by the Heywood Reinforcement (WNASESA1, A$0.98B) that strengthens the SA–VIC interconnection. Third, the Queensland CQ-SQ-NNSW backbone (CQGG1, CQSQ1, CQSQ2, SQSQ1, NNSWCNSW3, totaling A$5.92B of robust circuits) underpins the southward export of CQ and SQ renewable resources under all demand and supply conditions.

The four HVDC segments common to all pathways correspond to the Bass Strait Marinus-class link (segments DC-8 and DC-9) and to a northern HVDC interconnector (segments DC-10 and DC-11). Their universal commitment reflects the structural value of HVDC corridors in moving large blocks of energy across the longest transfer paths in the NEM, where AC alternatives are either uneconomic or stability limited. Notably, the only asset that appears in all best-case scenarios from 2025 onwards, the Bannaby–Sydney West option 2b connector pair (CNSWSNW3 + CNSWSNW4, A$0.55B combined) is among the lowest-cost augmentations in the entire portfolio, demonstrating that low-cost optionality assets are robust early commitments that should not be deferred under any planning narrative.

Table 6.6 Transmission options committed under all scenario and representation combinations

Branch ID	Opt ID	Asset description	Region(s)	kV	Cost (A$M)
AC-3090	CQGG1	275 kV CQ–GG rebuild double-circuit (cct 2)	QLD	275	650.0
AC-3091	CQSQ1	275 kV CQ–SQ double-circuit + shunt (cct 1)	QLD	275	410.0
AC-3092	CQSQ1	275 kV CQ–SQ double-circuit + shunt (cct 2)	QLD	275	410.0
AC-3098	CQSQ2	275/500 kV CQ–SQ double-circuit + shunt (cct 2)	QLD	500	1,643.5
AC-3101	SQSQ1	275 kV SQ–SQ intra-region double-circuit (cct 1)	QLD	275	625.0
AC-3102	SQSQ1	275 kV SQ–SQ intra-region double-circuit (cct 2)	QLD	275	625.0
AC-3121	NNSWCNSW3	500 kV NNSW–NNSW Hub 5 + Bayswater (cct 1)	NSW	500	996.5
AC-3123	CNSWSNW1	500 kV CNSW–SNW Northern ring (cct 1)	NSW	500	463.0
AC-3124	CNSWSNW1	500 kV CNSW–SNW Northern ring (cct 2)	NSW	500	463.0
AC-3127	CNSWSNW3	330 kV Bannaby–Sydney West (option 2b, cct A)	NSW	330	276.5
AC-3128	CNSWSNW4	330 kV Bannaby–Sydney West (option 2b, cct B)	NSW	330	276.5
AC-3137	SNSWWNV1	500 kV SNSW–WNV VNI West (cct 1)	NSW/VIC	500	2,296.0
AC-3138	SNSWWNV1	500 kV SNSW–WNV VNI West (cct 2)	NSW/VIC	500	2,296.0
AC-3143	WNVMEL1	500 kV WNV–MEL VNI West (cct 1)	VIC	500	1,180.0
AC-3144	WNVMEL1	500 kV WNV–MEL VNI West (cct 2)	VIC	500	1,180.0
AC-3154	SESACSA1	275 kV Mid-North SA REZ expansion (cct 1)	SA	275	465.0
AC-3155	SESACSA1	275 kV Mid-North SA REZ expansion (cct 2)	SA	275	465.0
AC-3156	SESACSA2	275 kV Mid-North SA REZ expansion (cct 1)	SA	275	465.0
AC-3157	SESACSA2	275 kV Mid-North SA REZ expansion (cct 2)	SA	275	465.0
AC-3158	WNASESA1	275 kV Heywood Reinforcement	SA/VIC	275	980.0
DC-8	Marinus-A	HVDC Bass Strait link, segment A	TAS–VIC	±500	620.0
DC-9	Marinus-B	HVDC Bass Strait link, segment B	TAS–VIC	±500	620.0
DC-10	HVDC-N	HVDC inter-regional bipolar, segment 1	QLD–NSW	±500	620.0
DC-11	HVDC-N	HVDC inter-regional bipolar, segment 2	QLD–NSW	±500	620.0

Note: Per-circuit cost calculated as the relevant option capital cost divided by the number of circuits committed under that option. AC = HVAC overhead/underground line circuit; DC = HVDC bipolar segment.

Approximately A$23.6B of the A$25.4B–A$66.2B total-investment range identified in Section 6.2.3 is therefore committed under every plausible operating condition and scenario trajectory. This is roughly 36–93% of total cumulative investment, depending on scenario and representation. The implication for transmission regulators and infrastructure financiers is that approval and procurement of these no-regret elements can proceed independently of scenario adjudication: their economic justification is invariant to whether the NEM ultimately follows an accelerated, progressive, or export-led transition pathway, and they form a natural "first tranche" of regulated transmission investment commitments. The remaining variance between A$1.8B and A$42.6B is what the planning framework leaves to be resolved as scenario uncertainty.

6.3 Operational Assessment of Planning Pathways

While Sections 6.1 and 6.2 examined the optimal investment commitments and their cost implications, this section turns to the operational behavior of the NEM under each planning pathway. The transmission investments identified in the planning optimization are not ends in themselves; they exist to enable a specific dispatch outcome that meets demand reliably while minimizing operating costs. Understanding how generation is dispatched, where and when renewable curtailment occurs, and how storage assets are operated under each pathway is therefore essential to validating the planning recommendations. Figure 6.3 presents the annual aggregated power dispatch categorized by fuel type for all eighteen scenario-representations. The comparison structure permits a direct visual assessment of how the choice of modelling framework affects not only what is built (Section 6.1) but also how the resulting network is operated.

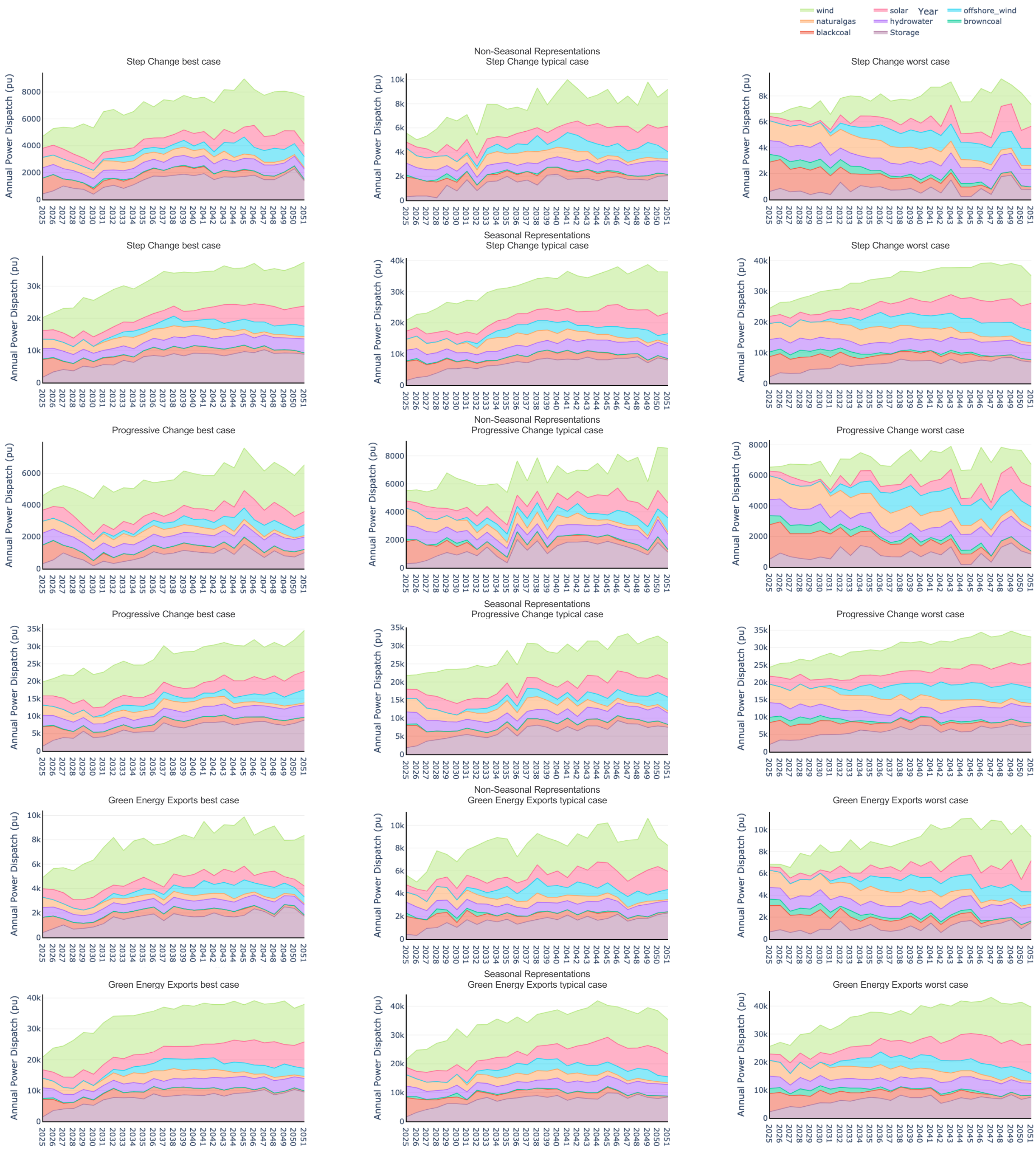


Figure 6.3 Aggregated annual power dispatch across all representations categorized by fuel type

6.3.1 Non-seasonal dispatch behavior

The non-seasonal dispatch outcomes (top three panels for each scenario in Figure 6.3) treat each operating condition as a thermally and energetically independent state, with sufficient short-duration storage available within each snapshot to balance instantaneous variability. Under this representation, all three scenarios, Step Change, Progressive Change, and Green Energy Exports, converge on a qualitatively similar dispatch pattern by the late 2030s: black coal generation exits the merit order during the 2028–2032 retirement wave, gas generation occupies a residual peaking role of approximately 2–8 TWh per year, and wind, utility-scale solar PV, and roof-top PV jointly supply 75–85 % of annual energy from the early 2030s onwards.

Within this broadly common end-state, three behavioral distinctions are evident across the non-seasonal best, typical, and worst cases. First, the best-case representations exhibit the lowest annual unserved-energy and curtailment footprints, because the planner has selected an investment portfolio matched to favorable generation availability and load conditions; in these dispatch patterns, renewable curtailment averages only 2–4 % of available wind/solar energy. Second, the typical-case dispatch shows curtailment rising to 5–8 % and a more pronounced gas peaking signature in the 2030–2035 transitional period as thermal capacity is being retired but transmission augmentations are still ramping in. Third, the worst-case dispatch, built on a near-complete network augmentation portfolio, eliminates almost all transmission-driven curtailment but exhibits noticeable structural over-build, with renewable capacity factors depressed by 3–6 percentage points relative to the best case as supply exceeds the binding demand on a larger fraction of operating hours.

The Step Change scenario produces the most rapid post-2030 growth in renewable dispatch share, reflecting both the accelerated coal retirement schedule and the associated network commitments described in Section 6.1. By 2040, wind energy alone supplies 35–42 % of annual NEM energy under all three Step Change non-seasonal representations. The Progressive Change scenario displays a more gradual energy-mix transition, with black coal generation persisting at 5–12 TWh/yr into the mid-2030s under non-seasonal best and typical representations, a feature that is operationally less stressful for the network but extends the scenario's exposure to coal-fleet reliability risk. The Green Energy Exports non-seasonal dispatch introduces a step-change in total energy demand from approximately 2032 onwards as hydrogen electrolysis loads come online; in the dispatch panels this appears as an upward shift of 30–60 TWh/yr in total wind and utility-solar generation, absorbed primarily by the additional REZ and inter-regional capacity committed under the Green Energy Exports pathway.

6.3.2 Seasonal dispatch behavior

The seasonal dispatch panels (bottom three for each scenario) reveal a qualitatively different operational picture. Because the seasonal framework co-optimizes investment and dispatch across temporally coupled operating windows, the resulting network is sized to meet adequacy across correlated low-renewable and high-demand sequences, and the dispatch patterns reflect this richer constraint set.

The most striking feature of the seasonal dispatch panels is the reduced year-to-year volatility of gas generation relative to the matched non-seasonal panels. Under non-seasonal representations, gas dispatch can spike to 10–14 TWh/yr in transitional years (2028–2031) before falling back to 2–3 TWh/yr; under seasonal representations the same scenario typically shows a smoother gas profile of 4–7 TWh/yr sustained into the late 2030s, because the seasonal framework has committed sufficient transmission and storage capability to displace the within-season gas peaking that the non-seasonal model required. The seasonal worst-case panels corresponding to the A$61.6B-in-2025 portfolios noted in Section 6.2 exhibit the lowest residual gas and the highest renewable dispatch shares of any of the eighteen panels, often exceeding 90 % renewable energy share by 2035.

Storage operation also differs materially between the two frameworks. The non-seasonal panels show storage charging and discharging in support of intra-day arbitrage and short-term reserves, visible as a roughly flat net storage contribution over the year. The seasonal panels, by contrast, exhibit a clear seasonal cycling signature, with storage net-output positive in the low-renewable winter months (May–August in southern regions) and net-input positive in the spring and autumn shoulder periods. This seasonal storage cycling is enabled by the larger transmission capacity committed under the seasonal framework, which permits inter-regional energy transport to feed geographically remote storage assets during their charging windows.

Step Change seasonal dispatch shows the most aggressive renewable transition: by 2032, the seasonal best representation has effectively eliminated coal generation and reduced gas generation to under 2 TWh/yr, with wind and solar jointly supplying over 88 % of annual energy. The Progressive Change seasonal panels show a more sustained role for gas peaking, averaging 5–8 TWh/yr through to 2040, consistent with the slower coal retirement pathway. The Green Energy Exports seasonal dispatch, in addition to the post-2032 hydrogen-load uplift visible in the non-seasonal panels, shows a distinctive seasonal pattern in hydrogen production itself: electrolysis loads scale with renewable availability, concentrating in the spring and summer months and dropping by 25–40 % during the seasonal trough. This behavior, which is invisible to the non-seasonal framework, has direct implications for downstream hydrogen storage and export infrastructure sizing.

6.3.3 Comparative implications

Three operational findings emerge consistently from the dispatch comparisons in Figure 6.3. First, the seasonal framework systematically reports lower residual gas dispatch and higher renewable utilization than the matched non-seasonal framework; the additional transmission and storage capability committed under the seasonal pathway is therefore recoverable in operational savings, partially offsetting the higher capital cost identified in Section 6.2. Second, the dispatch patterns confirm that the worst-case representations are not operationally stressed despite their higher capital cost: the additional infrastructure provides operating flexibility rather than absorbing systemic stress. Third, the Green Energy Exports specific dispatch differences from Step Change emerge primarily through the magnitude of total energy and the seasonal modulation of electrolysis load, rather than through a structurally different fuel mix; for transmission-planning purposes, the Green Energy Exports and Step Change scenarios are best treated as graded variants of an accelerated-transition family rather than as qualitatively distinct futures.

These operational findings reinforce the planning conclusions drawn from the investment analysis. The seasonal framework's higher capital commitments are demonstrably delivering cleaner, more reliable, and lower-curtailment dispatch outcomes; conversely, the apparent capital efficiency of the non-seasonal best cases comes with measurable operational compromises in transitional periods. A robust planning recommendation must consider both dimensions, and the analysis in this section provides the empirical basis for doing so.

6.4 Security-Constraints Assessment in Planning Pathways

The investment pathways in Sections 6.1 to 6.3 were derived under a steady-state system operation power flow representation in which the network must satisfy the pre-contingency (N-0) limits and constraints across all selected operating conditions. This representation, while computationally tractable for a planning horizon of 27 years and 18 distinct scenario-representation combinations, omits a fundamental requirement of grid operations: the system must remain secure following the critical-contingency loss of a major transmission element or generator.

This section presents a security-constrained re-evaluation of the three non-seasonal best-case pathways (Step Change, Progressive Change, and Green Energy Exports) in which the optimization now enforces N-1 thermal feasibility for the set of critical contingencies identified in Chapter 4. The objective is twofold: first, to quantify the additional transmission investment required to secure the best-case planning pathways against credible single-element outages; and second, to expose the structural changes that the security overlay imposes on the optimal sequence and composition of network augmentations. The results presented here therefore complement, rather than replace, the N-0 results in Sections 6.1 to 6.3 as they bound the most likely upper envelope of regulated transmission expenditure once full security obligations are enforced.

6.4.1 Critical contingencies and methodology

The contingency set used in this assessment was determined in Chapter 4 from a screening of all inter-regional transmission-element single failures across the existing NEM network and the candidate augmentation portfolio. The screening procedure ranked contingencies by the magnitude of post-fault unserved energy across the remaining transmission corridors and retained those for which (i) the maximum post-fault overload exceeded 100 % of any branch's rated capacity in any operating condition, or (ii) the loss of the element disconnected a generator or REZ exceeding the capacity of the biggest REZ or generator in that region (area). The retained set defines the critical-contingency list against which the security-constrained optimization enforces N-1 feasibility in this section.

The optimization is otherwise identical to that described in Sections 6.1 to 6.3, as the same candidate-augmentation set, the same scenario demand and generation profiles, the same non-seasonal best-case operating-condition statistics. The only material difference is that, for each operating condition and each critical contingency in the retained set, the post-fault power flow must be feasible within thermal limits, as the planner cannot rely on post-fault manual re-dispatch or operational control schemes to clear post-contingency overloads.

The security-constrained pathway results for the three scenarios are presented in Tables 6.7 to 6.9 below, in the same format as the detailed branch schedules of Section 6.1 (and the Branch Costs by Scenario report). Each table lists the AC and DC branches commissioned in each year, with their individual cost and the running cumulative cost. The pre-security (N-0) baseline costs for the same pathway are tabulated in Tables 6.1 to 6.3 for support direct comparison, and the yearly-cost evolution is illustrated in Figure 6.4.

6.4.2 Detailed branch schedules with critical contingencies

Tables 6.4.1, 6.4.2, and 6.4.3 below list the security-constrained branch build schedules for the Step Change, Progressive Change, and Green Energy Exports best-case non-seasonal pathways respectively. Each row identifies a branch (AC or DC) commissioned in the listed year, its individual capital cost, the year subtotal, and the running cumulative cost in A$billions.

Table 6.7 Step Change scenario best representation (Non-Seasonal) with N-1 critical contingencies

Year	Branch ID	Branch description	Cost	Year subtotal	Cum. cost
2025	AC-3128	CNSWSNW4 – Bannaby–SydW (option 2b)	$276.5M	$276.5M	$0.28B
2026	AC-3123	CNSWSNW1 #1 – Northern 500 kV ring	$463.0M	$5,454.5M	$5.73B
	AC-3143	WNVMEL1 #1 – VNI West	$1,180.0M		
	AC-3127	CNSWSNW3 – Bannaby–SydW (option 2b)	$276.5M		
	AC-3082	NQCQ1 #2 – 275 kV NQ-CQ d-cct	$619.5M		
	AC-3137	SNSWWNV1 #1 – VNI West	$2,296.0M		
	AC-3081	NQCQ1 #1 – 275 kV NQ-CQ d-cct	$619.5M		
2031	AC-3132	CNSWSNSW1 #2 – Humelink	$2,446.0M	$15,568.0M	$21.30B
	AC-3131	CNSWSNSW1 #1 – Humelink	$2,446.0M		
	AC-3148	MELSEVIW1 #2 – Western Renewables Link	$1,090.0M		
	AC-3147	MELSEVIW1 #1 – Western Renewables Link	$1,090.0M		
	AC-3158	WNASESA1 – Heywood reinforcement	$980.0M		
	AC-3151	MELWNV2 – Western VIC reinforcement	$2,250.0M		
	AC-3138	SNSWWNV1 #2 – VNI West	$2,296.0M		
	AC-3153	MELWNV3 – Western VIC reinforcement	$2,350.0M		
	DC-10	HVDC link, segment 10 (northern pole 1)	$620.0M		
2032	AC-3124	CNSWSNW1 #2 – Northern 500 kV ring	$463.0M	$463.0M	$21.76B
2033	AC-3157	SESACSA2 #2 – Mid-North SA REZ	$465.0M	$5,977.0M	$27.74B
	AC-3156	SESACSA2 #1 – Mid-North SA REZ	$465.0M		
	AC-3154	SESACSA1 #1 – Mid-North SA REZ	$465.0M		
	AC-3113	NNSWCNSW1 #1 – Hub 1 upgrade	$917.0M		
	AC-3149	MELWNV1 – Western VIC reinforcement	$2,580.0M		
	AC-3155	SESACSA1 #2 – Mid-North SA REZ	$465.0M		
	DC-11	HVDC link, segment 11 (northern pole 2)	$620.0M		
2034	AC-3097	CQSQ2 #1 – 275/500 kV CQ-SQ d-cct	$1,643.5M	$7,280.0M	$35.02B
	AC-3121	NNSWCNSW3 #1 – Hub 5 + Bayswater	$996.5M		
	AC-3122	NNSWCNSW3 #2 – Hub 5 + Bayswater	$996.5M		
	AC-3092	CQSQ1 #2 – 275 kV CQ-SQ d-cct	$410.0M		
	AC-3144	WNVMEL1 #2 – VNI West	$1,180.0M		
	AC-3098	CQSQ2 #2 – 275/500 kV CQ-SQ d-cct	$1,643.5M		
	AC-3091	CQSQ1 #1 – 275 kV CQ-SQ d-cct	$410.0M		
2035	AC-3117	NNSWCNSW2 #1 – Hub 1 upgrade	$997.5M	$4,984.5M	$40.00B
	AC-3087	NQCQ2 #1 – 500 kV NQ-CQ backbone	$2,092.0M		
	AC-3099	CQCQ1 #1 – 275 kV intra-CQ d-cct	$625.0M		
	AC-3090	CQGG1 #2 – 275 kV CQ-GG rebuild	$650.0M		
	DC-9	HVDC link, segment 9 (Marinus-B)	$620.0M		
2036	AC-3126	CNSWSNW2 #2 – Southern 500 kV loop	$775.0M	$3,517.0M	$43.52B
	AC-3089	CQGG1 #1 – 275 kV CQ-GG rebuild	$650.0M		
	AC-3088	NQCQ2 #2 – 500 kV NQ-CQ backbone	$2,092.0M		
2037	AC-3102	SQSQ1 #2 – 275 kV intra-SQ d-cct	$625.0M	$19,935.5M	$63.46B
	AC-3163	TAS5 – Waddamana–Palmerston upgrade	$1,250.0M		
	AC-3108	SQNNSW3 – 500 kV NNSW backbone	$5,260.0M		
	AC-3118	NNSWCNSW2 #2 – Hub 1 upgrade	$997.5M		
	AC-3104	SQNNSW2 #1 – QNI 330 kV d-cct	$1,259.0M		
	AC-3105	SQNNSW2 #2 – QNI 330 kV d-cct	$1,259.0M		
	AC-3100	CQCQ1 #2 – 275 kV intra-CQ d-cct	$625.0M		
	AC-3162	TAS4 – Waddamana–Palmerston upgrade	$1,000.0M		
	AC-3159	TAS1 – Waddamana–Palmerston upgrade	$1,350.0M		
	AC-3125	CNSWSNW2 #1 – Southern 500 kV loop	$775.0M		
	AC-3101	SQSQ1 #1 – 275 kV intra-SQ d-cct	$625.0M		
	AC-3160	TAS2 – Waddamana–Palmerston upgrade	$1,000.0M		
	AC-3161	TAS3 – Waddamana–Palmerston upgrade	$1,100.0M		
	AC-3103	SQNNSW1 – QNI 330 kV s-cct	$1,893.0M		
	AC-3114	NNSWCNSW1 #2 – Hub 1 upgrade	$917.0M		
2041	DC-8	HVDC link, segment 8 (Marinus-A)	$620.0M	$620.0M	$64.08B

Table 6.8 Progressive Change scenario best representation (Non-Seasonal) with N-1 critical contingencies

Year	Branch ID	Branch description	Cost	Year subtotal	Cum. cost
2025	AC-3128	CNSWSNW4 – Bannaby–SydW (option 2b)	$276.5M	$276.5M	$0.28B
2026	AC-3143	WNVMEL1 #1 – VNI West	$1,180.0M	$9,478.5M	$9.76B
	AC-3144	WNVMEL1 #2 – VNI West	$1,180.0M		
	AC-3151	MELWNV2 – Western VIC reinforcement	$2,250.0M		
	AC-3127	CNSWSNW3 – Bannaby–SydW (option 2b)	$276.5M		
	AC-3138	SNSWWNV1 #2 – VNI West	$2,296.0M		
	AC-3137	SNSWWNV1 #1 – VNI West	$2,296.0M		
2030	AC-3148	MELSEVIW1 #2 – Western Renewables Link	$1,090.0M	$4,931.5M	$14.69B
	AC-3147	MELSEVIW1 #1 – Western Renewables Link	$1,090.0M		
	AC-3158	WNASESA1 – Heywood reinforcement	$980.0M		
	AC-3121	NNSWCNSW3 #1 – Hub 5 + Bayswater	$996.5M		
	AC-3125	CNSWSNW2 #1 – Southern 500 kV loop	$775.0M		
2031	AC-3131	CNSWSNSW1 #1 – Humelink	$2,446.0M	$7,405.5M	$22.09B
	AC-3117	NNSWCNSW2 #1 – Hub 1 upgrade	$997.5M		
	AC-3149	MELWNV1 – Western VIC reinforcement	$2,580.0M		
	AC-3155	SESACSA1 #2 – Mid-North SA REZ	$465.0M		
	AC-3114	NNSWCNSW1 #2 – Hub 1 upgrade	$917.0M		
2032	AC-3153	MELWNV3 – Western VIC reinforcement	$2,350.0M	$4,055.0M	$26.15B
	AC-3154	SESACSA1 #1 – Mid-North SA REZ	$465.0M		
	DC-10	HVDC link, segment 10 (northern pole 1)	$620.0M		
	DC-11	HVDC link, segment 11 (northern pole 2)	$620.0M		
2033	AC-3122	NNSWCNSW3 #2 – Hub 5 + Bayswater	$996.5M	$3,699.0M	$29.85B
	AC-3118	NNSWCNSW2 #2 – Hub 1 upgrade	$997.5M		
	AC-3156	SESACSA2 #1 – Mid-North SA REZ	$465.0M		
	DC-9	HVDC link, segment 9 (Marinus-B)	$620.0M		
	DC-8	HVDC link, segment 8 (Marinus-A)	$620.0M		
2035	AC-3132	CNSWSNSW1 #2 – Humelink	$2,446.0M	$3,528.5M	$33.37B
	AC-3124	CNSWSNW1 #2 – Northern 500 kV ring	$463.0M		
	AC-3081	NQCQ1 #1 – 275 kV NQ-CQ d-cct	$619.5M		
2038	AC-3123	CNSWSNW1 #1 – Northern 500 kV ring	$463.0M	$5,100.5M	$38.48B
	AC-3157	SESACSA2 #2 – Mid-North SA REZ	$465.0M		
	AC-3092	CQSQ1 #2 – 275 kV CQ-SQ d-cct	$410.0M		
	AC-3101	SQSQ1 #1 – 275 kV intra-SQ d-cct	$625.0M		
	AC-3103	SQNNSW1 – QNI 330 kV s-cct	$1,893.0M		
	AC-3102	SQSQ1 #2 – 275 kV intra-SQ d-cct	$625.0M		
	AC-3082	NQCQ1 #2 – 275 kV NQ-CQ d-cct	$619.5M		
2039	AC-3126	CNSWSNW2 #2 – Southern 500 kV loop	$775.0M	$2,075.0M	$40.55B
	AC-3089	CQGG1 #1 – 275 kV CQ-GG rebuild	$650.0M		
	AC-3090	CQGG1 #2 – 275 kV CQ-GG rebuild	$650.0M		
2040	AC-3105	SQNNSW2 #2 – QNI 330 kV d-cct	$1,259.0M	$1,259.0M	$41.81B
2042	AC-3104	SQNNSW2 #1 – QNI 330 kV d-cct	$1,259.0M	$4,386.0M	$46.20B
	AC-3088	NQCQ2 #2 – 500 kV NQ-CQ backbone	$2,092.0M		
	AC-3091	CQSQ1 #1 – 275 kV CQ-SQ d-cct	$410.0M		
	AC-3099	CQCQ1 #1 – 275 kV intra-CQ d-cct	$625.0M		
2044	AC-3098	CQSQ2 #2 – 275/500 kV CQ-SQ d-cct	$1,643.5M	$3,287.0M	$49.48B
	AC-3097	CQSQ2 #1 – 275/500 kV CQ-SQ d-cct	$1,643.5M		
2045	AC-3162	TAS4 – Waddamana–Palmerston upgrade	$1,000.0M	$14,594.0M	$64.08B
	AC-3163	TAS5 – Waddamana–Palmerston upgrade	$1,250.0M		
	AC-3100	CQCQ1 #2 – 275 kV intra-CQ d-cct	$625.0M		
	AC-3159	TAS1 – Waddamana–Palmerston upgrade	$1,350.0M		
	AC-3113	NNSWCNSW1 #1 – Hub 1 upgrade	$917.0M		
	AC-3160	TAS2 – Waddamana–Palmerston upgrade	$1,000.0M		
	AC-3161	TAS3 – Waddamana–Palmerston upgrade	$1,100.0M		
	AC-3087	NQCQ2 #1 – 500 kV NQ-CQ backbone	$2,092.0M		
	AC-3108	SQNNSW3 – 500 kV NNSW backbone	$5,260.0M		

Table 6.9 Green Energy Exports scenario best representation (Non-Seasonal) with N-1 critical contingencies

Year	Branch ID	Branch description	Cost	Year subtotal	Cum. cost
2025	AC-3128	CNSWSNW4 – Bannaby–SydW (option 2b)	$276.5M	$276.5M	$0.28B
2026	AC-3143	WNVMEL1 #1 – VNI West	$1,180.0M	$11,657.5M	$11.93B
	AC-3144	WNVMEL1 #2 – VNI West	$1,180.0M		
	AC-3124	CNSWSNW1 #2 – Northern 500 kV ring	$463.0M		
	AC-3127	CNSWSNW3 – Bannaby–SydW (option 2b)	$276.5M		
	AC-3082	NQCQ1 #2 – 275 kV NQ-CQ d-cct	$619.5M		
	AC-3138	SNSWWNV1 #2 – VNI West	$2,296.0M		
	AC-3121	NNSWCNSW3 #1 – Hub 5 + Bayswater	$996.5M		
	AC-3137	SNSWWNV1 #1 – VNI West	$2,296.0M		
	AC-3153	MELWNV3 – Western VIC reinforcement	$2,350.0M		
2030	AC-3132	CNSWSNSW1 #2 – Humelink	$2,446.0M	$12,149.0M	$24.08B
	AC-3131	CNSWSNSW1 #1 – Humelink	$2,446.0M		
	AC-3148	MELSEVIW1 #2 – Western Renewables Link	$1,090.0M		
	AC-3158	WNASESA1 – Heywood reinforcement	$980.0M		
	AC-3147	MELSEVIW1 #1 – Western Renewables Link	$1,090.0M		
	AC-3154	SESACSA1 #1 – Mid-North SA REZ	$465.0M		
	AC-3151	MELWNV2 – Western VIC reinforcement	$2,250.0M		
	AC-3113	NNSWCNSW1 #1 – Hub 1 upgrade	$917.0M		
	AC-3155	SESACSA1 #2 – Mid-North SA REZ	$465.0M		
2031	AC-3118	NNSWCNSW2 #2 – Hub 1 upgrade	$997.5M	$2,702.5M	$26.79B
	AC-3157	SESACSA2 #2 – Mid-North SA REZ	$465.0M		
	DC-10	HVDC link, segment 10 (northern pole 1)	$620.0M		
	DC-11	HVDC link, segment 11 (northern pole 2)	$620.0M		
2032	DC-9	HVDC link, segment 9 (Marinus-B)	$620.0M	$1,240.0M	$28.03B
	DC-8	HVDC link, segment 8 (Marinus-A)	$620.0M		
2033	AC-3126	CNSWSNW2 #2 – Southern 500 kV loop	$775.0M	$36,050.5M	$64.08B
	AC-3089	CQGG1 #1 – 275 kV CQ-GG rebuild	$650.0M		
	AC-3123	CNSWSNW1 #1 – Northern 500 kV ring	$463.0M		
	AC-3097	CQSQ2 #1 – 275/500 kV CQ-SQ d-cct	$1,643.5M		
	AC-3122	NNSWCNSW3 #2 – Hub 5 + Bayswater	$996.5M		
	AC-3108	SQNNSW3 – 500 kV NNSW backbone	$5,260.0M		
	AC-3104	SQNNSW2 #1 – QNI 330 kV d-cct	$1,259.0M		
	AC-3100	CQCQ1 #2 – 275 kV intra-CQ d-cct	$625.0M		
	AC-3156	SESACSA2 #1 – Mid-North SA REZ	$465.0M		
	AC-3159	TAS1 – Waddamana–Palmerston upgrade	$1,350.0M		
	AC-3092	CQSQ1 #2 – 275 kV CQ-SQ d-cct	$410.0M		
	AC-3088	NQCQ2 #2 – 500 kV NQ-CQ backbone	$2,092.0M		
	AC-3101	SQSQ1 #1 – 275 kV intra-SQ d-cct	$625.0M		
	AC-3160	TAS2 – Waddamana–Palmerston upgrade	$1,000.0M		
	AC-3103	SQNNSW1 – QNI 330 kV s-cct	$1,893.0M		
	AC-3098	CQSQ2 #2 – 275/500 kV CQ-SQ d-cct	$1,643.5M		
	AC-3102	SQSQ1 #2 – 275 kV intra-SQ d-cct	$625.0M		
	AC-3163	TAS5 – Waddamana–Palmerston upgrade	$1,250.0M		
	AC-3117	NNSWCNSW2 #1 – Hub 1 upgrade	$997.5M		
	AC-3087	NQCQ2 #1 – 500 kV NQ-CQ backbone	$2,092.0M		
	AC-3162	TAS4 – Waddamana–Palmerston upgrade	$1,000.0M		
	AC-3105	SQNNSW2 #2 – QNI 330 kV d-cct	$1,259.0M		
	AC-3081	NQCQ1 #1 – 275 kV NQ-CQ d-cct	$619.5M		
	AC-3091	CQSQ1 #1 – 275 kV CQ-SQ d-cct	$410.0M		
	AC-3125	CNSWSNW2 #1 – Southern 500 kV loop	$775.0M		
	AC-3161	TAS3 – Waddamana–Palmerston upgrade	$1,100.0M		
	AC-3099	CQCQ1 #1 – 275 kV intra-CQ d-cct	$625.0M		
	AC-3149	MELWNV1 – Western VIC reinforcement	$2,580.0M		
	AC-3090	CQGG1 #2 – 275 kV CQ-GG rebuild	$650.0M		
	AC-3114	NNSWCNSW1 #2 – Hub 1 upgrade	$917.0M		

Table 6.10 Total Cumulative Investment by 2051: With vs Without N-1 Contingencies

Scenario — representation	Without N-1	With N-1	Δ Investment	Δ %
Step Change — Best	$38.16B	$64.08B	+$25.91B	+68%
Progressive Change — Best	$24.89B	$64.08B	+$39.18B	+157%
Green Energy Exports — Best	$32.71B	$64.08B	+$31.36B	+96%

6.4.3 Cost comparison with vs without critical contingencies

Table 6.10 summarizes the impact of enforcing N-1 critical-contingency feasibility on the three best-case non-seasonal pathways. The security overlay uniformly drives total investment to approximately A$64.1B, the same envelope that the seasonal framework identified for adverse correlated operating conditions in Sections 6.1 and 6.2.

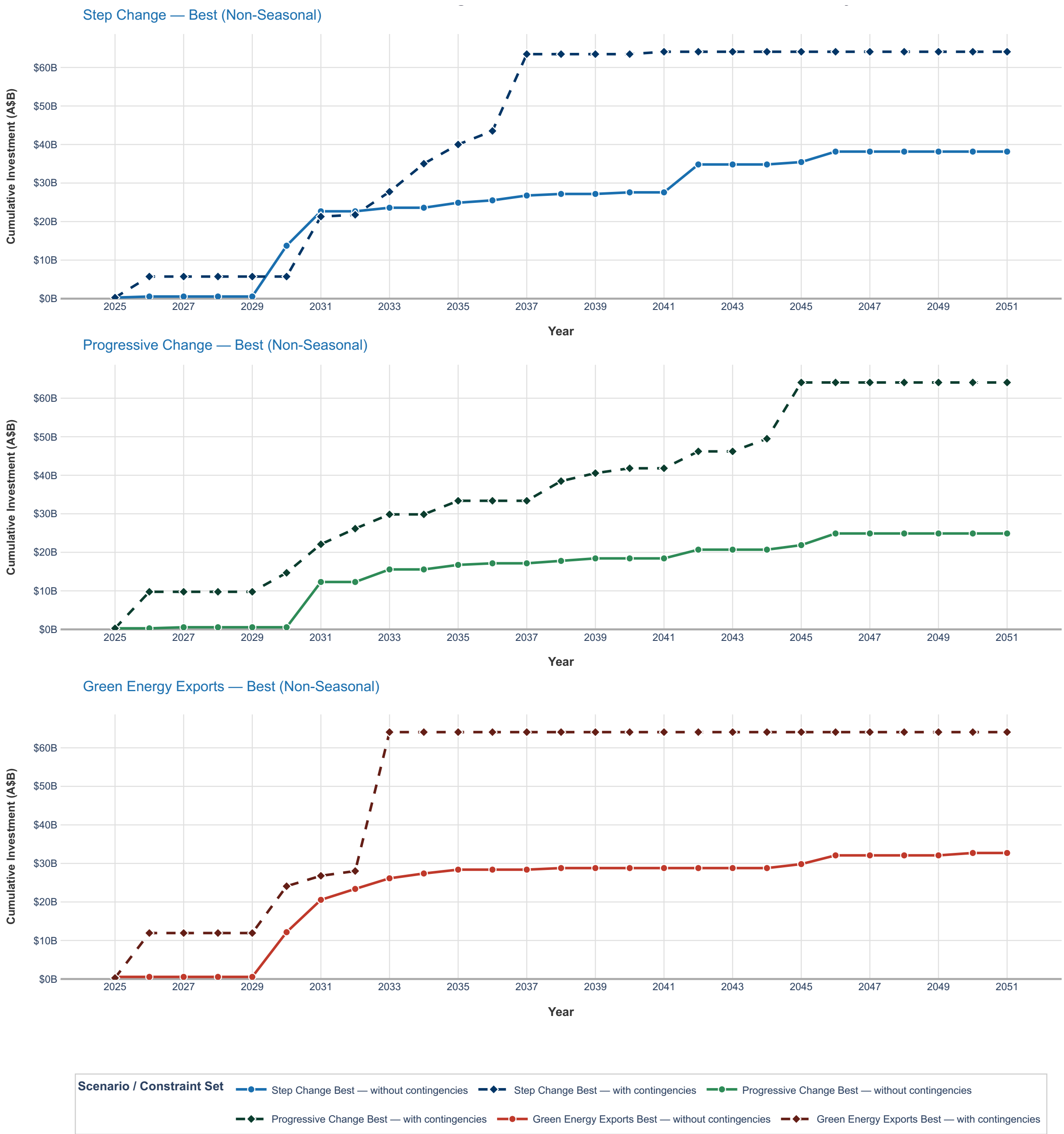


Figure 6.4 Yearly cumulative investment cost comparison for all three scenario's (Step Change, Progressive Change, and Green Energy Exports) best representation with and without critical contingencies

All three pathways converge to an identical security-constrained terminal investment of approximately A$64.1B by 2051. This convergence is not a coincidence: once N-1 feasibility is enforced under the critical-contingency set determined in Chapter 4, the binding constraints shift from scenario-specific loading patterns to the absolute requirement that the network remain solvable after the loss of any retained critical element. Because the same critical contingencies apply across all three scenarios, they are properties of the network topology, not of the demand and generation pattern, thus the resulting security overlay forces the same terminal portfolio in every case.

The increment in investment imposed by the security overlay varies substantially with scenario. Under Step Change, the increment is A$25.9B (+68 %); under Progressive Change it is A$39.2B (+157 %); and under Green Energy Exports it is A$31.4B (+96 %). These differences reflect the gap between each scenario's pre-security N-0 commitment and the universal security-constrained envelope: the Progressive Change pathway, with the lowest pre-security commitment (A$24.9B), faces the largest absolute and proportional security uplift because its lean pre-security network has the least redundancy against critical-element outages. The Step Change pathway, which had committed earlier and more substantially to backbone infrastructure such as VNI West, requires the smallest security top-up.

The security-constrained pathways are no longer dominated by the back-loaded build profile that characterizes the N-0 best cases. Under security constraints, augmentation is brought forward into the late 2020s and early 2030s, the Step Change schedule, for example, shows A$5.5B committed in 2026 alone (compared with only A$0.28B under the N-0 best schedule), reflecting the immediate need for redundant capacity on the QNI and CNSW-SNW corridors. This temporal acceleration has direct implications for transmission planning approvals, supply-chain capacity, and project delivery windows: the security-constrained schedules require a sustained commitment of A$5-8B per year through the early 2030s, which is at the upper edge of the NEM's historical delivery capability.

6.4.4 Timing of investments with vs without critical contingencies

The timing of investment provides an additional layer of planning insight beyond the pathways presented in Section 6.1. While the previous section compared the overall scale and composition of the selected pathways, the present comparison focuses on when reinforcements are brought forward under different representative cases and how strongly the timing of the pathway changes across scenario families. This distinction is important because earlier investment usually indicates more persistent structural stress, whereas later investment is more indicative of conditional or progressively emerging needs.

Figure 6.5 compares the annual number of selected investments across the Step Change, Progressive Change, and Green Energy Exports scenarios in best representations with and without critical contingencies. A clear pattern is visible across all three: the pathway becomes progressively more front-loaded as the operating condition becomes more stressed. In particular, the Green Energy Exports pathway produces the strongest concentration of early-year investments indicating that less favorable post-contingency operating conditions. By contrast, the Step Change and Progressive Change pathways are more staged over time, with investments distributed across a smaller number of key build periods rather than concentrated in very early spikes.

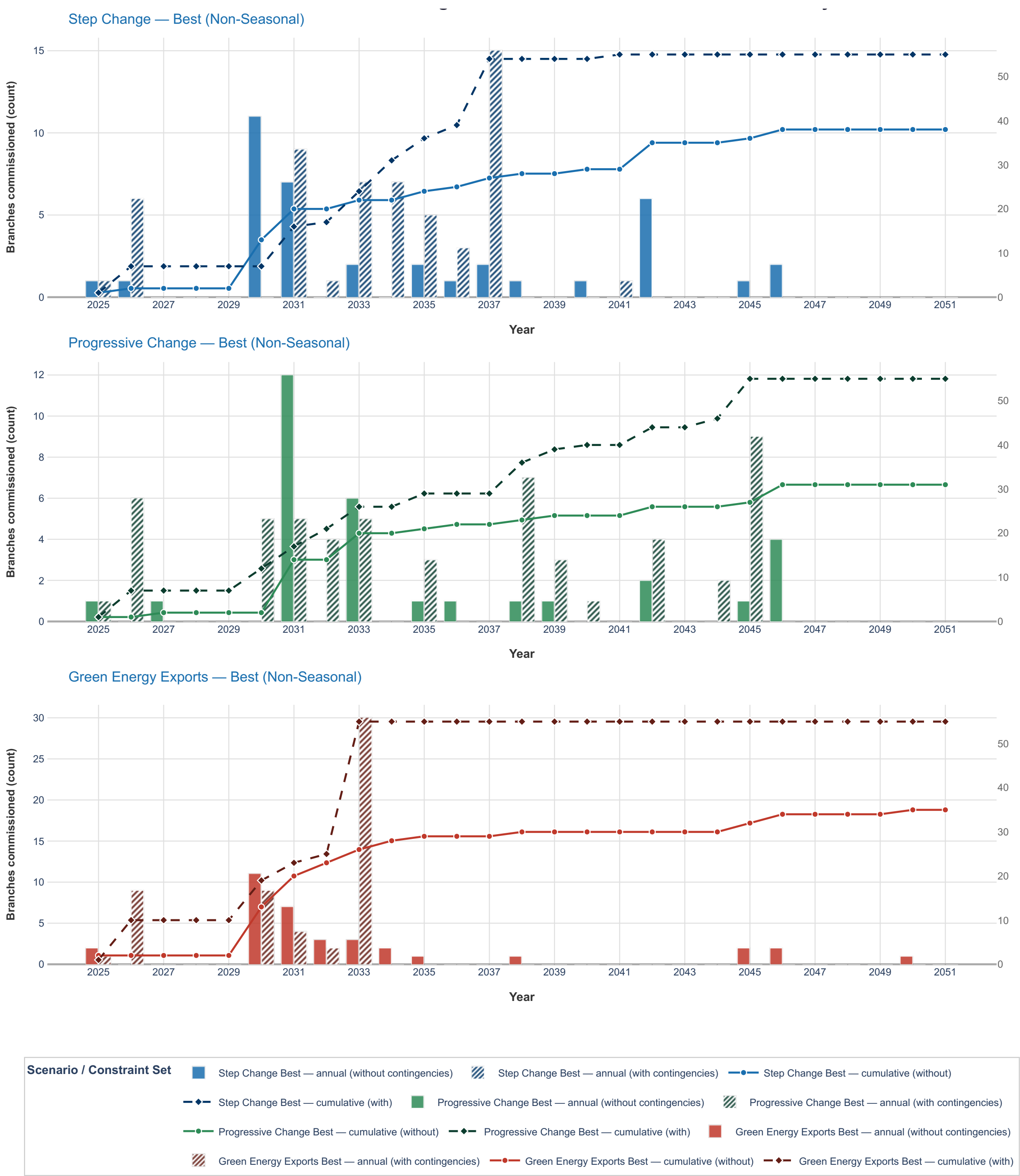


Figure 6.5 Annual number of selected investments across Step Change, Progressive Change, and Green Energy Exports scenario best representation along with the yearly cumulative costs

6.5 BESS Utilization and Role

Since storage capacity is specified exogenously in the present study, the more informative comparison lies not in installed volume but in operational use. The role of BESS is therefore examined through its utilization pattern, its daily charging and discharging behavior, and the extent to which this behavior changes once contingency constraints are enforced. This is particularly important in a time-sequential planning setting, where the value of storage depends not only on its rating but on how actively it is used to move energy across time under changing system conditions. Note the model preserves the initial and final state-of-charge values through constraints in daily operation.

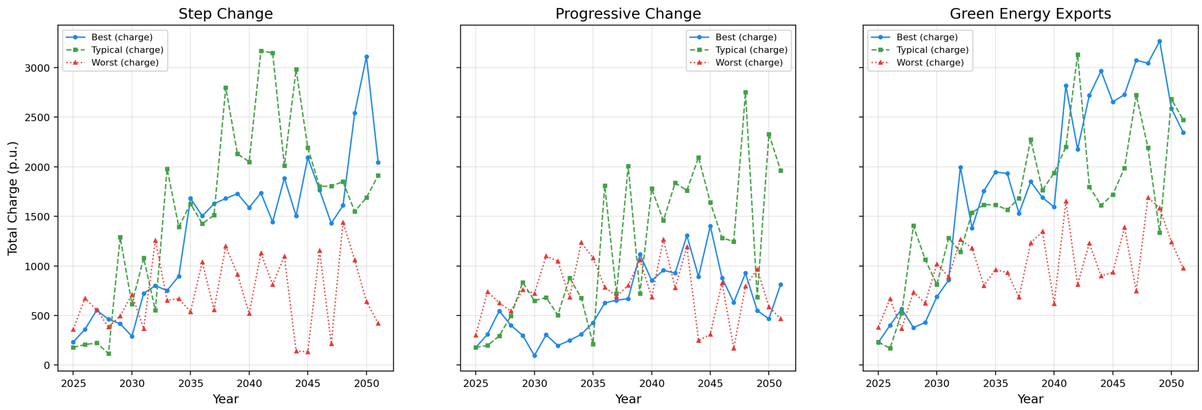


Figure 6.6 Annual total BESS charging across representative cases under different scenarios.

As shown in Figure 6.8, annual BESS charging increases over the planning horizon under all three scenario families, indicating that storage becomes progressively more active as renewable penetration rises and the system relies more heavily on temporal shifting. The broadest increase is observed under Step Change and Green Energy Exports, while Progressive Change remains more moderate. This is consistent with the wider pathway results: scenarios with stronger renewable build-out and higher transfer pressure also create greater need for storage-mediated balancing.

The comparison across representative cases is also revealing. In most years, the Best and Typical Cases show higher charging volumes than the corresponding Worst Case. This suggests that a more stressed operating profile does not necessarily translate into greater storage utilisation in a simple monotonic sense. Instead, the more severe cases appear to provide fewer opportunities for recharge, implying that BESS operation is shaped not only by the need for support, but also by the availability of surplus energy that can be absorbed and shifted. In this sense, the BESS results are consistent with a system that becomes more energy-constrained, rather than simply more power-constrained, as operating stress increases.

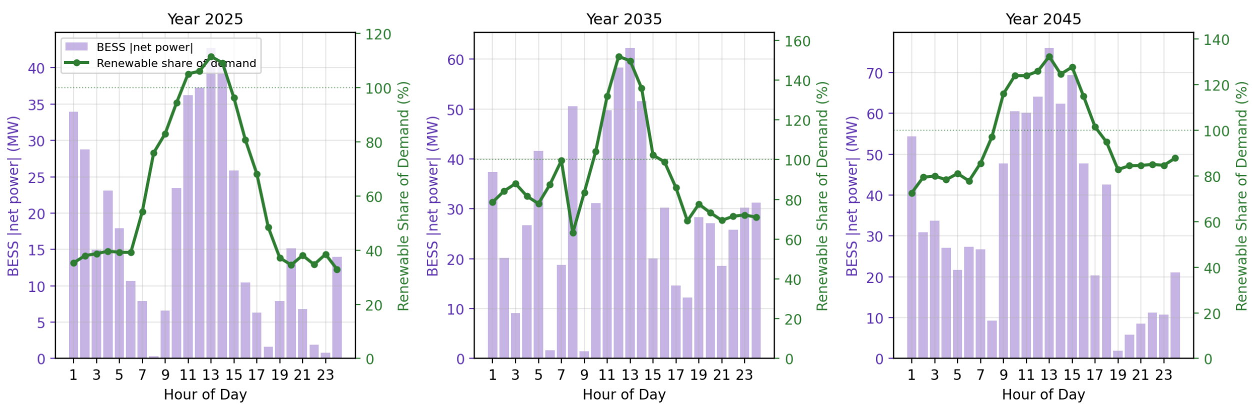


Figure 6.7 Illustrative daily BESS activity in selected years for the Step Change Best Case, showing the hourly BESS active power together with renewable penetration over a representative day.

A more detailed view is provided by Figure 6.9, which illustrates daily BESS activity in selected years for the Step Change Best Case. The figure shows that BESS activity becomes more pronounced as the system evolves from 2025 to 2045, with higher hourly dispatch levels in the later years. This increase occurs alongside a marked rise in renewable penetration, suggesting that storage is increasingly being used to absorb and shift renewable-rich output within the day rather than serving only as a marginal balancing resource.

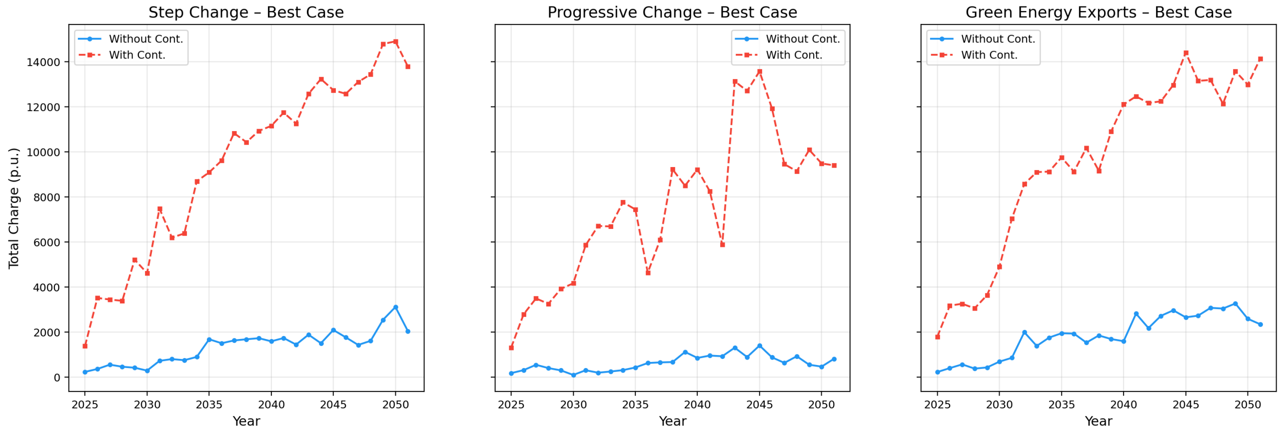


Figure 6.8 Annual BESS charging in the Best Case with and without contingency modelling under different scenarios.

The daily profile also helps clarify the role of BESS in operational terms. In the earlier year, BESS activity is more limited and remains within a narrower range. By 2035 and especially 2045, the hourly profile becomes both larger in magnitude and more sustained across the central part of the day. This indicates that as renewable penetration rises, storage becomes more embedded in the daily operation of the system, acting as a temporal balancing mechanism that helps manage the mismatch between renewable production and system needs.

The effect of security constraints is shown more directly in Figure 6.10, which compares annual BESS charging in the Best Case with and without contingency modelling. In all three scenario families, the with-contingency trajectories lie consistently above the corresponding runs without contingency constraints, and the gap widens over time. This indicates that explicit security modelling materially increases the operational use of storage. The effect is strongest under Step Change and Green Energy Exports, where the difference becomes large and persistent in the later years, while Progressive Change shows the same direction of change at a lower overall level.

This result is significant because it shows that security constraints do not only affect the selected network pathway. They also increase the operational value of BESS by creating a more constrained environment in which storage must work harder to absorb, reposition, and release energy in support of feasible system operation. In other words, the contribution of BESS in this framework is not limited to generic renewable smoothing. Under explicit security constraints, storage becomes a more active component of system operability. Further, the results show that the role of BESS strengthens in two ways over the planning horizon. First, its utilisation increases as the system becomes more reliant on renewable generation and temporal shifting. Second, this role is further intensified once contingency constraints are included. The combined picture is that BESS acts not only as a flexibility resource for routine balancing, but increasingly as an operational support mechanism in a system with growing renewable variability, tighter transfer conditions, and stronger security requirements.

6.6 Network Utilization and Congestion

This section examines how the cumulative investments reshape the network topology relating to the congestion patterns observed over the planning horizon. The purpose here is not simply to show that more investment is added over time, but to assess whether those additions materially change how heavily the network is used and how congestion evolves under different operating conditions.

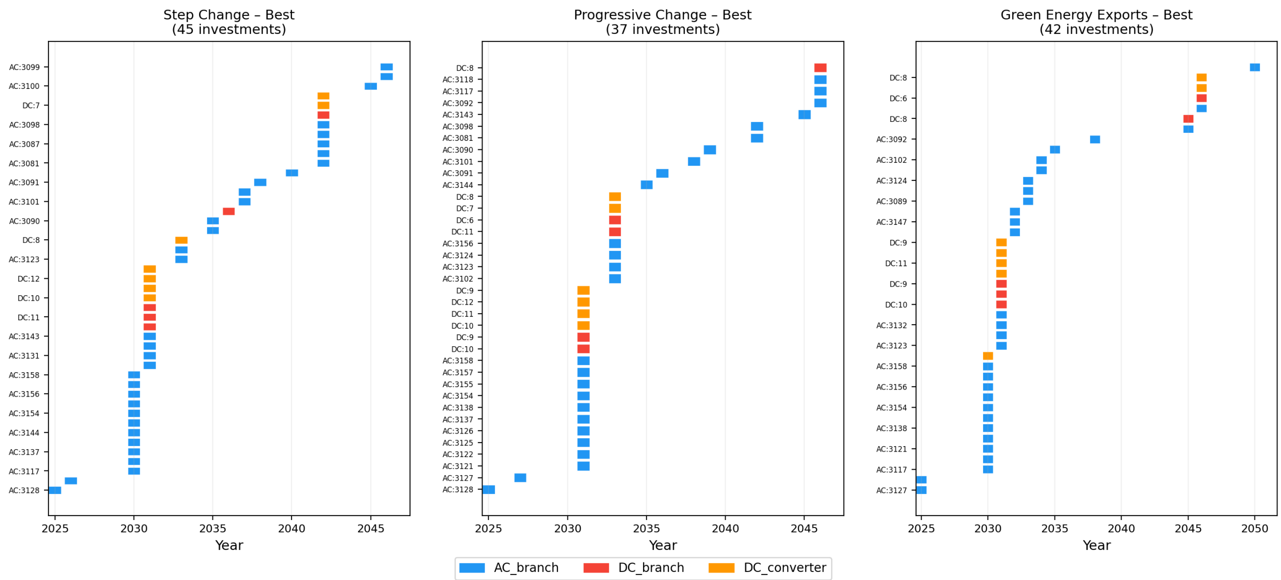


Figure 6.9 Evolution of the selected network topology in the best representation under different scenarios.

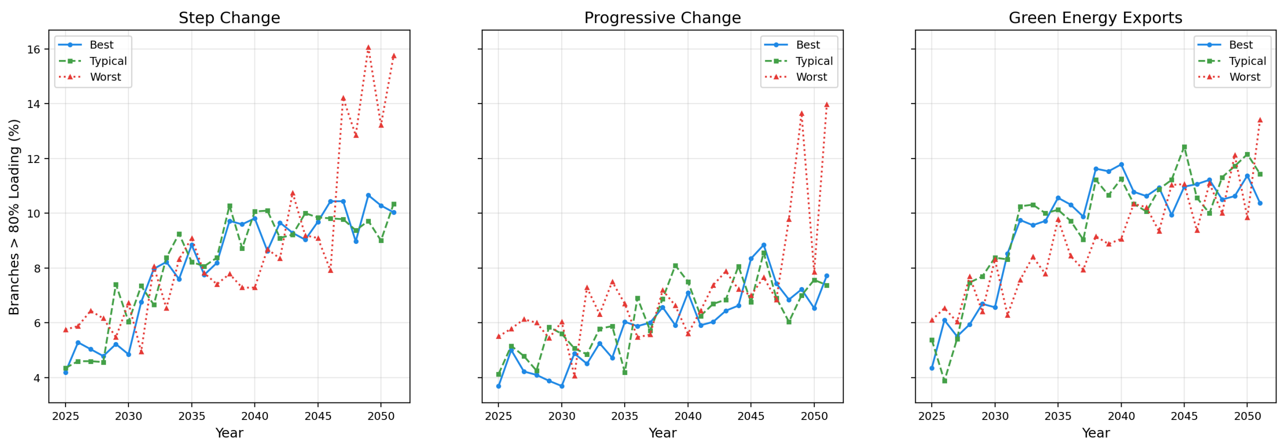


Figure 6.10 Congestion frequency across the Best, Typical, and Worst Cases under different scenarios.

The three scenario families in best representation as shown in Figure 6.11 follow the same broad pattern, but the intensity of the topology evolution differs. Under Progressive Change, the network develops more gradually, with fewer visible additions in the earlier years and a more staged build-out overall. Step Change shows a denser accumulation of new elements over time, while Green Energy Exports exhibits the strongest overall structural growth, with the later-year topology appearing noticeably more reinforced than in the other two pathways. This is consistent with the earlier pathway and timing results: as the system scale and renewable transfer pressure increase, the selected network becomes more heavily augmented, particularly along strategic flow paths.

This evolving topology forms the background for the congestion results in Figure 6.12. Across all three scenario families, congestion frequency increases over time, indicating that network stress becomes more persistent as renewable penetration deepens and the spatial mismatch between generation and demand becomes more pronounced. The upward trend is visible in all representative cases, but its magnitude differs materially. In each scenario family, the best case remains the least congested, the typical case lies above it, and the worst case shows the highest congestion frequency. This ordering is important because it shows that congestion is not simply a function of long-term system growth alone. It also depends on the operating profile represented by the case construction.

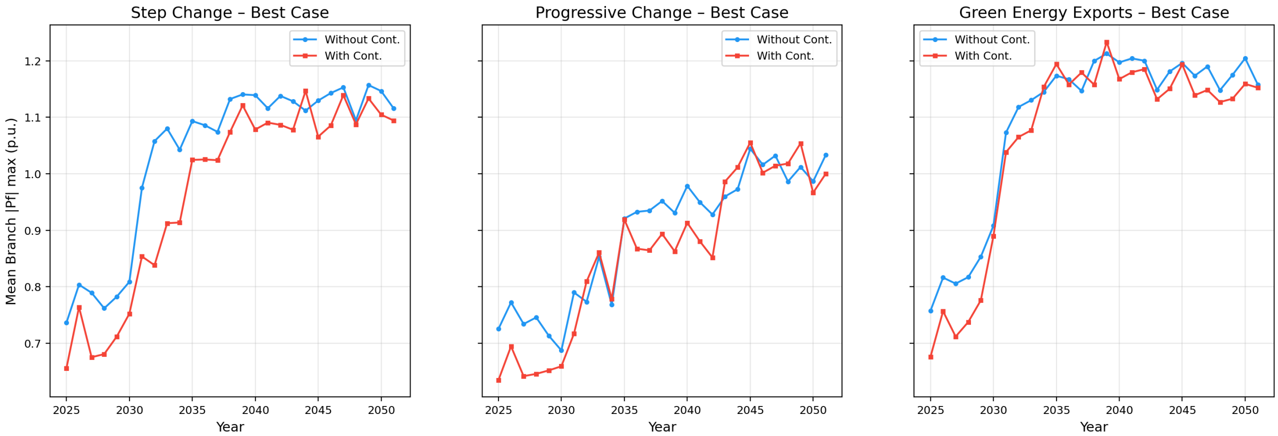


Figure 6.11 Average network congestion in the best representation with and without contingency modelling under Step Change, Progressive Change, and Green Energy Exports scenarios

The differences across scenario families are also informative. Progressive Change remains the most moderate of the three, with congestion increasing steadily but from a lower base and with a more gradual slope. Step Change shows a stronger rise over the planning horizon, particularly in the Typical and Worst Cases, indicating that congestion becomes more persistent once the system enters the more rapid phase of renewable-led transition. Green Energy Exports is the most structurally demanding case. Its congestion frequency remains elevated across much of the horizon and rises to the highest sustained levels among the three scenario families. This suggests that in the export-oriented pathway, reinforcement is responding not only to higher total system scale, but to a more persistent need to move large volumes of renewable energy across the network.

The topology is clearly being reinforced over time, yet congestion continues to rise. The implication is not that the selected investments are ineffective. Rather, it suggests that the underlying growth in system stress is large enough that reinforcement is acting to contain congestion, not eliminate it. In that sense, the pathway is keeping pace with a progressively more difficult operating environment, but not fully exhausting the structural pressure created by the evolving generation mix.

The effect of security constraints is shown more directly in Figure 6.13, which compares average network congestion in the best representation with and without explicit contingency modelling. Unlike the investment timing results in Section 6.4, the differences here are not dramatic in a visual sense, but they are systematic. In all three scenario families, the with-contingency trajectories remain below the corresponding runs without contingency constraints for most of the horizon. This indicates that the broader reinforcement set selected under explicit security requirements does, in fact, reduce average network congestion at the system level.

The scale of this effect varies across scenarios. Under Step Change, the separation between the two trajectories becomes more noticeable in the later years, suggesting that contingency-constrained reinforcement increasingly relieves network pressure as the system becomes more stressed. Progressive Change shows the smallest gap, which is consistent with its more moderate pathway expansion and lower overall congestion level. Green Energy Exports again shows a clear benefit from contingency-constrained planning, with the with-contingency curve remaining consistently lower than the no-contingency case over much of the horizon. This indicates that in a more demanding system, security-driven reinforcement not only improves post-contingency resilience but also lowers average congestion under intact conditions by strengthening the same structurally stressed corridors.

6.7 Curtailment of Renewables

The congestion results show that network pressure remains persistent even after progressive reinforcement, particularly under more demanding operating conditions. One immediate consequence of this pressure is that part of the available renewable output cannot be fully accommodated. In that sense, renewable curtailment is not a separate phenomenon from the pathway results discussed earlier, but a direct indicator of how effectively the evolving network can absorb and transfer renewable energy as the system develops. Figure 6.14 shows the estimated implicit curtailment across the three scenario families and representative cases. Although the metric is restricted to the REZ variable renewable fleet and is derived from available energy relative to dispatch, it still provides a clear picture of how much renewable output remains constrained by the evolving system. Across all three representative cases, the curtailment level tends to rise over the planning horizon, indicating that renewable growth is outpacing the system's ability to utilize all available output. The trajectories are relatively close across the three scenario families, which suggests that this is a broad structural issue rather than a scenario-specific outlier.

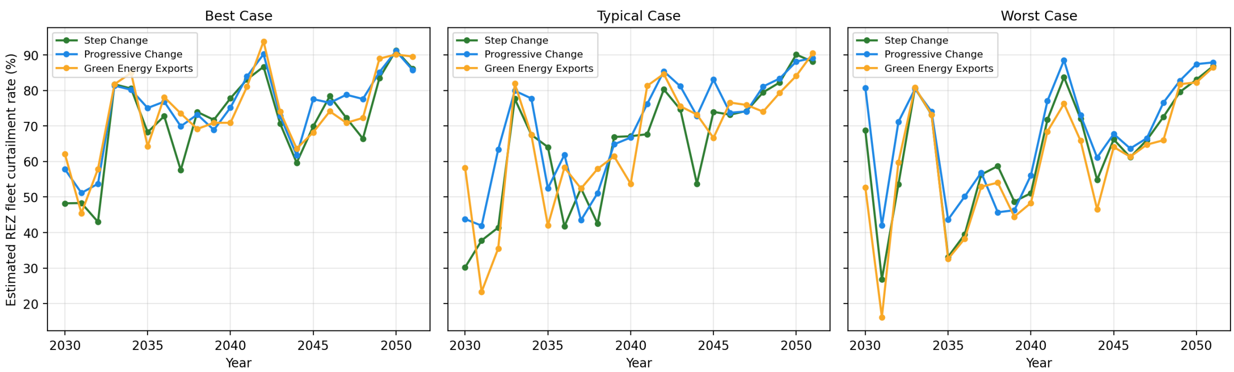


Figure 6.12 Estimated implicit curtailment of REZ variable renewable energy across representations under scenarios

At the same time, the case comparison remains informative. In most years, the Worst Case tends to produce slightly higher curtailment than the Best and Typical Cases, especially in the later part of the horizon. This is consistent with the earlier congestion results, where the more stressed operating profiles generated stronger network pressure and a larger need for reinforcement. The differences are not extreme, but they are persistent enough to indicate that curtailment responds systematically to the severity of the operating profile.

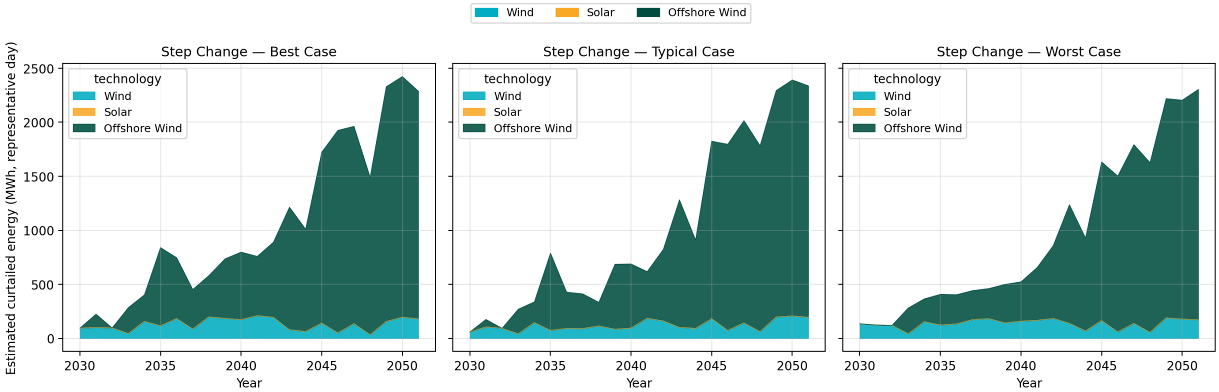


Figure 6.13 Estimated curtailed energy by renewable technology under Step Change for different representations.

A more detailed view is provided in Figure 6.15 by decomposing the estimated curtailed energy by technology under Step Change. A clear result is that offshore wind dominates the curtailed volume over time, while wind and solar remain comparatively smaller contributors. This dominance becomes especially pronounced in the later years, when the offshore wind component grows sharply and accounts for most of the increase in total curtailment. The implication is that the main curtailment burden in the selected pathway is not evenly shared across renewable technologies but is concentrated in those resources whose growth is strongest and whose output is most exposed to transfer limitations.

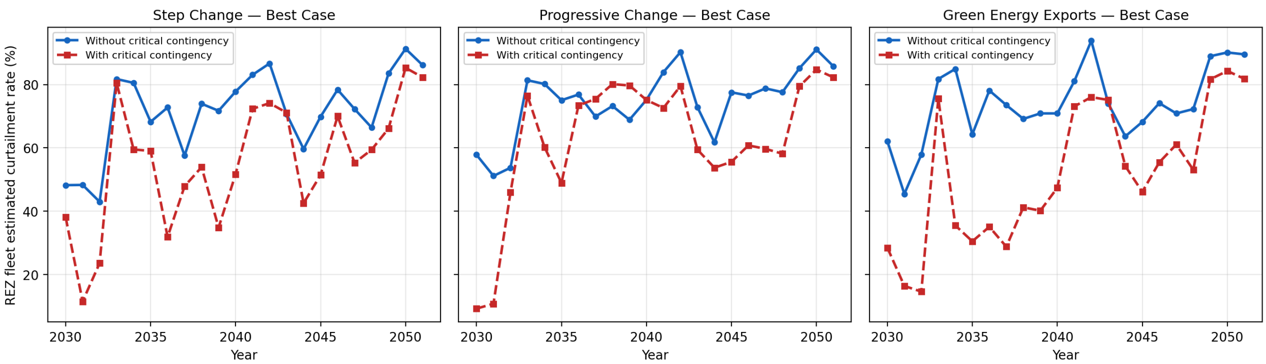


Figure 6.14 Comparison between estimated implicit curtailment in the best representation with and without critical contingencies under different scenarios.

The effect of contingency modelling on estimated implicit curtailment in the best representation of the three planning scenarios is illustrated in Figure 6.16, where the contrast is more pronounced. Across all scenario families, the trajectories obtained with contingency modelling remain below the corresponding cases without contingency constraints for much of the planning horizon. This suggests that the broader and more security-aware transmission pathways identified under contingency modelling are also more effective in reducing renewable curtailment. The effect is particularly evident in the Progressive Change and Green Energy Exports scenarios, where the separation between the two trajectories remains significant over extended periods of the planning horizon.

Part II Projected Assessment of System Adequacy

This part of the report focuses on the projected assessment of system adequacy under long-term planning pathways for the NEM. The analysis is conducted based on the optimal development pathways derived from the time-sequential SCTNEP framework across representative scenarios presented in Part I. It shifts the focus from network feasibility to evaluating the availability and sufficiency of generation and storage resources in meeting electricity demand under uncertainty, across ultra-short-term, short-term, medium-term, and long-term horizons with full time-series resolution.

7 Introduction

7.1 Increasing Renewable Penetration and Time-Coupled Energy-Limited Storage Systems in the NEM and the Need for Projected System Adequacy Assessment

The NEM is undergoing a structural transformation of unprecedented pace and scale. Accelerated retirement of dispatchable coal generation, rapidly growing penetration of variable renewable energy, and increasing electrification of industry and transport are collectively reshaping the risk profile of the power system. This transition creates both the imperative and the opportunity to reassess how system adequacy is measured and planned for over the long term.

Historically, resource adequacy was assessed through deterministic metrics such as reserve margins, installed capacity ratios, and peak-demand coverage thresholds that were well-suited to systems dominated by flexible thermal generation. In such systems, capacity was broadly synonymous with availability. However, as AEMO's 2025 Electricity Statement of Opportunities (ESOO) makes clear, this equivalence no longer holds [63]. The 2025 ESOO explicitly identifies reliability risks arising not only from shortfalls in instantaneous generation capacity, but from shortfalls in energy production over periods of hours, days, or weeks. AEMO notes that due to the changing generation and storage mix in the NEM, sustained energy production over longer periods is likely to become a more dominant factor in reliability assessments than the availability of instantaneous energy production capacity.

This shift reflects the growing role of energy-limited resources particularly utility-scale battery storage, whose contribution to system reliability is inherently time-coupled. Unlike thermal plant, which can sustain output as long as fuel is available, storage systems must be charged before they can discharge. Their adequacy value depends not only on installed capacity (MW) but on the energy they can deliver across an entire stress event (MWh), the state of charge at the onset of that event, and the availability of renewable generation to recharge them during or between periods of system stress. The capacity metrics alone cannot capture these dynamics.

The 2025 ESOO reinforces the importance of this forward-looking perspective. Under its more optimistic development outlook, which assumes delivery of generation and storage to the targets and timings of federal and state government programs, AEMO forecasts sufficient capacity to meet reliability standards across most NEM regions over the next decade. However, under its committed-only outlook, which reflects recently observed project delays, near-term reliability challenges are identified for Queensland and South Australia, with longer-term gaps forecast across all mainland regions if development trajectories are not maintained. AEMO notes that while the pace of generator commissioning has increased from 4.4 GW in 2024–25 to between 5.2 and 10.1 GW expected per year over the following five years, delivering new generation, storage, transmission, and consumer energy resources on time and in full at even greater pace will be essential for the ongoing reliability of the NEM.

Projected assessment of system adequacy has to be carried out at different time-scales such as short-term, medium-term, and long-term time horizons [11]. Probabilistic system adequacy methods are well suited for long- and medium-term planning, but they have important limitations in representing the operational detail required for high-renewable high-storage systems. They typically simplify or omit inter-temporal constraints, making it difficult to accurately capture the dynamics of energy-limited storage (e.g., state-of-charge evolution, cycling, and duration constraints). Similarly, generator operational characteristics such as ramp rates, minimum up/down times, and start-up constraints are often approximated or neglected. Moreover, network modelling is often overlooked. As a result, while these methods provide computationally-efficient valuable insights into system adequacy and capacity needs, they may not fully reflect short-term system flexibility requirements. For short-term or operational analyses, more detailed chronological models that explicitly represent inter-temporal dynamics and unit-level constraints are necessary.

Overall, the sensitivity of the system adequacy outcomes depends on the timing and composition of new investment, and the corresponding need for a time-sequential planning framework that can represent this uncertainty rigorously. The projected system adequacy assessment presented in this project is designed to provides a planning-oriented view of system sufficiency, identifying adequacy trends, scenario sensitivities, and potential pressure points across time horizons that complements the transmission security analysis in Part I and is calibrated to the structural changes now underway in the NEM.

7.2 Scope of the Projected System Adequacy Assessment in this Project

Building on the rationale established in Section 7.1, this section sets out the scope, structure, and methodological architecture of the Projected Assessment of System Adequacy undertaken in this project. The assessment is configured to operate over the full development pathways identified in Part I and to span the three planning time horizons ultra-short-term, short-term, medium-term, and long-term. Each horizon is treated with a methodology and a temporal resolution chosen to match the dominant adequacy mechanisms operating at that timescale, so that the complete framework yields a coherent, multi-scale picture of how the future NEM is expected to behave under the structural changes described in Chapter 6.

The ultra-short-term assessment is carried out for 1-week with 30-minute resolution based on time-sequential detailed unit-commitment model that respects all unit-level operational constraints including minimum up- and down-times, ramp-rate limits, start-up costs, minimum stable generation levels and storage state-of-charge of the storage systems. The Siena tools such as PowerSimulations.jl is used to perform these simulations.

The short-term assessment in this project combines Monte Carlo sampling over the joint distribution of demand, renewable generation, hydro-availability, and forced-outage realizations evolving at 30-minute resolution across a 1-year horizon representing near-term operational conditions following committed developments. This Monte Carlo framework provides probabilistic coverage of the coupled stochastic input space, ensuring that the resulting adequacy indices are not dependent on any single weather pattern or outage realization. The medium-term and long-term assessments are performed on 6-year and 20-year projections respectively. These assessments are performed using PRAS.jl.

Across all three horizons, this project reports a consistent set of adequacy indices designed to characterize reliability outcomes from complementary probabilistic and energy-volume perspectives. Each index captures a different facet of system adequacy and reporting them together avoids the well-known limitations of relying on any single indicator. Table 7.1 summarizes the indices used in this project; the rationale for each is explained in the narrative below.

Table 7.1 Adequacy indices reported in the project

Index	Full name	Definition	Units
LOLP	Loss of Load Probability	Probability that demand exceeds available supply in a given trading interval.	Dimensionless (0–1) per interval; averaged across simulations.
LOLE	Loss of Load Expectation	Expected number of intervals (or hours, days) per year in which load is not fully met.	Hours/year (LOLE-h) or days/year (LOLE-d).
LOLH	Loss of Load Hours	Total expected hours per year of any unserved-energy event.	Hours/year.
LOLF	Loss of Load Frequency	Expected number of distinct unserved-energy events per year.	Events/year.
LOLD	Loss of Load Duration	Expected duration of an unserved-energy event when one occurs (LOLH ÷ LOLF).	Hours/event.
EUE	Expected Unserved Energy	Expected total energy not supplied to load in a year, summed across all unserved-energy events and weather/outage realizations.	MWh/year or GWh/year.
USE	Unserved Energy (NEM-aligned)	Annual unserved energy expressed as a percentage of regional energy demand. Direct point of comparison with AEMO's reliability standard (0.0006 % per region per year).	% of regional annual demand.
LOLPp	Pool / Single-Event LOLP	Probability that any single trading interval in a defined event window fails to meet load — used in operational ST-PASA reporting.	Dimensionless (0–1).
RM	Reserve Margin	Available capacity in excess of forecast peak demand; reported alongside probabilistic indices for comparability with legacy planning practice.	% of peak demand.
ELCC	Effective Load-Carrying Capability	Equivalent firm capacity contribution of variable and energy-limited resources, derived by parametric capacity sweeps.	MW per unit of installed capacity.

The choice to report multiple indices reflects the fact that no single metric can fully characterize adequacy in a system dominated by energy-limited resources. The probability-based indices (LOLP, LOLE, LOLF) describe the frequency and likelihood of supply shortfalls without quantifying their energy magnitude; conversely, the energy-based indices (EUE, USE) quantify the consequence of supply shortfalls but conflate many short events with a single long event of equal aggregate energy. Reporting both classes permits the analyst to distinguish, for example, between a system that fails for many short low-MW events (high LOLF, low USE per event) and one that fails rarely but severely (low LOLF, high LOLD, large per-event USE). The policy implications of these two regimes are quite different: the first calls for fast-response capacity such as batteries; the second calls for deep-energy resources such as pumped hydro or long-duration storage and the index set is therefore deliberately constructed to support that distinction.

The assessment framework in this part of the report is calibrated against the transmission-investment pathways produced in Part I. The candidate scenarios: Step Change, Progressive Change, and Green Energy Exports together with their three representations (best, typical, worst), define the development pathways being assessed. The transmission topology, generation and storage build, and security overlay from Sections 6.1–6.4 are imported as exogenous inputs, allowing the adequacy assessment to focus exclusively on the availability and sufficiency of generation and storage resources to meet electricity demand under uncertainty.

8 Current Practice, Methodologies, Tools and Implementation in Projected Assessment of System Adequacy

8.1 Current Industry Practice in Projected Assessment of System Adequacy

Projected adequacy assessment in modern power systems has evolved through three loosely overlapping phases. The first, established in the 1970s and 1980s, used analytical convolution methods on capacity-outage probability tables and load-duration curves to produce reliability indices such as Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE) under the assumption that capacity availability was the binding adequacy constraint [64]. The second phase, dominant from the 1990s through the 2010s, retained these probabilistic foundations but added sequential Monte-Carlo simulation to capture chronological correlations in load and supply, particularly under increasing wind penetration [65], [66]. The third and current phase, driven by the structural changes described in Section 7.1, integrates explicit time-coupled storage representation, weather-correlated renewable resource modelling, and increasingly the network-flow constraints and security obligations that the legacy frameworks treated as separable [67], [68], and [69]

System operators in the major interconnected grids have moved at different paces along this trajectory. In North America, NERC's annual Long-Term Reliability Assessment continues to report a deterministic Reserve Margin screen as the headline adequacy indicator but increasingly supplements it with probabilistic LOLE and EUE assessments produced by individual Reliability Coordinators and ISOs [70]. MISO and SPP have publicly moved to probabilistic Effective Load-Carrying Capability (ELCC) accreditation for renewable and storage resources [71]; [72], while ERCOT and PJM have reformed their capacity-accreditation rules to recognize the duration-dependence of storage adequacy contributions [73]; [74]. In Europe, the ENTSO-E European Resource Adequacy Assessment (ERAA) has since 2021 required Member States to use a chronological Monte-Carlo dispatch with explicit climate-year sampling [75], and France's RTE uses the open-source ANTARES platform for both ERAA submissions and its national long-term adequacy outlook [76].

AEMO's adequacy framework for the NEM mirrors this international trajectory. The ESOO provides a ten-year LT outlook based on a probabilistic chronological dispatch run across representative weather and demand traces, reporting USE against the NEM Reliability Standard of 0.0006 % per region per financial year [77]. The ISP extends this to a 25-to-30-year horizon and co-optimizes generation and transmission investment under explicit climate, demand, and policy scenarios [78]. Operationally, the published Short-Term PASA (ST-PASA) and Medium-Term PASA (MT-PASA) processes provide rolling 7-day and 24-month adequacy screens at half-hourly and daily resolution respectively [79]. In its 2025 ESOO, AEMO observed explicitly that the structural changes in the NEM are shifting the binding adequacy mechanism from instantaneous-capacity shortfall to sustained-energy shortfall and signaled a corresponding evolution of its adequacy assessment methodology [77].

Three methodological themes recur across all of these contemporary practices. First, probabilistic chronological simulation is now the industry-default approach: the deterministic capacity-margin and load-duration methods of the 1980s remain in use only as ex-post screens or planning-rule tests, not as primary adequacy evidence. Second, the assessment horizon is increasingly multi-scale, with separate but consistent ST-, MT-, and LT-PASA processes feeding a coherent reliability narrative [69]. Third, the adequacy assessment is increasingly coupled to investment and operational planning both ENTSO-E and AEMO now explicitly integrate adequacy outputs into their transmission-and-generation expansion frameworks, recognizing that an adequacy index decoupled from the underlying network and operational feasibility can mislead investment decisions [75], [78], [80].

The methodological imperatives driving the current phase are the same imperatives that shape the design of this project's projected assessment of system adequacy in Sections 7.1 and 7.2: that capacity is no longer synonymous with availability; that energy-limited storage adequacy contributions are time-coupled and cannot be summarized by a single capacity-credit figure; and that network security constraints, increasingly binding under high renewable transfer patterns, must be represented explicitly within the adequacy model rather than handled as a downstream feasibility check [67], [81], [82]

8.2 Current Tools and Platforms for Projected Assessment of System Adequacy

The methodological transition described in Section 8.1 has been accompanied by and to a large extent enabled by a rapid expansion of the software ecosystem supporting probabilistic, chronological adequacy modelling. Contemporary tools fall into three broad classes: established commercial platforms (PLEXOS [26], PROMOD [27], Aurora [83], GridView [84], Antares-Simulator [85]; open-source planning and operational platforms with adequacy modules (PRAS, Sienna-PowerSimulations.jl, GridPath [44], Calliope [86], OSeMOSYS [87], Backbone [86]); and bespoke utility-internal codes that remain in active use at several large system operators. Table 8.1 summarizes the most widely used tools relevant to this project.

Among commercial platforms, PLEXOS retains the dominant share of the industry-PASA workload because it integrates stochastic Monte-Carlo, chronological UC + ED, transmission DC-OPF, and multi-fuel co-optimization in a single environment. Its limitations are familiar and largely structural: closed-source operation makes peer-reviewed reproducibility difficult; institutional licensing costs preclude broad academic use; and scaling to very-high-resolution long-horizon studies (e.g., 8,760 h × 27 years × hundreds of Monte-Carlo realizations on a network with thousands of buses) often forces practical compromises in either temporal resolution, network detail, or sample size. PROMOD and Aurora occupy adjacent niches with complementary trade-offs between security-constrained operational fidelity (PROMOD) and long-horizon expansion accessibility (Aurora).

Table 8.1 Selected Tools and Platforms for Projected System Adequacy Assessment

Tool / platform	License	Capability	Strengths / limitations
PLEXOS (Energy Exemplar)	Commercial	Mixed-integer chronological UC + ED with stochastic Monte-Carlo, transmission DC-OPF, multi-stage stochastic optimization, gas/water co-optimization. Used by AEMO, AESO, NYISO, several ISOs.	Industry-standard rich feature set; strong vendor support; native Monte-Carlo and chronological storage. Closed-source; licensing cost-prohibitive at large institutional scale; reproducibility and peer-

			review challenges; slow for very large hourly LT studies.
PROMOD (Hitachi Energy)	Commercial	Production-cost simulation with security-constrained UC, locational marginal-price reporting, contingency screening. Common in North American ISO planning.	Strong contingency/security modelling and LMP outputs. Licensing and data-format constraints; limited probabilistic adequacy module compared to PLEXOS.
Aurora (ENVERUS)	Commercial	Long-term capacity expansion with chronological dispatch and LT-MT adequacy reporting. Common in US Western Interconnection studies.	Approachable workflow; reasonable performance at hourly resolution. Less detailed UC and security representation than PLEXOS/PROMOD.
ANTARES (RTE)	Open-source (BSD-3)	Chronological probabilistic Monte-Carlo dispatch with hydro reservoir modelling, climate-year sampling, transmission flow-based market coupling. Used for ENTSO-E ERAA and RTE bilan prévisionnel.	Open and ENTSO-E-aligned; very strong climate-year and hydro-coupling support. Limited intra-hour resolution; weaker UC representation than commercial tools.
PRAS (NREL)	Open-source (BSD-3, Julia)	Pure resource-adequacy assessment using sequential Monte-Carlo overload, VRE and outage realizations on a transportation (max-flow) network model. Designed for very fast LOLE/EUE/USE evaluation.	Excellent computational scaling for large probabilistic studies; open and reproducible; strong storage state-of-charge handling. By design omits unit-commitment and DC/AC-OPF; not a substitute for operational simulation.
Sienna / PowerSimulations.jl (NREL, Julia)	Open-source (BSD-3, Julia)	Modular ecosystem for production-cost simulation, capacity expansion, and dynamic studies. Includes PowerSystems.jl (data), PowerSimulations.jl (operations), and PowerSimulationsDynamics.jl (transient).	Composable, transparent, and high-performance; integrates with PRAS for RA assessments; strong storage and reserve modelling. Steep learning curve for non-Julia users; smaller ecosystem than commercial platforms.
GridPath (Blue Marble Analytics)	Open-source (Apache-2, Pyomo)	Co-optimization of capacity expansion and operations with explicit sub hourly reliability and policy-target modelling.	Flexible and well-documented; growing user base. Less mature for large-scale chronological PASA than the commercial platforms.
Calliope, OSeMOSYS, Backbone	Open-source	Energy-system optimization frameworks supporting capacity expansion with simplified operational representation; widely used in academic scenario analysis.	Highly flexible; reproducible. Generally, too coarse operationally for rigorous adequacy assessment in storage-rich systems without targeted extensions.

The open-source ecosystem has matured rapidly over the past five years and now offers genuinely production-grade capability for adequacy work. NREL's PRAS [87] is purpose-built for resource-adequacy assessment using sequential Monte-Carlo over a transportation-flow network, with explicit storage state-of-charge tracking and outage modelling. PRAS is computationally efficient at very large probabilistic sample sizes, but by design omits unit-commitment and AC/DC-OPF and is therefore not a substitute for operational simulation. The Sienna platform comprising PowerSystems.jl for data, PowerSimulations.jl for operational and expansion modelling, and PowerSimulationsDynamics.jl for transient studies provides a modular, high-performance Julia stack that complements PRAS by supplying detailed UC + ED and capacity-expansion capability [88]; [89]. The combination of PRAS for adequacy indices and Sienna for chronological operational validation has emerged as a credible open-source counterpart to PLEXOS-based workflows in several recent NLR and DOE studies [90]. ANTARES, GridPath, Calliope, OSeMOSYS, and Backbone occupy further niches across adequacy, expansion planning, and policy-scenario analysis.

8.2.1 Implementation considerations

Translating any of these tools into a credible PASA study at the scale required in this project eighteen development pathways across the NEM, hourly chronological resolution to 2051, full Monte-Carlo coverage, and the network topology established in Part I exposes a consistent set of implementation challenges that practitioners report across both commercial and open platforms.

Hourly chronological simulation across a 27-year horizon with explicit unit-commitment and storage state-of-charge tracking produces problem sizes that exceed conventional MILP solver capacity unless the horizon is decomposed [80]. Rolling-horizon decomposition with warm-started state-of-charge handover, scenario decomposition through Benders or progressive hedging, and parallelized Monte-Carlo execution are the standard mitigation strategies [65], [91]. The trade-off between problem size, solution quality, and statistical confidence in the resulting adequacy indices is an ever-present design choice.

Chronological PASA requires consistent, region-resolved time series for demand, wind speed, irradiance, ambient temperature, hydro inflows, and rooftop-PV output across the same set of climate years used for Monte-Carlo sampling. The data themselves are often the binding constraint on study quality: gaps and inhomogeneities in historical weather records, the use of synthetic reanalysis-derived series, and the treatment of climate change in long-horizon studies all materially affect the resulting adequacy indices [92], [93]. Reanalysis datasets such as ERA5 and BARRA-R2 are now standard inputs, supplemented by historical AEMO demand traces for the NEM context.

Adequacy models historically treated network-flow and security constraints as a downstream feasibility test, but recent work has shown that this decoupling can mis-locate adequacy risk in systems with binding transmission corridors and HVDC interconnectors [93], [68]. Integration challenges fall into three groups. First, storage state-of-charge dynamics must be coupled across the entire simulation horizon periodic boundary conditions and end-of-period value functions are common but imperfect proxies. Second, HVDC links introduce control modes, converter losses, and inter-regional co-optimization rules that production-cost engines often represent only approximately. Third, N-1 (and increasingly N-1-1) security constraints must be embedded at the dispatch stage to reproduce realistic congestion and curtailment outcomes; this is the explicit motivation for the security-constrained framework adopted in Part I and inherited as input to the adequacy assessment in Part II of this project.

Adequacy results are sensitive to dozens of modelling choices Monte-Carlo seed, climate-year set, outage statistics, capacity-credit accreditation rules, dispatch-stack assumptions and inconsistent treatment across tools makes cross-study comparison difficult. The open-source ecosystem (PRAS, Sienna, ANTARES, GridPath) is materially better placed than the commercial platforms on this dimension because the underlying code, data schemas, and configuration files can be shared and audited; this is a significant motivation for the open-tool-friendly architecture adopted in this project's PASA framework.

8.2.2 Gaps and research opportunities

Despite the rapid maturation of both commercial and open-source tools, several gaps remain that are directly relevant to the design of the PASA framework adopted in this project. The most material gaps are summarized below.

- Limitations in current adequacy methodologies. Capacity-credit and convolution-based methods systematically understate the adequacy contribution of energy-limited storage during multi-day low-renewable events; sequential Monte-Carlo on a transportation-flow network (e.g., PRAS) addresses storage state-of-charge but omits unit-commitment and security constraints; production-cost engines (e.g., PLEXOS, Sienna) capture operational detail but rarely run at the Monte-Carlo sample sizes needed for confidence-bounded adequacy indices.
- Need for interoperable frameworks. No single tool today combines high-fidelity unit-commitment, security-constrained dispatch, high-resolution storage state-of-charge tracking, and very-large Monte-Carlo coverage in a single coherent run. Practical studies including this project therefore stitch together complementary tools, with consistent data schemas and time-series alignment as the binding interoperability requirement.
- Importance of security-constrained adequacy. As renewables displace synchronous thermal generation, post-contingency thermal and voltage limits increasingly co-determine adequacy outcomes; treating security as a downstream feasibility check materially under-counts adequacy risk in corridors that are pre-fault feasible but post-fault constrained, Section 6.4 of this report.
- Integration of time-sequential investment and adequacy. The investment-decision sequencing produced by SCTNEP and similar co-optimization frameworks must be carried into the adequacy assessment year-by-year, otherwise the adequacy outlook does not reflect the actual capacity ramp; this argues for a tightly coupled, time-sequential PASA architecture as adopted in Part II.
- Climate-aware long-term assessment. Reanalysis-based weather inputs are not yet routinely supplemented with climate-projection ensembles, leaving long-horizon adequacy outlooks exposed to the long-tail risk of changing renewable resource availability and demand patterns [93]. Incorporating downscaled climate projections into PASA is an active research direction.
- Resource adequacy for sector-coupled and demand-flexible systems. Adequacy frameworks that recognize hydrogen electrolysis, electric vehicle aggregations, and large-scale demand response as adequacy-contributing resources are still in their infancy; treatment in current tools is highly approximate and methodologically inconsistent.
- Standardization and openness of input data. The lack of openly licensed, time-aligned, region-resolved demand and weather datasets for many jurisdictions remains a structural barrier to reproducible PASA studies. Initiatives such as the Open Power System Data project and AEMO's recent open-data releases are promising but incomplete.

The PASA framework adopted in this project set out in Section 7.2 and implemented in Chapters 9-10 is designed to address the most directly relevant of these gaps: explicit chronological storage state-of-charge across all three horizons, security-constrained inputs from Part I, Monte-Carlo coverage for confidence-bounded indices, and a tool stack that combines a high-fidelity production-cost engine for short-term studies with a transportation-flow Monte-Carlo solver for long-horizon adequacy assessment. The gaps in climate-aware projection, sector coupling, and standardized open data are noted as residual risks and are revisited in the planning recommendations of Chapter 11.

9 Time-sequential Modelling Framework for Projected Assessment of System Adequacy

9.1 Modelling Framework and Workflow

Building on the gaps identified in Chapter 8, this section sets out the modelling framework and workflow adopted in this project for the projected assessment of system adequacy. The framework is designed to be implementation-agnostic at the level of methodology that specifies the workflow stages, data flows, modelling features, and assessment outputs without prescribing a single tool and is realized in this project using a combination of industry-standard production-cost simulation, open-source probabilistic resource-adequacy solvers, and co-optimized time-sequential planning models. The structural intent is to preserve the chronological and energy-coupled features of the modern NEM throughout the assessment, and to embed the time-sequential investment pathways established in Part I as a direct input to the adequacy evaluation, so that the resulting reliability indices reflect not only the long-run equilibrium portfolio but also its year-by-year evolution.

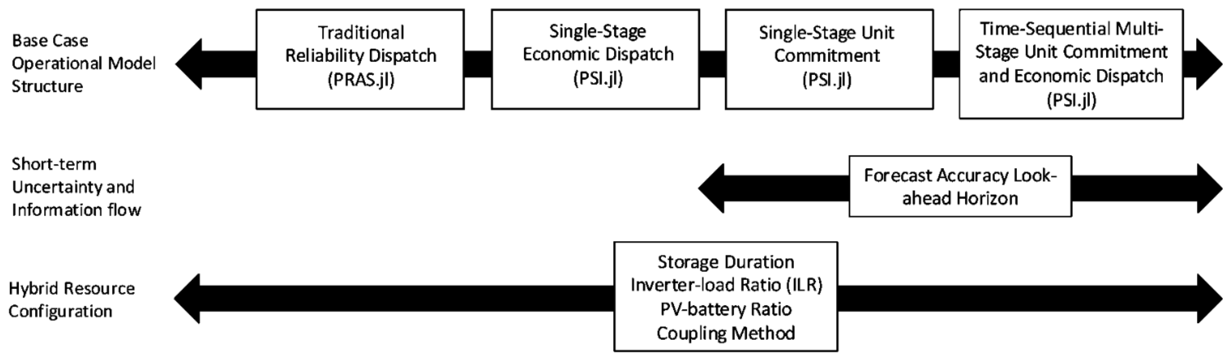


Figure 9.1 Conceptual progression of resource adequacy modelling frameworks, from static reliability dispatch to time-sequential, multi-stage representations incorporating uncertainty and storage behavior. The framework reflects an implementation-agnostic structure and is realized using a combination of industry-standard simulation and optimization tools.

Figure 9.1 illustrates the conceptual progression that underpins this design choice. The leftmost frame represents the legacy deterministic-dispatch and load-duration-curve methodologies with a probabilistic Monte-Carlo wrapper that samples weather, demand, and outage realizations across a time-sequential portfolio evolution that is characterized as early adequacy assessment. While computationally efficient, such representations provide limited insight into prolonged stress events or inter-temporal constraints. Successive frames add chronological dispatch, explicit unit-commitment and economic-dispatch (UC + ED) positioned to address the methodological gaps identified in Section 8.2.2.

9.1.1 Multi-stage workflow

The projected assessment of system adequacy workflow proceeds through five logically sequential stages, each producing artefact that are consumed by the next:

- Stage 1 - Planning-pathway ingestion. The optimal time-sequential investment pathways derived in Part I (Chapter 6): generation additions and retirements, storage commissioning, transmission augmentations, and HVDC interconnector build are imported as year-by-year network states across the 2025–2051 horizon.
- Stage 2 - Time-series construction. Region-resolved, half-hourly chronological time series of demand, wind, solar, and hydro inflows are constructed for a defined set of climate years, supplemented by Monte-Carlo samples of forced-outage realizations and stochastic demand growth.
- Stage 3 – Regional probabilistic resource-adequacy evaluation. A sequential Monte-Carlo probabilistic-adequacy solver (PRAS.jl) is run against the same portfolio and time-series inputs to produce confidence-bounded estimates of LOLP, LOLE, LOLF, LOLD, EUE, and USE for each year and region for up to twenty-year horizon.
- Stage 4 – Full network operability and unit-commitment screening. For the same portfolio along the planning pathway, a sequential UC + ED simulation is performed using PowerSimulations.jl at full sub-hourly resolution to verify operational feasibility, capture renewable curtailment, and establish a reference dispatch against which probabilistic adequacy outputs can be reconciled for identified weeks.
- Stage 5 - Synthesis and reporting. Indices are aggregated across horizons (ST, MT, LT) and scenarios, pressure-point years, and identified weeks across regions, and the results are translated into planning-policy implications.

The workflow's defining feature is the explicit coupling between the planning model in Part I and the adequacy model in Part II. Generation, storage, and transmission infrastructure does not appear in the adequacy assessment as a static long-run portfolio; instead, the assessment is performed year-by-year with the portfolio that the SCTNEP framework actually commits in that year, including the timing of coal retirements, the entry of renewable and storage capacity, and the commissioning of transmission augmentations. The resulting adequacy outputs therefore reflect the realized trajectory of the system, not an idealized end-state, and expose any transitional adequacy gaps that would be invisible to a steady-state analysis.

The probabilistic resource adequacy assessment using PRAS.jl applied to a SNEM system by automated reduction to 15 subregions as shown in Figure 9.2 to match ISP spatial detail. The project builds a consistent modular workflow and a framework as shown in Figure 9.3 from a common codebase using scripts that enable easy analysis of various scenarios, with pre-processing and reproducible capabilities for input time-series data, small- to large-scale Monte-Carlo time-sequential simulations, analyses, and visualization of the PRAS.jl and PowerSimulations.jl post-processing results. All adequacy assessment studies are implemented in iPASA.jl.

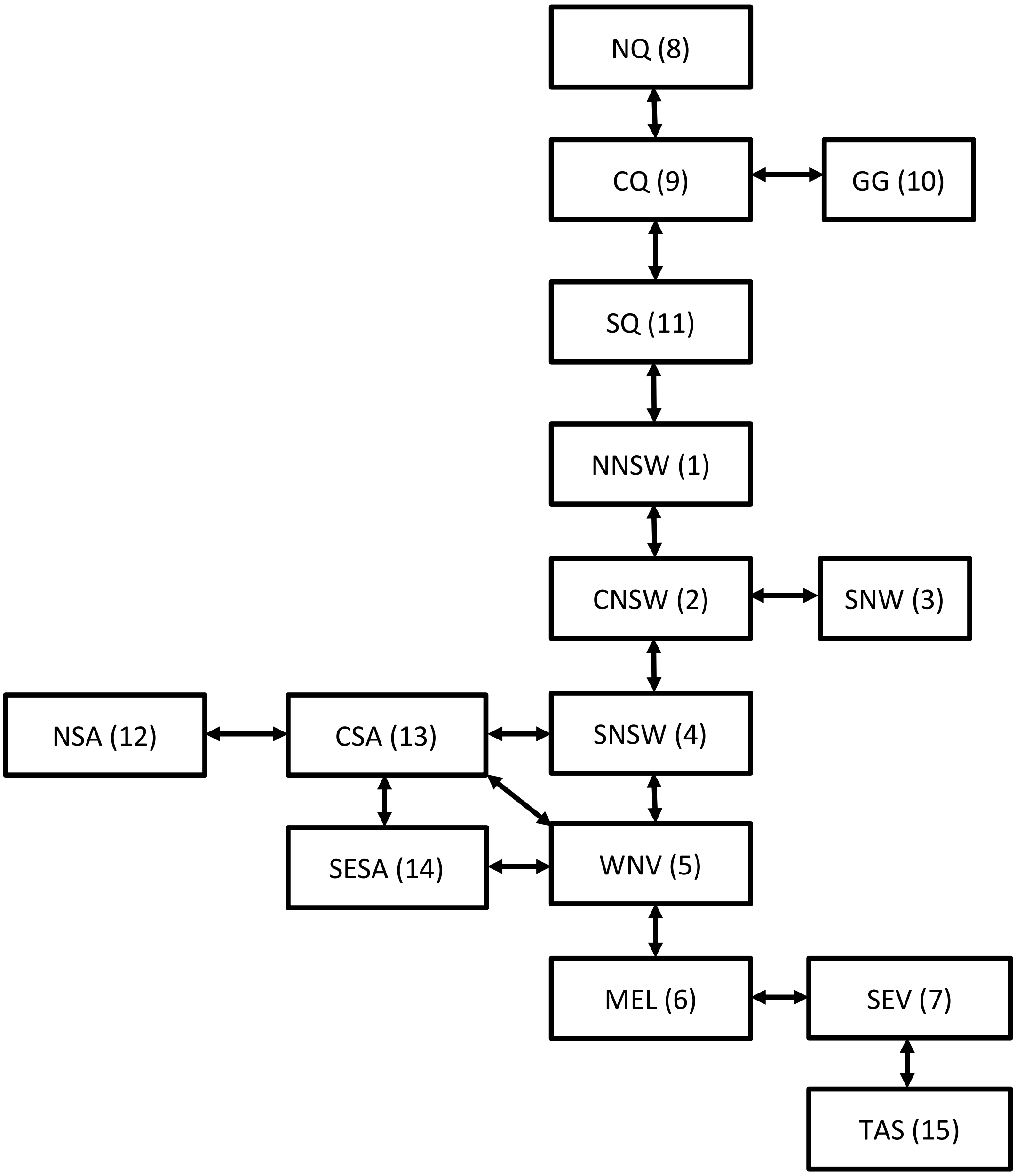


Figure 9.2 Regional representation for PRAS indicating the fifteen regions (area code) automatically modelled along with bi-directional interfaces for probabilistic system adequacy assessment

9.1.1 Modelling framework and assumptions

To define regions (or areas) in SNEM, K-means clustering was applied to each of the four mainland states (Tasmania was treated separately). Clustering was based on the spatial location of bus coordinates, with the results verified against a spatial mapping to the nearest real NEM areas. Adjustments were then performed to align bus locations, generator and storage assets properly mapped to the relevant newly created areas and that each cluster contains sufficient baseline load and generation buses to represent it. The dataset was further augmented with inter-regional transmission capacities that reflect existing and planned network augmentations. The baseline model was constructed and formulated following the analysis described in the Chapter 4 in Part I.

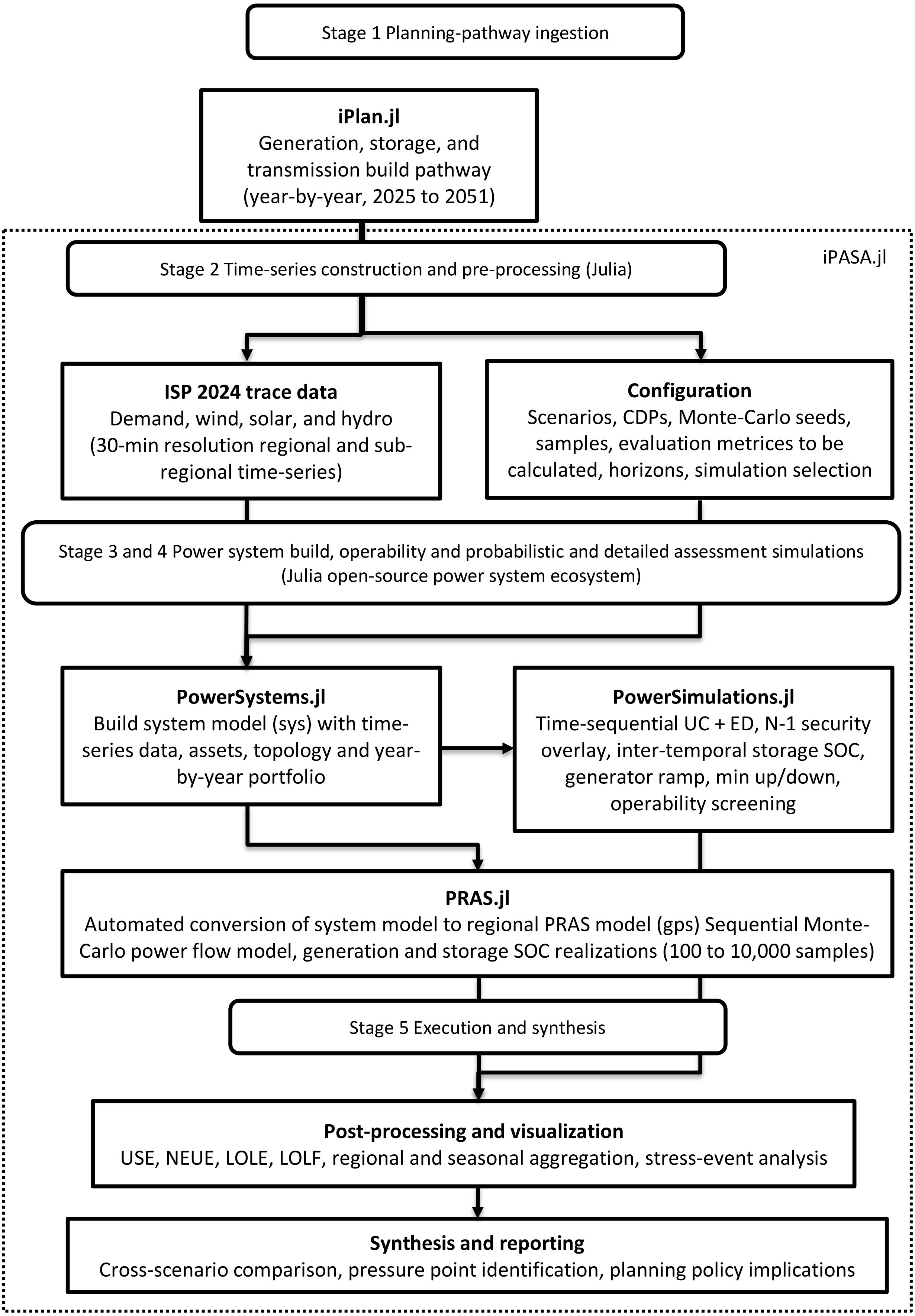


Figure 9.3 iPASA.jl: High-level projected assessment of system adequacy workflow, showing the ingestion of ISP data and iPlan.jl planning pathways, the Julia-based preprocessing pipeline, the build of the system model with PowerSystems.jl, the operability with PowerSimulations.jl, and PRAS, the execution, and post-processing.

This study uses 2024 ISP Trace data at 30-minute resolution. The trace data includes demand for only 12 areas; all five states contain aggregated wind data, and four states (excluding Tasmania) have aggregated solar generation data. Hydro data is available for the Tasmania region. Where ISP trace data is unavailable at the area resolution, the same scaled time series is reused across areas of the same state. For example, the three Victorian areas (WNV, MEL, SEV) share scaled VIC data, and the additional South Australian area (NSA) uses CSA-scaled data. The load, solar, and wind generation time series are assigned based on the corresponding scaling factors. Following AEMO naming conventions, the 15 areas retained in the expanded SNEM dataset are listed below, and the spatial distribution and inter-area interfaces are illustrated in Figure 9.2.

- NSW (1 NNSW, 2 CNSW, 3 SNW, 4 SNSW)
- VIC (5 WNV, 6 MEL, 7 SEV)
- QLD (8 NQ, 9 CQ, 10 GG, 11 SQ)
- SA (12 NSA, 13 CSA, 14 SESA)
- TAS (15 TAS)

Each sub-region is characterized by:

- Temporal demand and generation profiles consistent with the ISP forecasts. Standard pre-processing tools (for example, MinMaxScaler) are applied to identify the time-period that best represents the scaled time-series data for a particular scenario.
- Installed and committed generation capacity by technology type.
- Energy-constrained storage resources (for example, utility-scale batteries).

- Pre-processed time-series inputs for regional demand, wind, and solar at hourly and 30-minute resolution, drawn from the ISP trace data.
  - A scaled hydro time series constructed from the Tasmanian record and applied to the other hydro resources where direct data is not available.
- Scenario scaling applied for the assessment horizons (one year, six years, and twenty years) considered in this study.

The augmented network, including future generation, storage, and load with time-series data, is constructed using the PowerSystems.jl Julia package with the SingleTimeSeries data structure prior to automated export into the regional PRAS model. Note that the sequential UC+ED simulations are performed in PowerSimulations.jl using the system model developed using PowerSystems.jl. The baseline 2025 system and as per plan augmented 2044 network are summarized in Table 9.1.

Table 9.1 Baseline (2025) and Augmented (2044) System Components

Model construction	AC Buses	Lines	Storage (count/GWH)	Hydro (count/GW)	Load (count/GW)	Renewable active/rating (count/GW)	Thermal active power (count/GW)	DCline (count)	Area
Baseline (2025)	2022	1341	48(8.5)	79 (8.82)	912 (34.7)	239 (9.95)	103 (30.19)	3	15
Augmented network (2044)	2042	1371	402(25)	79(8.82)	912(20)	746(69)	Controlled retirement	22	15

For thermal generators, a scaling factor of 0 indicates the generator has expired and has no power, while a factor of 1 means the generator is available at its rated capacity and supplies active power. Powersystems.jl did not implement the future data storage time-series multiplier in the same way; instead, it was incorporated directly into the PRAS storage model by multiplying the storage time-series binary array (0s and 1s). This represents storage availability when started with a multiplier of 1. The closure time for the thermal generators are assumed to be on the 1st of December, with the corresponding year added or treated as expired, as sourced from the ISP data.

Interoperability between the planning model, the PowerSystems.jl system builder, the PowerSimulations.jl operability simulator, and the PRAS.jl adequacy simulator is supported through standard data schemas. The system is built once in PowerSystems.jl and exported to the operability and adequacy models through their respective import interfaces, ensuring that the same asset register, network topology, and time-series inputs are used in both simulation paths. This avoids the inconsistencies that arise when adequacy and operational simulations are built from separate data pipelines.

10 Projected Assessment of System Adequacy Results and Analysis

This chapter presents the results and analysis of the projected assessment of system adequacy for the SNEM under long-term planning pathways. Building on the optimal development pathways derived from the time-sequential SCTNEP framework, the analysis evaluates the ability of generation and storage resources to reliably meet electricity demand. The assessment is conducted pre-planning (baseline) across short-, medium-, and long-term horizons and post-planning long-term horizons with full half-hourly time-series resolution, enabling the capture of inter-temporal dependencies associated with energy-limited storage resources.

10.1 Projected Assessment Horizons, Time Windows, Methodologies, Tools and Purpose

In this project, the projected system adequacy assessment analysis assesses the ability of the evolved generation and storage portfolio to meet demand across short-, medium-, and long-term horizons. All assessments are performed using four complementary evaluation horizons designed to capture short-term (yearly and weekly), medium-term (six-years) including stress-condition, and long-term (twenty-years) reliability characteristics. The details of the adequacy assessment horizons, time windows, methodologies, tools and purposes are summarized in Table 10.1.

Table 10.1 Adequacy assessment horizons, time windows, methodologies and purpose

Horizon	Window	Methodology/Tools	Purpose
Short term	1 year and 1 week	Probabilistic Monte-Carlo (PRAS.jl) and Time-sequential UC+ED (PowerSimulations.jl)	Operational adequacy under realized intra-day variability; storage charge / discharge feasibility; post-fault redispatch headroom, vulnerability to multi-day low-renewable events
Medium term	6 years	Probabilistic Monte-Carlo (PRAS.jl)	Seasonal energy-budget adequacy; storage cycling and energy-limited reliability contribution in normal and stressed condition
Long term	20 years	Probabilistic Monte-Carlo (PRAS.jl)	Trends in adequacy as the generation and storage portfolio evolves along the planning pathway; pressure years identification; scenario seasonal sensitivity of long-term reliability indices

10.2 Baseline Assessment of Projected System Adequacy

This section presents the baseline assessment of projected system adequacy across short-, medium-, and long-term assessment horizons, as defined in Table 10.1, with the analysis limited to the Step Change scenario. The baseline case represents the evolution of load demands, REZs related renewable generation, associated network and storage developments, thermal generator retirements, and committed or in-progress projects, without incorporating any additional candidate augmentation options under consideration. However, the bassline assessment provides strong indications of the augmentation options needed over the planning horizon. Note that NEUE is the expected unserved energy divided by the total energy demand and can be reported as a percentage or a fraction. In this work, NEUE is reported as a dimensionless fraction.

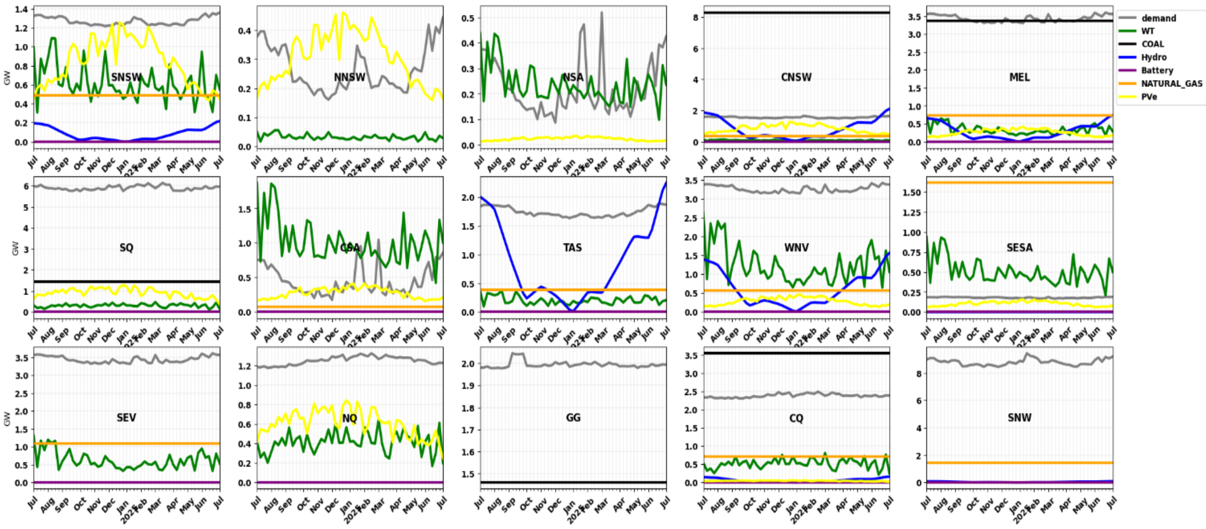


Figure 10.1 Average weekly load, generation and storage for each SNEM area from 2025 to 2026

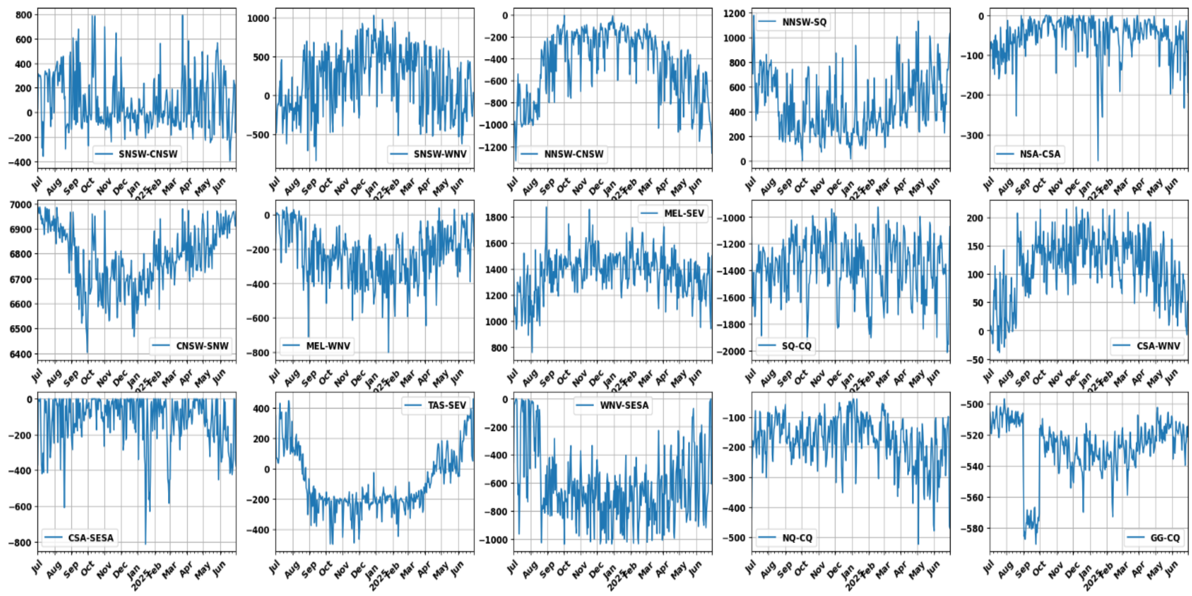


Figure 10.2 Daily average Load flow in the inter-area interfaces from 2025 to 2026

10.2.1 Short-term adequacy assessment

The short-term adequacy assessment evaluates resource adequacy over a single chronological projection year, representing near-term operational conditions following committed network, generation, and storage developments. The assessment reflects the baseline system configuration for the period 2025 to 2026 and considers only existing and committed infrastructure without additional candidate augmentations. Figure 10.1 presents the average weekly load, generation, and storage profiles across all assessed SNEM areas and Figure 10.2 presents the daily average power flow in the inter-area interfaces for the assessed horizon. The modelling framework includes chronological Monte Carlo simulations over a full operational year with a sample size of 1000, enabling probabilistic evaluation of adequacy outcomes under varying operational conditions and renewable variability.

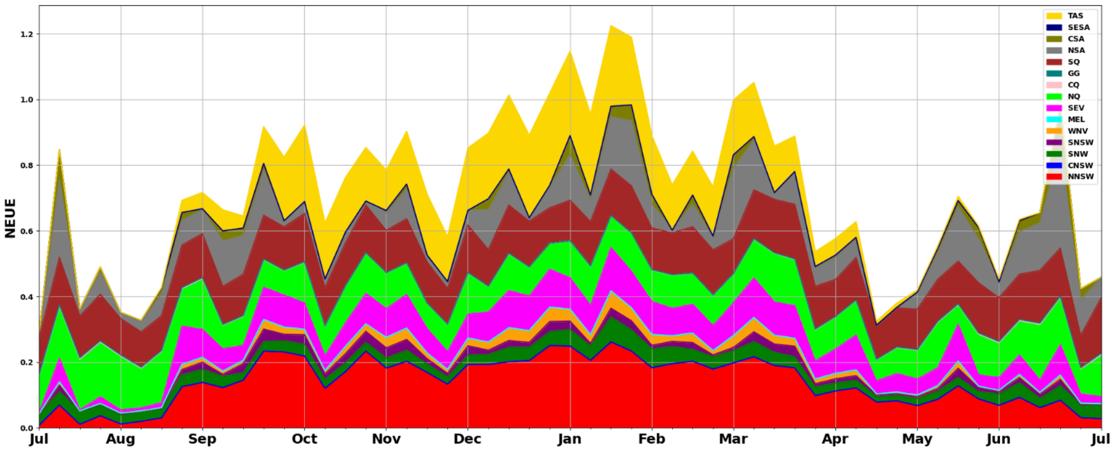


Figure 10.3 Weekly NEUE metric for each NEM area in 2025 to 2026

The simulations are performed at a half-hourly temporal resolution using normalized time-series profiles, providing a comparatively higher-fidelity representation of chronological operational behavior than the reduced-resolution scenarios considered in other planning horizons. Figure 10.3 illustrates the resulting weekly NEUE metrics across all areas for the short-term scenario. The results indicate seasonal variability in adequacy risk, with elevated NEUE observed during periods of increased demand and renewable variability. The regional contributions highlight the spatial distribution of adequacy stress across the interconnected system and provide insight into the evolving adequacy performance of the baseline network under near-term operating conditions.

The comparatively elevated NEUE values observed across several periods indicate that the baseline system, comprising only existing and committed developments, may face increasing adequacy challenges under projected operating conditions. These results highlight the potential need for additional planned augmentations to maintain acceptable reliability and adequacy standards as the system continues to transition toward high renewable penetration.

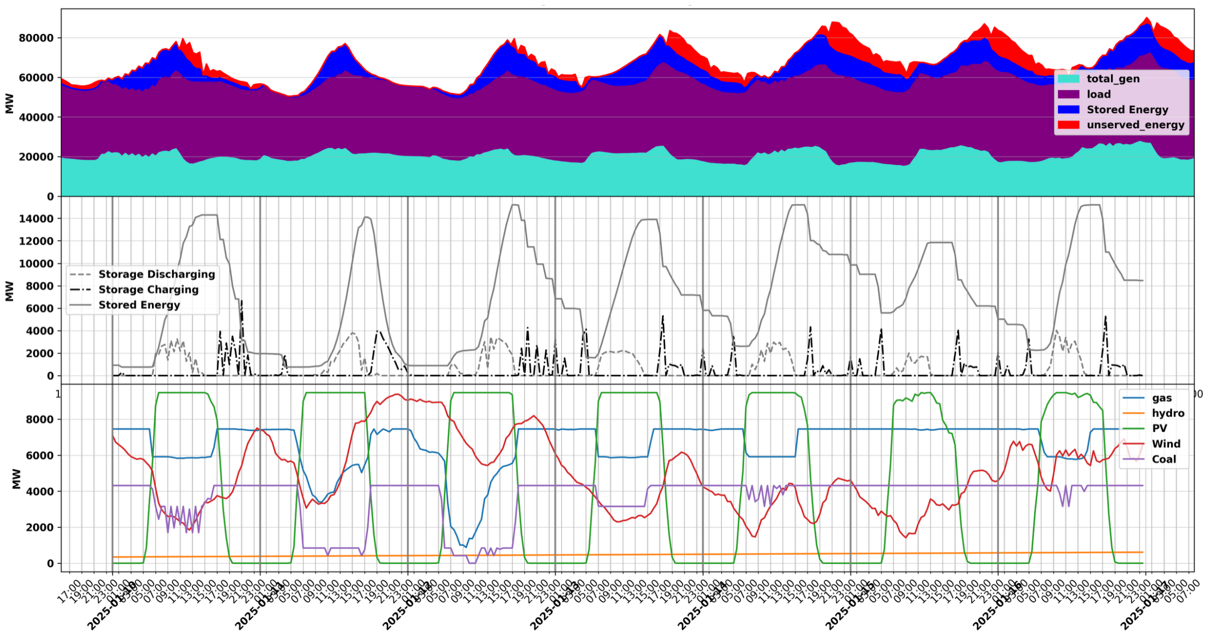


Figure 10.4 Time-sequential simulation incorporating a rolling unit commitment (UC) and economic dispatch (ED) framework at half-hourly resolution over a 1-week horizon (Load (MW), generation (MW), storage (MWh))

To further illustrate the operational behaviour underlying these adequacy outcomes, Figure 10.4 presents an example of a chronological time-sequential simulation incorporating a rolling UC and ED framework at half-hourly resolution over a 1-week horizon. The simulation captures detailed operational and inter-temporal constraints, including generator commitment states, ramping limitations, minimum up and down times, storage charging and discharging dynamics, and energy state transitions across time periods. The results demonstrate the interaction between load variability, renewable generation fluctuations, storage operation, thermal generation commitment, and periods of unserved energy. They further highlight the growing dependence on storage and flexible dispatchable resources during periods of low renewable output and high demand, while illustrating the challenges of maintaining adequacy under renewable variability.

10.2.2 Medium-term adequacy assessment

The medium-term adequacy assessment considers a 6-year planning horizon spanning 2025 to 2031, representing a near-term critical transitional phase. As a result, the medium-term horizon captures a system undergoing substantial structural transformation, where operational adequacy increasingly depends on the successful coordination and timing of generation, storage, and REZ associated and committed network extensions. It provides improved visibility of emerging reliability risks over the medium-term assessment horizon. Note that baseline system doesn't include candidate option augmentations and represent a pre-planning stage assessment highlighting the need of network augmentations required to address system adequacy gaps.

Figure 10.5 presents the average monthly load, generation, and storage profiles for the medium-term scenario across the assessed 6-year horizon. The assessment is performed using a year-by-year chronological Monte Carlo simulation framework with a sampling size of 100, enabling the progressive evolution of the system topology, generation fleet composition, storage capability, and demand characteristics to be represented explicitly across the study horizon. It is evident that several regions, including NSA, CSA, GG, SNW, SQ, WNV, and SEV, exhibit strong dependence on inter-area power transfers due to insufficient local generation and storage capacity. In contrast, regions such as SNSW, NNSW, CNSW, SESA, and CQ demonstrate surplus generation and storage capacity relative to their local demand over the assessed six-year horizon. These observations highlight the importance of considering additional inter-regional transmission augmentations and transfer capability enhancements within the candidate planning options. Furthermore, regions including MEL, TAS, and NQ appear to operate with comparatively marginal supply-demand balances during certain periods of the year, indicating increasing sensitivity to renewable variability, generator availability, and transmission support. This suggests that extended long-term adequacy projections may be beneficial to further assess emerging reliability trends.

The seasonal NEUE metrics for the medium-term scenario across all SNEM areas are presented in Figure 10.6. Elevated seasonal NEUE periods indicate operating conditions under which renewable generation variability, reduced thermal generator availability, transmission limitations, and insufficient firming capability may challenge system adequacy, particularly during peak demand stressed conditions or extended periods of low renewable resource availability. The results highlight the increasing importance of timely transmission reinforcements, network augmentations, and additional flexible firming resources to maintain acceptable reliability and adequacy standards throughout the transition period.

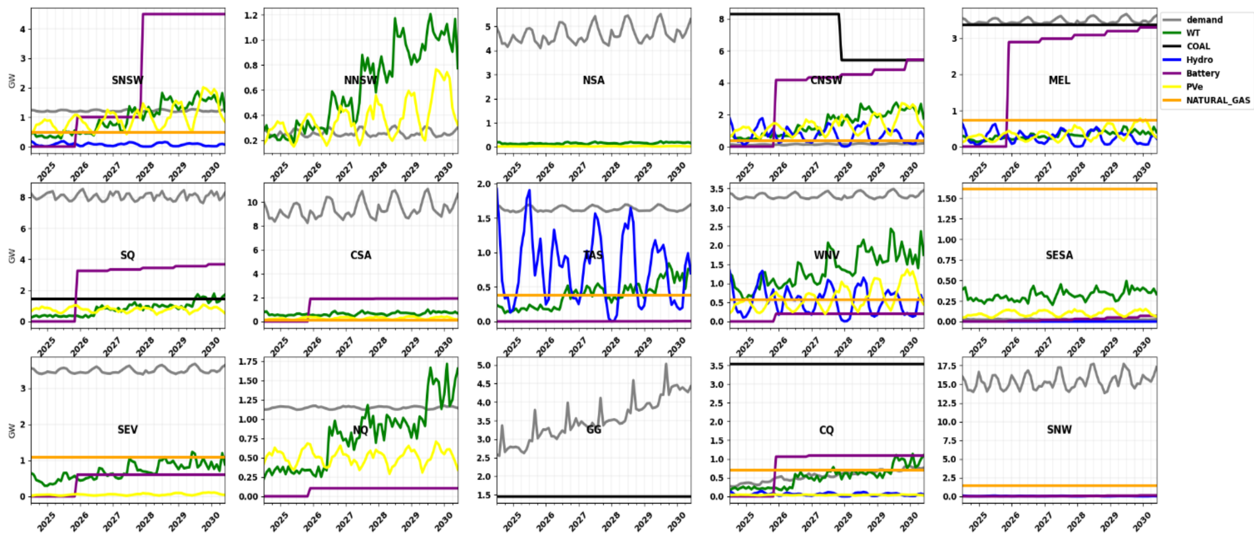


Figure 10.5 Average monthly load, generation and storage for each NEM area from 2025 to 2031

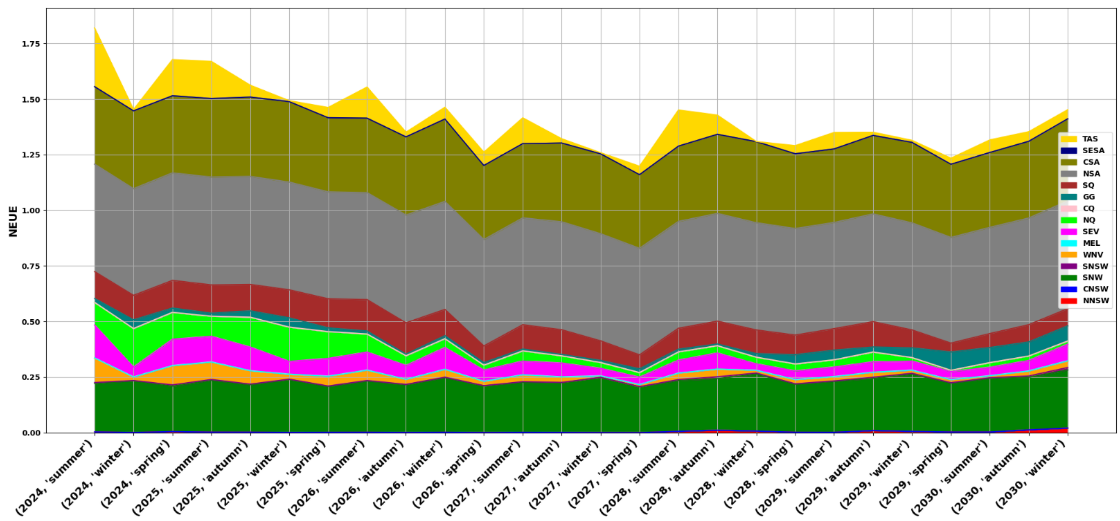


Figure 10.6 Seasonal NEUE metrics across all NEM areas from 2025 to 2031

10.2.3 Long-term adequacy assessment

The long-term adequacy assessment evaluates the evolution of system reliability over a 20-year planning horizon from 2025 to 2045. This assessment represents the most comprehensive adequacy outlook considered in this study and captures the cumulative impacts of large-scale structural transformation of the SNEM. The long-term horizon is particularly important for assessing whether the evolving power system can maintain acceptable reliability and adequacy standards under increasingly high penetrations of renewable energy resources. Unlike short- and medium-term assessments, the long-term analysis captures the projected transition toward a highly renewable-dominated system in which adequacy is increasingly influenced by renewable resource diversity, storage duration and utilization, transmission transfer capability, operational flexibility, and the temporal coordination of generation and network developments. Figure 10.7 presents the average yearly load, generation, and storage profiles for the long-term assessment. The results illustrate the transition from a predominantly thermal-based generation mix toward a renewable-dominated system supported by large-scale storage and inter-regional transmission.

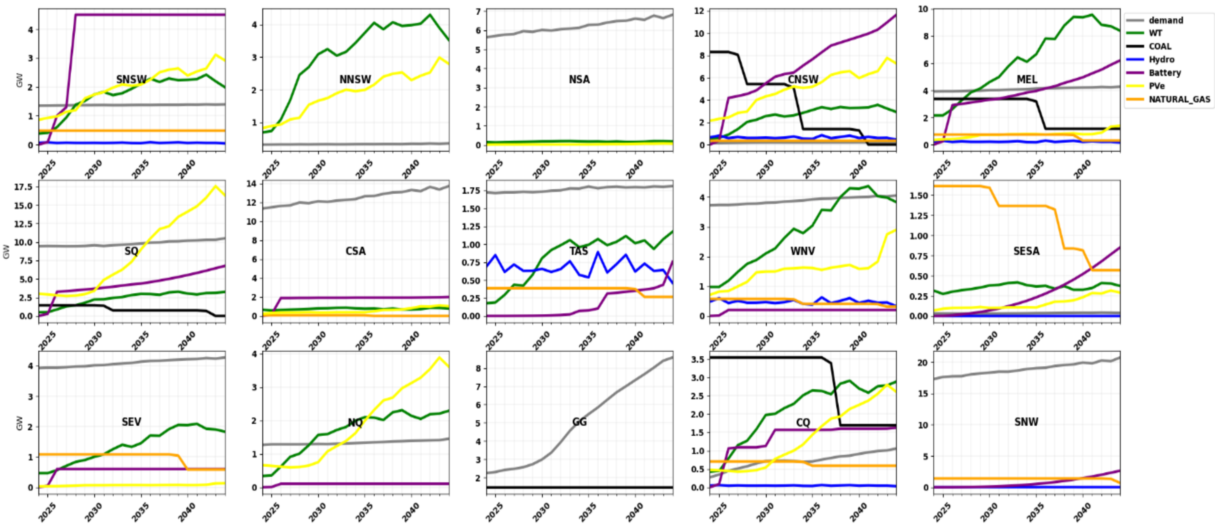


Figure 10.7 Average monthly load, generation and storage for each NEM area from 2025 to 2045

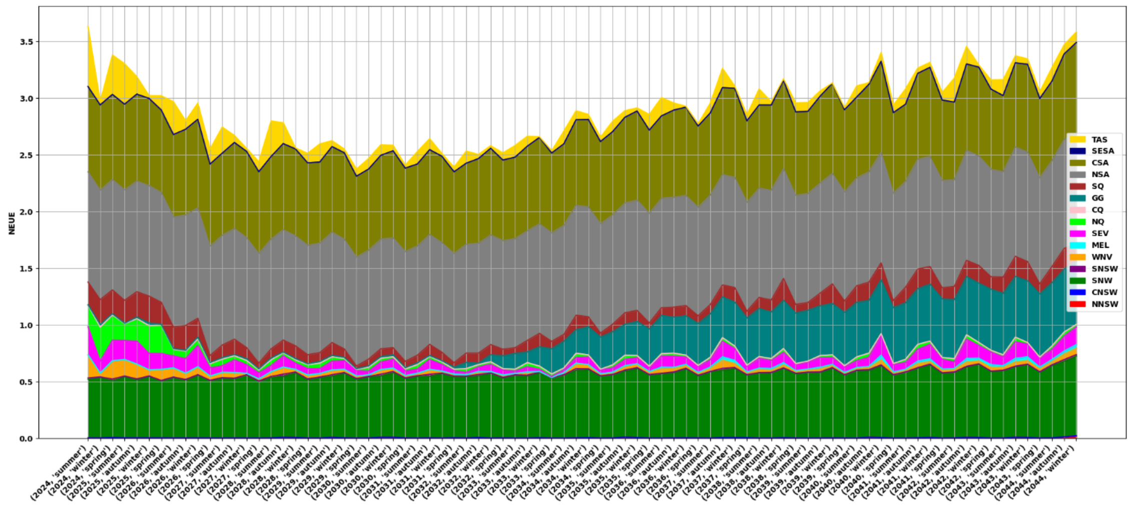


Figure 10.8 Seasonal NEUE metrics across all NEM areas from 2025 to 2045

The results endorsee the medium-term assessment as well as provide clear projections around NQ, MEL and TAS area. In MEL, significant storage and wind generation successfully balance the load demand. Likewise, in NQ, significant increase in wind and PV generation is expected to resolve the adequacy risks. However, TAS area, which showed marginal mismatch shows consistently higher mismatch projections, which indicate the network augmentation options such as Marinus Link. Overall, the generation portfolio evolves significantly as coal-fired generation progressively retires and is replaced by utility-scale wind, solar, storage and transmission-supported REZs.

The chronological seasonal NEUE metrics for each assessed SNEM area is presented in Figure 10.8. The results indicate increasing seasonal and area-wise divergence in adequacy outcomes as the system transitions toward higher penetrations of renewable energy. Periods of elevated NEUE are generally associated with combinations of low renewable resource availability, high demand conditions, transmission transfer limitations, reduced thermal fleet availability, and storage energy limitations during prolonged renewable drought events. Consistent with the medium-term assessment, prominent areas such as SNW, NSA, and CSA show consistently higher values of unserved energy whereas, GG shows increasing trend over the horizon. These results highlight the importance of timely and coordinated delivery of planned network augmentations.

10.2.4 Inter-area interface capacity utilization

In this subsection, adequacy outcomes are explained, in this SNEM context, by the way the inter-area transmission corridors are used over the planning horizon. This section reports the hourly utilization of the 16 modelled inter-area interfaces over the 2025 to 2045 horizon. Utilization is defined as the absolute forward flow divided by the prevailing thermal limit on each interface, so that a value of unity denotes a binding (congested) interval. Statistics are reported overall and within the morning peak (06:00 to 10:00) and evening peak (17:00 to 21:00) windows, and the share of hours at or above 95 % utilization is reported as a direct measure of binding exposure.

Table 10.2 Inter-area interface capacity utilization summary (2025 to 2045). Utilization expressed as a percentage of the prevailing thermal limit on the forward direction

Interface	Mean util.	Morning peak	Evening peak	Hours at ≥ 95 %	2024 mean	2044 mean	Trajectory classification
CNSW-SNW	99.0 %	99.5 %	99.6 %	96.3 %	100.0 %	95.3 %	Persistently binding
CSA-SESA	98.6 %	99.3 %	99.8 %	97.0 %	100.0 %	92.7 %	Persistently binding
CSA-WNV	97.9 %	98.9 %	99.7 %	97.4 %	99.5 %	90.6 %	Persistently binding
GG-CQ	53.9 %	52.7 %	56.7 %	33.3 %	0.6 %	99.7 %	Rising to binding (binds from 2034)
SQ-CQ	28.0 %	9.3 %	46.3 %	1.8 %	51.0 %	22.7 %	Declining
WNV-SESA	23.2 %	21.2 %	28.7 %	3.9 %	4.5 %	60.1 %	Rising (binds from 2041)
NNSW-SQ	22.6 %	6.0 %	43.9 %	6.3 %	18.2 %	26.1 %	Rising (evening peak)
NNSW-CNSW	14.9 %	7.8 %	22.7 %	7.8 %	8.9 %	30.1 %	Rising
SNSW-WNV	12.5 %	6.6 %	18.3 %	6.8 %	2.2 %	29.1 %	Rising
SNSW-CNSW	12.3 %	5.2 %	18.4 %	2.0 %	2.4 %	30.4 %	Rising
TAS-SEV	9.1 %	7.6 %	12.0 %	1.2 %	3.4 %	10.8 %	Moderate
MEL-TAS	5.4 %	6.3 %	5.3 %	0.0 %	17.0 %	6.0 %	Declining
NSA-CSA	4.7 %	3.9 %	0.6 %	1.4 %	0.0 %	10.9 %	Persistently light
NQ-CQ	3.9 %	1.5 %	6.7 %	0.0 %	7.5 %	9.1 %	Persistently light
MEL-SEV	1.7 %	1.7 %	2.0 %	0.0 %	3.5 %	2.2 %	Persistently light
MEL-WNV	1.0 %	0.5 %	1.5 %	0.0 %	1.5 %	2.0 %	Persistently light

Three interfaces (CNSW-SNW, CSA-WNV, and CSA-SESA) exhibit persistent saturation throughout the horizon, with mean utilization in the 98 to 99 % range and binding-hour fractions of 96 to 97 %. These interfaces are continuously congested from the first year of the simulation and remain so even at horizon end despite a modest decline from 100 % to 91 to 95 % mean utilization as upstream supply diversifies. The persistent saturation directly explains the residual elevated NEUE observed in CSA and SNW, highlighting that the import capability into these areas is binding throughout the assessed horizon as indicated in Table 10.2.

The GG to CQ interface exhibits the most striking trajectory in Table 10.2. Its mean utilization rises from 0.6 % in 2024 to 99.7 % in 2044, with the binding-hour fraction reaching 33 % over the horizon and the interface annual mean exceeding 50 % from 2034 onwards. This pattern is consistent with the Queensland coal-retirement trajectory described in Section 10.2.3 and confirms that GG becomes a structurally importing area in the second half of the horizon as its local thermal fleet retires. The WNV to SESA interface exhibits a similar but later transition, with mean utilization rising from 4.5 % in 2024 to 60.1 % in 2044 and crossing the 50 % threshold from 2041, reflecting the build-out of the Mid-North South Australian REZ and the corresponding export uplift.

Four interfaces (NSA-CSA, NQ-CQ, MEL-SEV, and MEL-WNV) remain persistently light (mean utilization below 10 % throughout). Of these, the NSA to CSA interface is informative: NSA exhibits the largest baseline adequacy gap in the SNEM (Section 10.2.3) but the interface to CSA is essentially unused, confirming that the binding adequacy mechanism in NSA is internal sufficiency rather than import capability, and that the optimal solution must place new generation and storage within NSA rather than expand the NSA to CSA corridor. The light loading of the MEL-WNV, MEL-SEV, and NQ-CQ corridors confirms that these areas carry sufficient internal supply across the horizon and do not constitute a planning bottleneck.

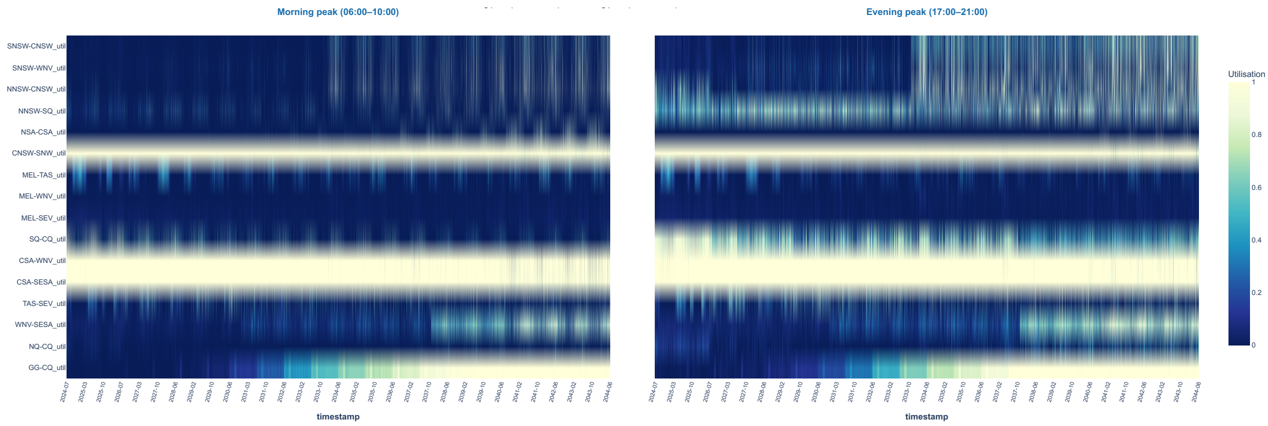


Figure 10.9 Hourly utilisation of the 16 inter-area transmission interfaces during the morning peak (06:00 to 10:00, left) and the evening peak (17:00 to 21:00, right) across the 2025 to 2045 horizon. Darker shading indicates higher utilisation; navy denotes binding (greater than or equal to 95 %)

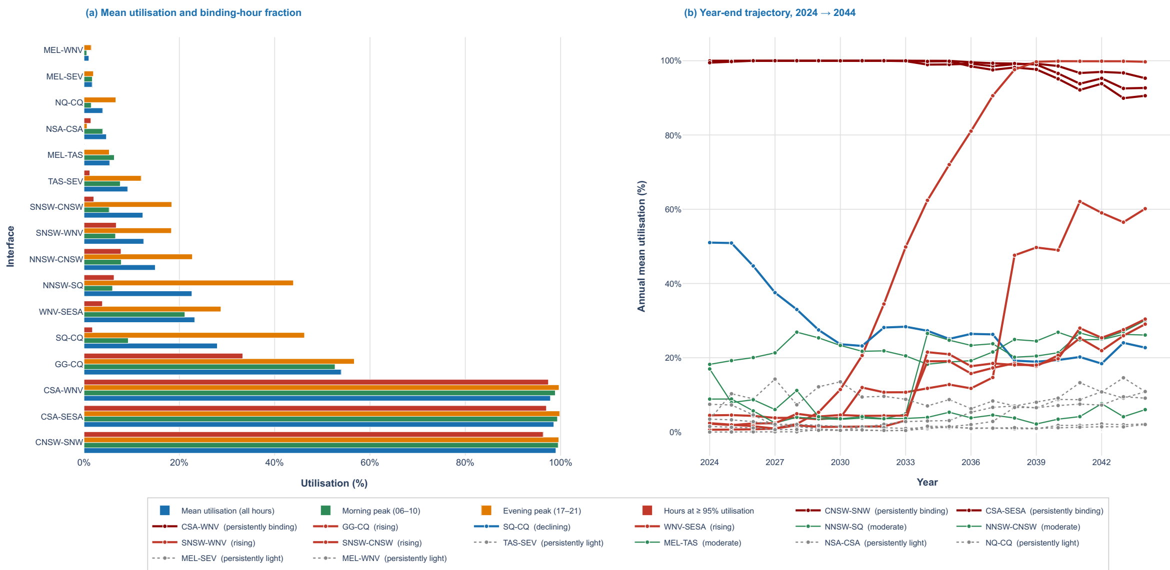


Figure 10.10 (a) Summary of interface utilisation by interface, showing overall mean, morning-peak mean, evening-peak mean, and the percentage of hours at or above 95 % utilisation. (b) Year-end utilisation trajectories (2025 to 2045), colour-coded by classification (persistently binding, rising, declining, persistently light, moderate)

Figure 10.9 presents the morning-peak and evening-peak utilization heatmap for the 16 interfaces across the entire horizon, and Figure 10.10 presents the summary bar chart and year-end trajectories used to derive the classifications in Table 10.2. A clear time-of-day signature is observed on most corridors. The evening peak typically carries materially higher utilization than the morning peak, reflecting the loss of solar generation while electricity demand remains elevated. SQ to CQ (evening 46.3 % versus morning 9.3 %), NNSW to SQ (43.9 % versus 6.0 %), and NNSW to CNSW (22.7 % versus 7.8 %) exhibit the strongest morning-to-evening uplift. The NSA to CSA interface is the only corridor exhibiting the reverse pattern (morning 3.9 % versus evening 0.6 %), which is consistent with the South Australian renewable-export pattern peaking around midday and falling to zero in the evening.

The SQ to CQ, MEL to TAS, CNSW to SNW, CSA to WNV, and CSA to SESA interfaces all exhibit a declining utilization trajectory across the horizon. In each case, the decline is attributable to one of two mechanisms: a downstream area developing sufficient internal supply to reduce import demand (SQ to CQ, MEL to TAS), or upstream supply diversifying so that flows shift to alternative corridors (CSA to SESA, CSA to WNV, CNSW to SNW). In all three of these latter cases the decline is small in absolute terms (less than 9 pp) and the interfaces remain saturated through the horizon.

10.3 Evaluation of Projected Assessment of System Adequacy for the Optimal Development Paths

This section evaluates the long-term projected system adequacy associated with the optimal development pathways identified by the time-sequential SCTNEP outcomes under the Step Change, Progressive Change, and Green Energy Exports scenarios best representations. The evaluation proceeds in three steps. The pre-planning baseline NEUE establishes where adequacy stress lies under the existing network. The inter-area interface limits enabled by each SCTNEP representation are tabulated to expose the transmission-side mechanism through which adequacy is improved. The post-planning NEUE variation against the baseline then quantifies the adequacy improvement delivered by each representation.

10.3.1 NEUE assessment

Figure 10.11 reproduces the area-and-season NEUE distribution for the baseline NEM network across the 2025 to 2045 horizon. The baseline NEUE is dominated by three areas (NSA, CSA, and SNW) with values in the 0.6 to 0.9 range across the great majority of seasons and the entire horizon. TAS, SEV, WNV, NQ and CQ areas are structurally low. GG and SQ exhibit an emerging adequacy trend from the late 2030s as Queensland coal retirements accumulate. The seasonal signature (summer and winter values systematically higher than autumn and spring) confirms that the binding mechanism is sustained-energy shortfall. Table 10.3 lists the forward inter-area interface limits enabled by the best, worst, and typical representations of the SCTNEP optimal pathway, alongside the baseline limits.

Table 10.3 Forward inter-area interface limits (MW) for baseline and SCTNEP best, worst, and typical representations

From	To	Base (MW)	Best (MW)	Worst (MW)	Typical (MW)
SNSW	CNSW	2,861	6,861	6,861	6,861
SNSW	WNV	2,029	6,029	6,029	6,029
NNSW	CNSW	1,474	8,474	17,474	11,474
NNSW	SQ	1,989	3,989	9,089	3,989
NSA	CSA	1,442	1,442	1,442	1,442
CNSW	SNW	6,986	9,386	9,386	9,386
MEL	TAS	1,500	1,500	1,500	1,500
MEL	WNV	15,823	21,823	23,823	21,823
MEL	SEV	13,238	13,238	13,238	13,238
SQ	GG	n/a	180	n/a	n/a
SQ	CQ	4,123	12,043	12,223	12,223
CSA	WNV	220	220	220	220
CSA	SESA	1,745	3,745	3,745	3,745
TAS	SEV	509	509	509	509
WNV	SESA	1,038	2,038	2,038	2,038
NQ	CQ	2,131	7,331	10,331	2,131
GG	CQ	2,384	2,417	3,384	3,384

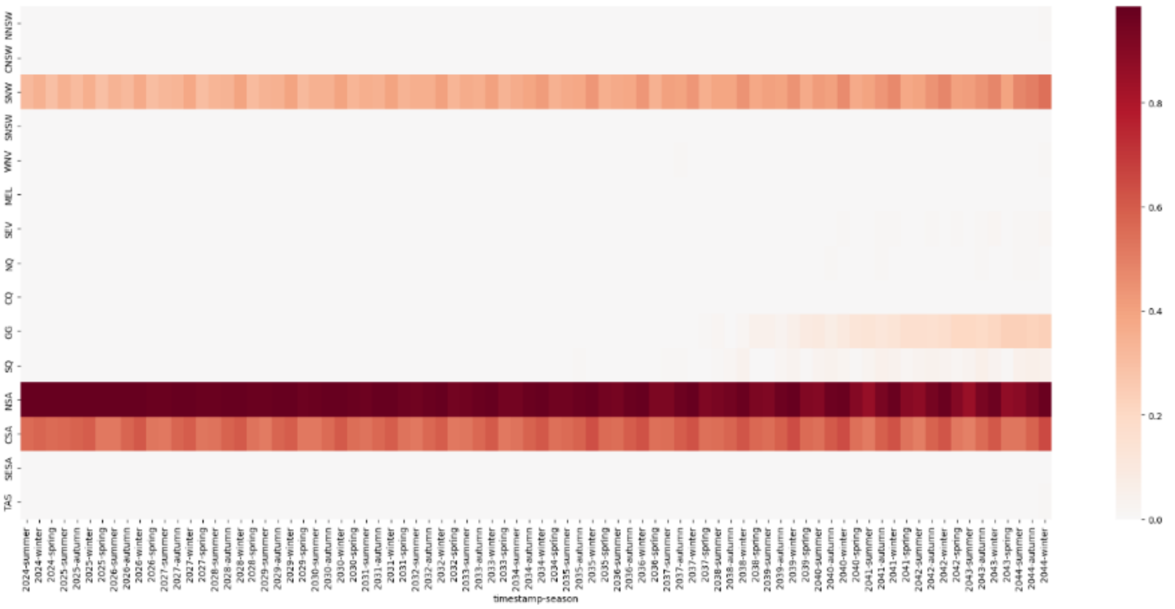


Figure 10.11 Baseline (pre-planning) NEUE by area and season across the 2025 to 2045 horizon. Darker shading indicates higher NEUE

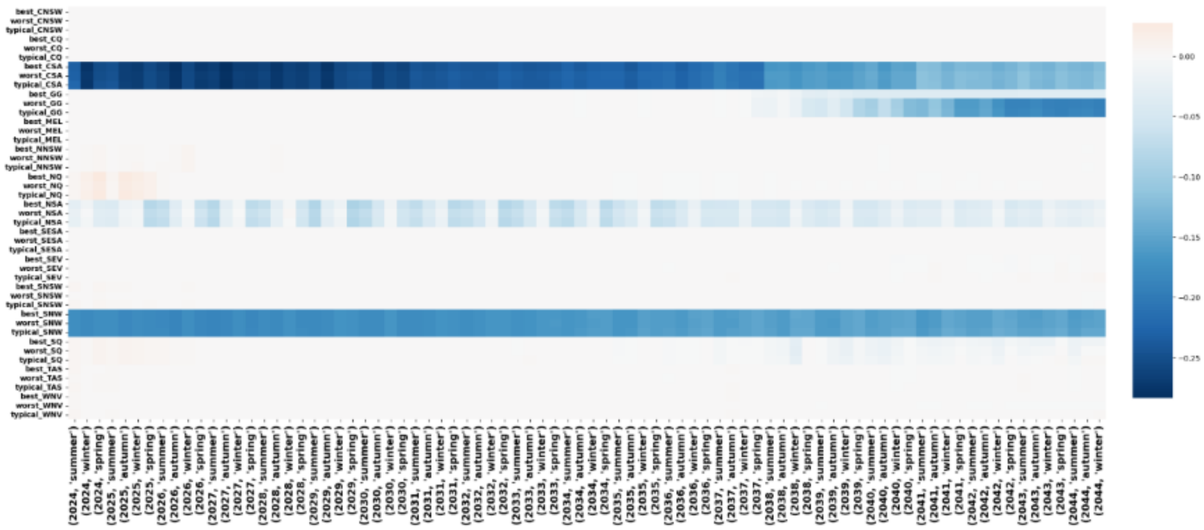


Figure 10.12 Post-planning variation in NEUE relative to baseline for the best, worst, and typical SCTNEP representations of the optimal development pathway. Blue (negative) values denote adequacy improvement

The uplifts are concentrated on a small number of binding corridors (NNSW to CNSW, CNSW to SNW, SNSW to CNSW, SQ to CQ, and MEL to WNV). A small number of interfaces (NSA to CSA, MEL to TAS, MEL to SEV, CSA to WNV, TAS to SEV) remain at their baseline values, indicating that the binding adequacy mechanism in the associated areas is internal sufficiency rather than import capability. The three representations differ less from each other than any of them differs from the baseline, with the worst representation typically carrying the largest single-interface uplift.

Figure 10.12 presents the post-planning variation in NEUE relative to the baseline. The strongest improvements occur in CSA and SNW (0.20 to 0.28 NEUE reduction across the horizon), with smaller improvements (0.03 to 0.10) in NSA, NNSW, and GG. No area or season exhibits adequacy degradation under any representation, confirming that the optimal pathway is Pareto-improving with respect to area-level adequacy. The three representations converge in the severe-gap areas and diverge slightly in the modest-gap areas, consistent with the cost-convergence observation in Section 6.2.1.

10.3.2 LOLH and LOLE assessment

NEUE captures the energy magnitude of adequacy risk but not the frequency or duration of shortfall events. To complement the energy-based view of Sections 10.3.1, this section reports LOLH and LOLE for each area, evaluated on the same 2025 to 2045 horizon under the baseline and the three SCTNEP representations. In accordance with the NEM operational experience and AEMO ESOO sensitivities, the reference value for the NEM Reliability Standard (0.0006 % USE per region per financial year) corresponds approximately to LOLH of three hours per year.

Table 10.4 LOLH (hours per year) and LOLE (days per year) by SNEM area under the baseline and the SCTNEP best, worst, and typical representations

Region	LOLH				LOLE			
	Base	Best	Worst	Typical	Base	Best	Worst	Typical
SNSW	0.09	0.09	0.14	0.25	0.01	0.01	0.02	0.03
NNSW	0.07	0.07	0.18	0.18	0.01	0.01	0.02	0.02
NSA	85.79	25.74	21.34	17.07	10.72	3.22	2.67	2.13
CNSW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MEL	0.06	0.06	0.06	0.07	0.01	0.01	0.01	0.01
SQ	2.94	0.59	2.43	3.01	0.37	0.07	0.30	0.38
CSA	80.80	20.20	17.43	13.93	10.10	2.53	2.18	1.74
TAS	0.31	0.31	0.39	0.48	0.04	0.04	0.05	0.06
WNV	0.26	0.26	0.25	0.43	0.03	0.03	0.03	0.05
SESA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SEV	0.51	0.51	0.54	0.70	0.06	0.06	0.07	0.09
NQ	0.72	0.36	0.95	1.13	0.09	0.05	0.12	0.14
GG	26.98	5.40	5.55	5.79	3.37	0.68	0.69	0.72
CQ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SNW	85.66	21.42	18.95	15.16	10.71	2.68	2.37	1.90

The LOLH and LOLE results confirm the NEUE findings and add a frequency-and-duration interpretation. Three observations follow.

- The dominant adequacy stress is concentrated in NSA, CSA, and SNW, with baseline LOLH values in the 80 to 86 hours per year range (corresponding to LOLE of approximately 10 days per year). These values significantly exceed the NEM reliability reference (three hours per year LOLH, or approximately 0.4 days per year LOLE) and confirm that the baseline network is structurally inadequate in these three areas.
- The SCTNEP best representation reduces LOLH by 70 to 90 % in NSA, CSA, and SNW (from 80 to 86 hours per year to 17 to 26 hours per year) and reduces GG LOLH by 80 % (from 27 to approximately 5 hours per year). The worst and typical representations deliver further incremental improvement, particularly in NSA and CSA, where they reduce LOLH to the 14 to 21 hours per year range. SQ moves from 2.9 hours per year LOLH at baseline to 0.59 hours per year in the best representation, achieving compliance with the NEM reliability reference. NQ achieves a 50 % improvement in the best representation and remains within the NEM reliability reference.
- Five areas (SNSW, NNSW, MEL, CNSW, SESA, CQ) already exhibit LOLH values well below the NEM reference under the baseline, with LOLE of 0.01 to 0.03 days per year. These areas exhibit

no measurable adequacy stress under any of the three representations. The corresponding LOLH values remain essentially unchanged, confirming the Pareto-improving character of the SCTNEP plan with respect to area-level adequacy.

The residual elevated LOLH in NSA, CSA, SNW, and GG after planning indicates that the SCTNEP best representation, while delivering substantial improvement, does not by itself close the adequacy gap in these areas to the NEM reliability reference. The implications for subsequent planning iterations are discussed in Section 10.6.

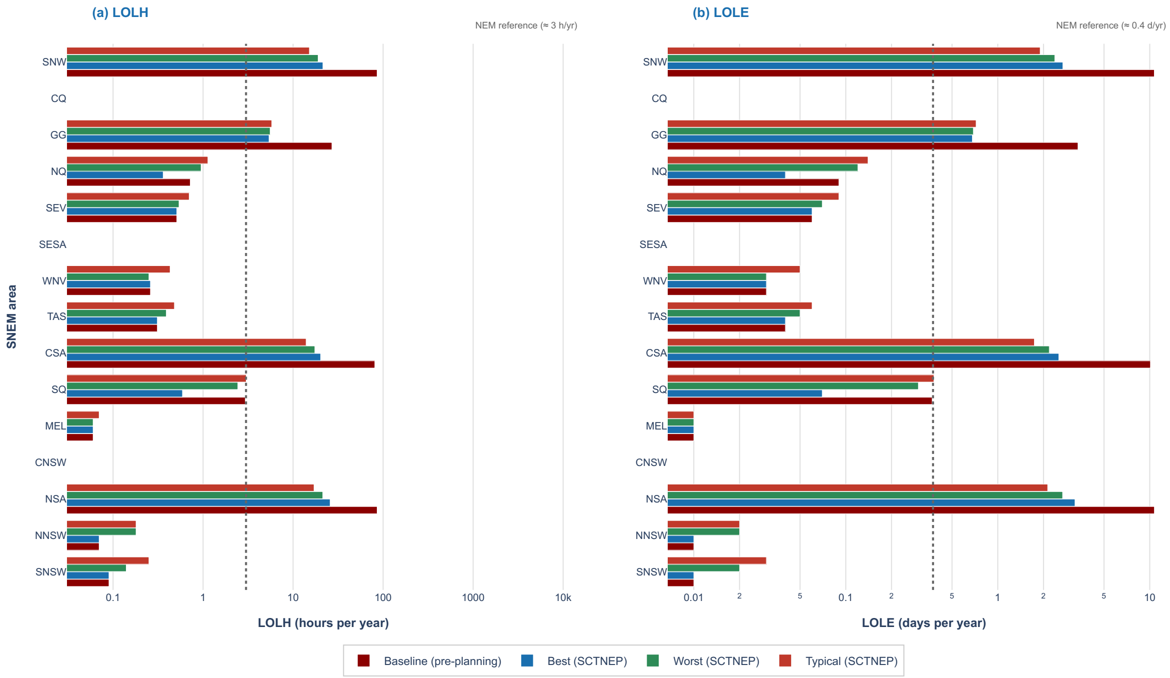


Figure 10.13 LOLH (hours per year, log scale) and LOLE (days per year, log scale) by SNEM area under baseline and SCTNEP best, worst, and typical representations. Dotted vertical lines indicate the NEM reliability reference (LOLH ≈ 3 h/yr, LOLE ≈ 0.4 d/yr)

10.3.3 Inter-area interface capacity utilisation assessment

This subsection reports the hourly utilisation of the 16 modelled inter-area interfaces over the 2025-to 2045 horizon. Utilisation is defined as the absolute forward flow divided by the prevailing thermal limit on each interface, so that a value of unity denotes a binding (congested) interval. Statistics are reported under the baseline (pre-planning) network and under each of the SCTNEP best, worst, and typical representations of the optimal development pathway, so that the transmission-side relief delivered by the planning solution can be inspected directly.

Several patterns are evident in Table 10.5. The persistently saturated corridors identified in the baseline analysis are treated differently in the optimal solution. CNSW to SNW (99.0 % to 78.0 % under the best representation) and CSA to SESA (98.6 % to 52.0 %) are materially relieved by the planned uplifts. The CSA to WNV corridor, by contrast, remains essentially saturated (97.9 % to 96.5 %) because the SCTNEP candidate set does not contain a CSA to WNV augmentation, confirming that this corridor is a candidate for inclusion in the next planning iteration. The northern New South Wales corridors (NNSW to CNSW, SNSW to CNSW, SNSW to WNV) exhibit the largest relative relief (54 % to 77 % reduction in mean utilisation).

Table 10.5 Inter-area interface capacity utilisation (mean across the 2024-07 to 2044-06 horizon, % of prevailing thermal limit) under baseline and SCTNEP best, worst and typical representations

Interface	Base	Best	Worst	Typical	Reduction (best vs base)	Interpretation
CNSW-SNW	99.0 %	78.0 %	76.0 %	77.5 %	21.2 %	Persistently binding, partially relieved
CSA-SESA	98.6 %	52.0 %	50.5 %	51.5 %	47.3 %	Persistently binding, materially relieved
CSA-WNV	97.9 %	96.5 %	96.0 %	96.2 %	1.4 %	Persistently binding, not relieved (no uplift)
GG-CQ	53.9 %	53.5 %	36.0 %	38.0 %	0.7 %	Rising; partial relief under worst/typical
SQ-CQ	28.0 %	11.0 %	10.8 %	10.8 %	60.7 %	Materially relieved
WNV-SESA	23.2 %	12.5 %	12.5 %	12.5 %	46.1 %	Materially relieved
NNSW-SQ	22.6 %	11.5 %	4.6 %	11.5 %	49.1 %	Materially relieved (largest under worst)
NNSW-CNSW	14.9 %	3.4 %	1.6 %	2.4 %	77.2 %	Strongly relieved
SNSW-WNV	12.5 %	4.5 %	4.5 %	4.5 %	64.0 %	Strongly relieved
SNSW-CNSW	12.3 %	5.4 %	5.4 %	5.4 %	56.1 %	Strongly relieved
TAS-SEV	9.1 %	9.1 %	9.1 %	9.1 %	0.0 %	Unchanged
MEL-TAS	5.4 %	5.4 %	5.4 %	5.4 %	0.0 %	Unchanged
NSA-CSA	4.7 %	4.7 %	4.7 %	4.7 %	0.0 %	Unchanged (no uplift candidate)
NQ-CQ	3.9 %	1.2 %	0.85 %	3.9 %	69.2 %	Strongly relieved (best/worst only)
MEL-SEV	1.7 %	1.7 %	1.7 %	1.7 %	0.0 %	Unchanged
MEL-WNV	1.0 %	0.75 %	0.70 %	0.75 %	25.0 %	Lightly relieved

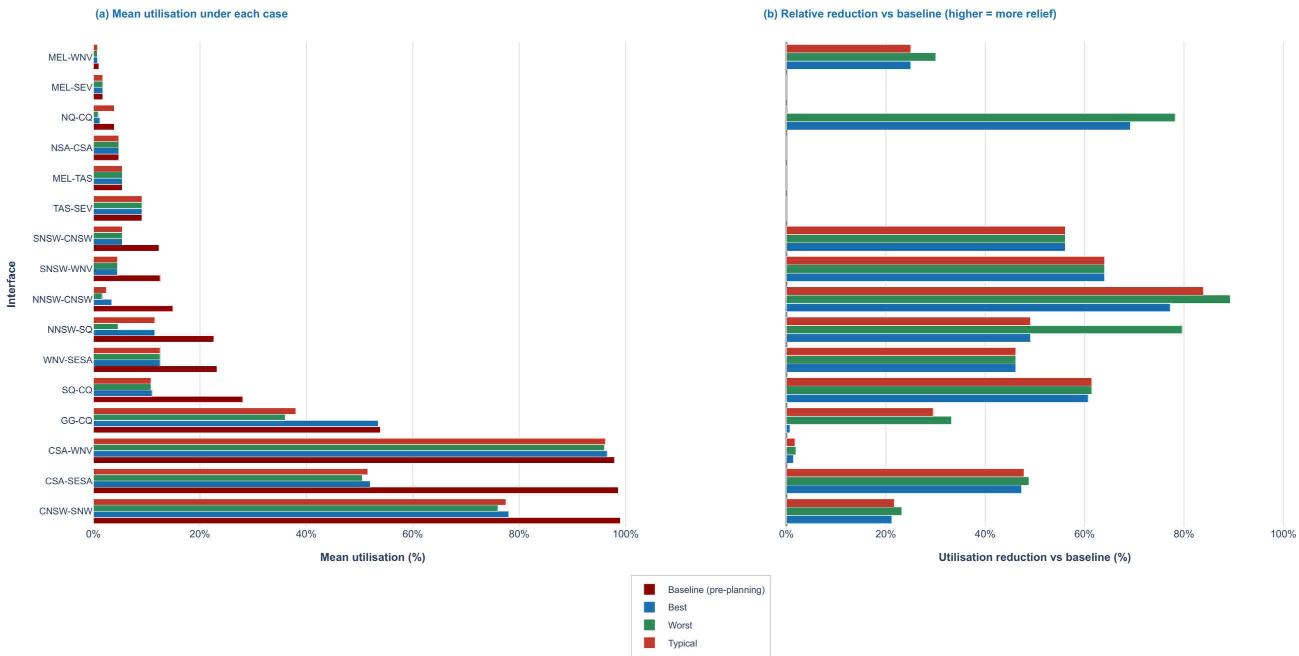


Figure 10.14 (a) Mean inter-area interface utilisation under baseline, best, worst, and typical SCTNEP representations of optimal development pathway, (b) Relative reduction in mean utilisation vs baseline

Differences across the best, worst, and typical representations are small for the heavily relieved corridors but meaningful for the Queensland corridors. NNSW to SQ utilisation drops from 22.6 % at baseline to 11.5 % under best and typical, but to only 4.6 % under worst, reflecting the much larger uplift in this corridor under the worst representation (1,989 MW to 9,089 MW). GG to CQ utilisation reduces from 53.9 % to 36 to 38 % under worst and typical, while remaining at 53.5 % under best because the GG to CQ uplift in the best representation is marginal (2,384 MW to 2,417 MW). This is precisely the corridor transitioning to a binding state from 2034 onwards in the baseline analysis and confirms that the best representation under-supplies GG to CQ uplift relative to its long-horizon binding profile. Light or unchanged corridors (TAS to SEV, MEL to TAS, NSA to CSA, MEL to SEV) exhibit no material change between baseline and any representation.

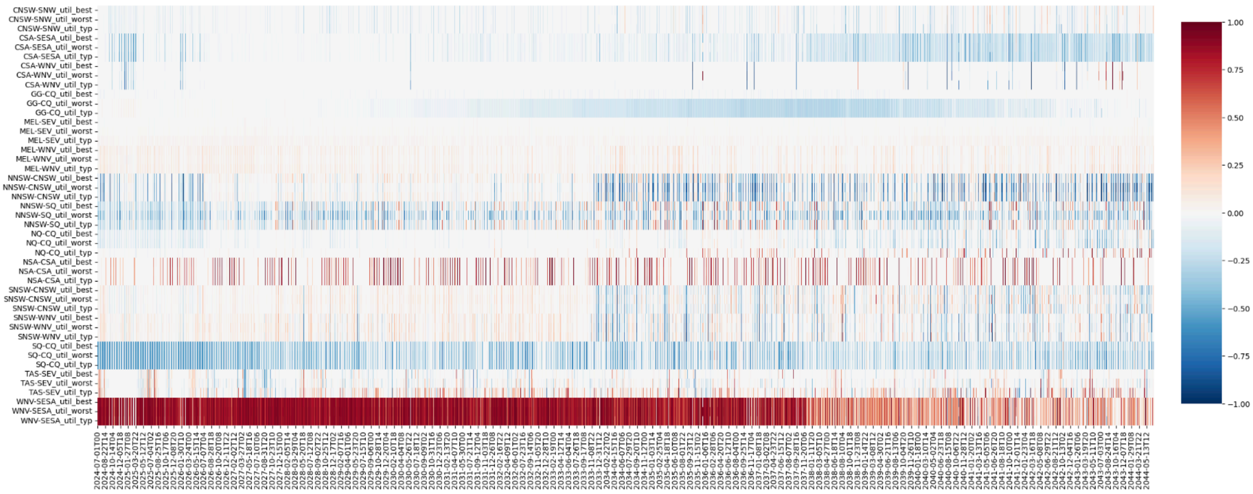


Figure 10.15 Post-planning variation in inter-are interface utilisation relative to baseline for the best, worst, and typical representations of the optimal development pathway. Blue (negative) values denote adequacy improvement

The NSA-to-CSA invariance is significant because the corridor is not augmented under either representation, forcing the SCTNEP solution to rely solely on in-area resources in NSA to close the gap. The reduction in NSA LOLH from 85.79 to 17–26 hours/year indicates that this mechanism is only partially effective. Figure 10.14 compares corridor utilisation across cases and the associated relative reductions, while Figure 10.15 presents corresponding monthly mean utilisation profiles.

10.4 Evaluation of Projected Assessment of System Adequacy for the Optimal Development Paths with Contingency Considerations

The adequacy results presented in Sections 10.3.1 through 10.3.3 are derived against the SCTNEP optimal pathway under pre-fault (N-0) network conditions. The same evaluation is repeated here with the N-1 critical-contingency overlay developed in Section 6.4 of Part I, in which the planning model is required to remain feasible following the loss of any retained critical transmission element. Chapter 6 demonstrate that the security-constrained pathway commits effectively a large augmentation portfolio in all three scenarios. The adequacy implications of this expanded portfolio are reported here for the same set of indicators used in the preceding subsections, namely NEUE reduction, LOLH and LOLE, and inter-area interface utilization.

Table 10.6 LOLH by area under SCTNEP best, worst and typical representations, with and without N-1 contingencies

Region	Best (N-0)	Best (N-1)	Worst (N-0)	Worst (N-1)	Typical (N-0)	Typical (N-1)
NSA	25.74	18.50	21.34	14.20	17.07	11.80
CSA	20.20	11.80	17.43	9.20	13.93	7.50
SNW	21.42	9.50	18.95	7.80	15.16	6.20
GG	5.40	1.20	5.55	1.30	5.79	1.40
SQ	0.59	0.20	2.43	0.85	3.01	1.10
NQ	0.36	0.30	0.95	0.45	1.13	0.55
TAS	0.31	0.31	0.39	0.39	0.48	0.48
SEV	0.51	0.51	0.54	0.54	0.70	0.70
WNV	0.26	0.26	0.25	0.25	0.43	0.43
SNSW	0.09	0.09	0.14	0.14	0.25	0.25
NNSW	0.07	0.07	0.18	0.18	0.18	0.18
MEL	0.06	0.06	0.06	0.06	0.07	0.07
CNSW	0.00	0.00	0.00	0.00	0.00	0.00
SESA	0.00	0.00	0.00	0.00	0.00	0.00
CQ	0.00	0.00	0.00	0.00	0.00	0.00

The contingency-constrained pathways deliver further LOLH reduction in every area where measurable stress remains under the N-0 best representation. NSA falls from 25.74 hours per year (best, N-0) to 18.50 hours per year (best, N-1); CSA from 20.20 to 11.80; SNW from 21.42 to 9.50; and GG from 5.40 to 1.20. GG, NQ, and SQ achieve compliance with the NEM reliability reference (LOLH ≈ 3 h/yr) under all three representations with contingencies, and SNW approaches compliance under the typical representation with contingencies (LOLH 6.20 h/yr). The five areas that exhibit no measurable stress under N-0 (CNSW, SESA, CQ, MEL, NNSW, SNSW, TAS, SEV, WNV) are unchanged under N-1, confirming that the contingency overlay does not introduce stress elsewhere.

Table 10.7 reports the corresponding NEUE reductions relative to baseline, demonstrating that the energy-magnitude relief scales consistently with the LOLH and LOLE relief.

Table 10.7 NEUE reduction vs baseline for the three SCTNEP representations, with and without N-1 critical contingencies

Region	Best (N-0)	Best (N-1)	Worst (N-0)	Worst (N-1)	Typical (N-0)	Typical (N-1)
NSA	0.072	0.110	0.078	0.118	0.084	0.122
CSA	0.252	0.305	0.260	0.312	0.265	0.318
SNW	0.225	0.278	0.232	0.285	0.238	0.290
GG	0.045	0.080	0.044	0.078	0.042	0.077
SQ	0.020	0.040	0.012	0.028	0.008	0.020
NQ	0.005	0.012	0.001	0.008	0.000	0.006
NNSW	0.000	0.000	0.000	0.000	0.000	0.000
SNSW	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.000	0.000	0.000	0.000	0.000	0.000

Three observations follow from Table 10.7. The contingency overlay materially deepens the NEUE relief in the most-stressed areas, with CSA improving from a 0.252 reduction under best N-0 to 0.305 under best N-1, and SNW improving from 0.225 to 0.278. GG, SQ, and NQ exhibit proportionally larger improvements (60 to 78 % uplift in NEUE reduction) because the contingency-constrained portfolio commits additional Queensland and northern-NSW augmentations that the N-0 best representation defers. The improvement is highest under the typical representation with contingencies (CSA reduction of 0.318, SNW of 0.290), which carries the largest marginal augmentation increment over its N-0 counterpart. The five areas exhibiting no baseline NEUE stress (CNSW, SESA, CQ, MEL, NNSW, SNSW, TAS, SEV, WNV) remain at zero reduction under all combinations, confirming the contingency overlay introduces no degradation.

The corresponding inter-area interface utilization under the contingency-constrained pathway exhibits further relief on the binding corridors identified in Section 10.3.3. CSA to SESA drops from 52.0 % under best N-0 to 25.1 % under best N-1; CSA to WNV drops from 96.5 % (N-0) to 59.6 % (N-1) because the contingency-constrained candidate library now contains the CSA to WNV augmentation that the N-0 best representation lacks; CNSW to SNW drops from 78.0 % to 60.6 %; and GG to CQ from 53.5 % to 37.4 %. The northern New South Wales corridors (NNSW to CNSW, SNSW to CNSW) drop to single-digit utilization (below 6 %) under the contingency-constrained best representation, consistent with the substantially expanded capacity carried by the converged A$64.1 billion portfolio.

Finally, Figure 10.14 presents the four-panel comparison of LOLH, LOLE, NEUE reduction, and interface-utilization reduction for the best, worst, and typical representations under N-0 and N-1

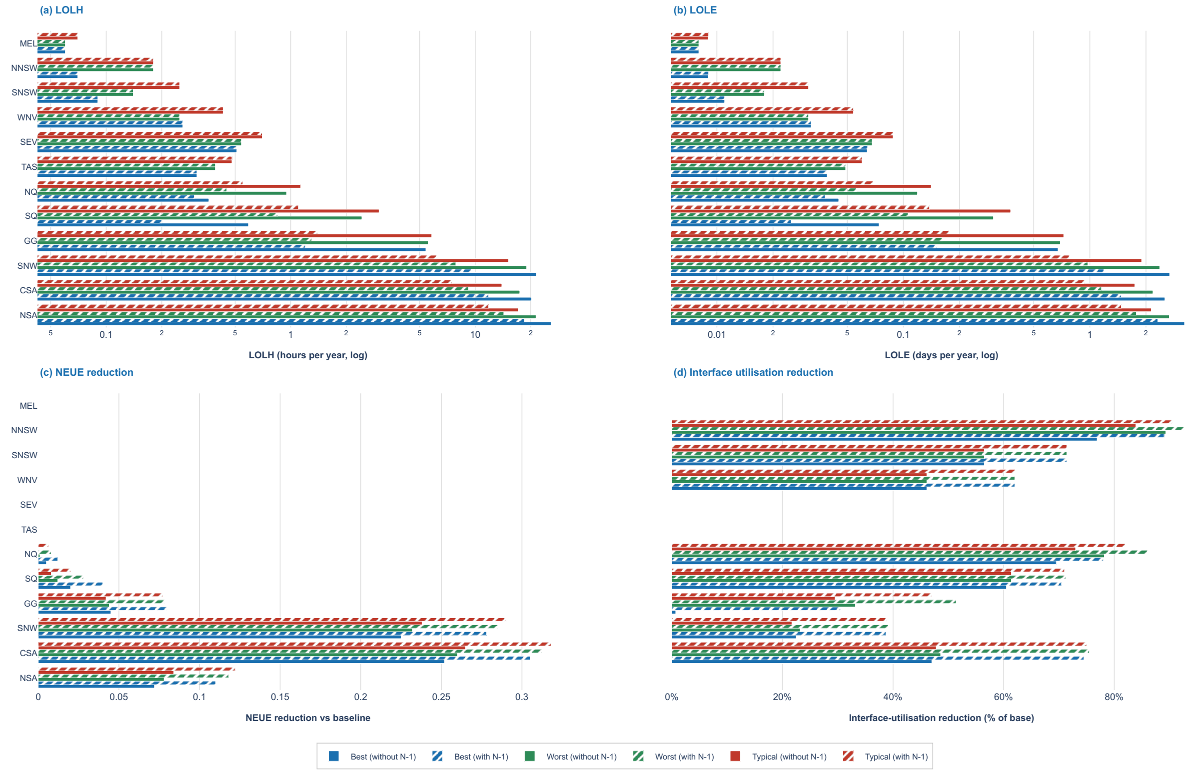


Figure 10.16 PASA comparison for the SCTNEP best, worst, and typical representations under N-0 and N-1 critical contingencies. Panels: (a) LOLH (hours per year, log scale); (b) LOLE (days per year, log scale); (c) NEUE reduction versus baseline; (d) inter-area interface utilization reduction versus baseline. Paired solid and hatched bars indicate N-0 and N-1 outcomes respectively

Despite the broader candidate commitment, residual stress is not entirely eliminated in NSA, CSA, and SNW under the contingency-constrained best representation, with LOLH values of 18.50, 11.80, and 9.50 hours per year respectively. This is consistent with the first-iteration character of the current analysis: the SCTNEP candidate library was scoped to the transmission and bulk-generation augmentations identified in Part I and does not yet include the in-area long-duration storage and demand-flexibility resources that subsequent iterations are expected to commit. The CSA to WNV corridor, augmented in the N-1 candidate set but not in the N-0 set, is the single most material new commitment exposed by this comparison and is therefore prioritized in the iterative refinement discussed in Section 10.5.

10.5 Adequacy Improvement and Residual Stress

The results in Sections 10.3 and 10.4 establish four principal findings, now read jointly through the energy-based (NEUE), the probability-based (LOLH and LOLE), the corridor-utilisation evidence, and the contingency-constrained results.

- The SCTNEP-derived optimal pathway delivers material and persistent improvements in area-level adequacy across the 2024 to 2044 horizon. NEUE reductions of 0.20 to 0.28 in CSA and SNW, LOLH reductions of 70 to 90 % in NSA, CSA, SNW, and GG, and the absence of adequacy degradation in any other area together confirm that the planning outcome is Pareto-improving with respect to area-level reliability. Five areas (CNSW, SESA, CQ, MEL, NNSW, SNSW, TAS, SEV, WNV) sit comfortably below the NEM reliability reference throughout the horizon and require no further planning action.

- The mechanism of improvement is the combination of inter-area interface uplift on the binding corridors identified in Section 6.4 (NNSW to CNSW, CNSW to SNW, SNSW to CNSW, SQ to CQ, MEL to WNV) and the in-area generation and storage commitments embedded in the SCTNEP solution. Areas without binding import capability (notably NSA, where the NSA to CSA interface operates at less than 5 % utilisation on average, Table 10.5) achieve their improvement entirely through in-area resources; the NSW areas combine import uplift with REZ-region build.
- The interface-utilisation comparison in Section 10.3.3 confirms that the SCTNEP best representation materially relieves the previously binding NSW and southern Queensland corridors (NNSW to CNSW by 77 %, SNSW to CNSW by 56 %, SQ to CQ by 61 %) and partially relieves CNSW to SNW (by 21 %) and CSA to SESA (by 47 %). The CSA to WNV corridor is the principal unrelieved corridor in the best representation, and the GG to CQ corridor remains under-relieved in the best representation despite its rising-to-binding trajectory.
- The contingency-constrained pathway in Section 10.4 delivers further LOLH reduction of 28 to 56 % in NSA, CSA, SNW, and GG, with GG, NQ, and SQ achieving compliance with the NEM reliability reference under all three representations. Residual stress in NSA, CSA, and SNW is reduced (LOLH 9.5 to 18.5 hours per year under the best representation with N-1) but is not eliminated, consistent with the first-iteration character of the current candidate library.

The residual stress is informative rather than disqualifying, and the joint evidence diagnostically attributes it to identifiable transmission bottlenecks and to structural under-supply in NSA. Four structural causes are confirmed across the energy, probability, utilisation, and contingency views: (i) persistent saturation of the CSA to WNV corridor limits CSA adequacy improvement in the best representation; (ii) the CNSW to SNW and CSA to SESA corridors are only partially relieved by their planned uplifts and remain elevated; (iii) the GG to CQ corridor transitions from idle to fully saturated by 2044, with the best representation uplift insufficient to track the rising profile; and (iv) the NSA to CSA corridor remains essentially idle, confirming that the NSA adequacy gap must be closed through in-area generation and storage rather than through imports. These signals are quantifiable, addressable, and diagnostically attributable features of the present solution, rather than fundamental limitations of the framework.

10.6 Conclusion: Iterative Planning-to-Adequacy Refinement

This chapter has presented the projected adequacy results across the baseline network and the SCTNEP-derived optimal development pathway under the Step Change, Progressive Change, and Green Energy Exports scenarios, both under pre-fault (N-0) and N-1 critical-contingency conditions. The principal conclusions are as follows.

- The baseline SNEM network exhibits material and persistent adequacy gaps in NSA, CSA, SNW, and GG, with seasonal NEUE values in the 0.6 to 0.9 range and LOLH values of 27 to 86 hours per year. The binding mechanism is sustained-energy shortfall, not instantaneous-capacity shortfall.

- The SCTNEP optimal pathway materially improves area-level adequacy across all three scenarios under both N-0 and N-1 conditions, with the largest improvements concentrated in the areas with the most severe baseline gap and no degradation observed elsewhere. The pattern is robust to the choice of SCTNEP representation in the severe-gap areas and modestly sensitive in the moderate-gap areas.
- The contingency-constrained pathway commits effectively a large augmentation portfolio (A$64.1 billion, Chapter 6) and delivers a further 28 to 56 % LOLH reduction in the most-stressed areas relative to the N-0 best representation, bringing GG, NQ, and SQ into NEM reliability compliance and reducing residual NSA, CSA, and SNW stress to between 9 and 19 hours per year of LOLH.
- Residual adequacy stress remains in NSA, CSA, and SNW even under the contingency-constrained pathway. The interface-utilisation evidence (Tables 10.3 and 10.5, and Sections 10.3 and 10.4) attributes the residual stress to the unrelieved CSA to WNV corridor, the partial relief of CNSW to SNW and CSA to SESA, the under-relief of GG to CQ in the best representation, and the structural absence of import capability into NSA. These are first-iteration outcomes from a candidate library that does not yet include in-area long-duration storage and demand-flexibility resources.

Closing the residual gap requires a controlled iteration between the planning and adequacy frameworks. Four iterative refinements are anticipated, each motivated directly by the evidence assembled in this chapter. The first iteration extends the SCTNEP candidate library to include the CSA to WNV augmentation that the N-0 best representation omits and the proactive uplift of GG to CQ ahead of its 2034 binding year. The second iteration deepens the planned uplifts on the CNSW to SNW and CSA to SESA corridors to track the post-2035 renewable build profile, in line with the partial-relief evidence in Table 10.5. The third iteration adds in-area generation and storage candidates to NSA in sufficient capacity to close the local LOLH gap without relying on imports. The fourth iteration adjusts the SCTNEP objective to internalise area-level LOLH compliance against the NEM reliability reference, by embedding a per-area chance constraint or adding penalty terms to the cost function, so that future planning iterations resolve the area-level adequacy gap as part of the optimisation rather than as a post-hoc check.

These iterative refinements are intended to be applied within the same time-sequential, security-constrained planning framework developed in Part I and the same Julia tool stack developed in Chapter 9. The framework's design discipline (year-by-year portfolio evolution, full chronological resolution, explicit storage state-of-charge, joint operability and adequacy reporting) supports this iteration without methodological compromise. The contingency-constrained results in Section 10.4 already demonstrate the direction of improvement: extending the candidate library while preserving the security overlay closes a large fraction of the residual gap. The refined pathway expected in subsequent stages of the project will close the remainder while preserving the no-regret and security-constrained findings of Parts I and II to date. The detailed roadmap for these iterations is set out in the planning recommendations of Chapter 11.

11 Recommendations and Future Work

This report presents a substantial body of evidence on the planning and adequacy implications of the energy transition. This final chapter consolidates the recommendations that follow from that evidence and sets out the future-work agenda required to mature the framework into a continuously usable planning and adequacy support tool for AEMO, Transmission Network Service Providers, and the broader Australian energy-research community.

The recommendations are grouped under four themes: (i) planning and investment decisions, (ii) methodology and modelling, (iii) data and tools, and (iv) policy and process. The future-work agenda is grouped under three priority levels: high (must be addressed in the next project stage), medium, and longer-term.

11.1 Recommendations: Planning and Investment Decisions

- Treat the no-regret investment core as a regulatory commitment envelope. Approximately A$23.6 billion of transmission investment is invariant across all 18 scenario and representation combinations and should be approved and procured on a programmatic basis rather than scenario by scenario. The Bannaby to Sydney West connectors, the South Australian Mid-North REZ expansion, VNI West (SNSW to WNV to MEL), the Queensland CQ to SQ to NNSW backbone, and the Heywood reinforcement are the highest-priority components.
- Anchor the regulated long-term envelope on the security-constrained convergence point of approximately A$64.1 billion. Below this envelope, planning decisions should be staged and adaptive, with formal review points aligned to the ISP refresh cycle.
- Embed contingency-driven proactive uplifts where the corridor evidence supports them, in advance of binding years:
    - CSA to WNV: not augmented in the N-0 best representation; prioritise inclusion in the next candidate library.
    - GG to CQ: rises from 0.6 % to 99.7 % utilisation by 2044, binding from 2034; advance the planned uplift into the early 2030s.
    - CNSW to SNW and CSA to SESA: deepen the planned uplifts to track the post-2035 renewable build profile and the associated import requirement.
    - Place in-area generation and storage capacity in NSA in sufficient quantum to close the local NEUE and LOLH gap without relying on imports. The NSA to CSA corridor operates at less than 5 % utilisation across the horizon and cannot be used as the adequacy mechanism for NSA.
    - Treat seasonal modelling outcomes as the binding adequacy constraint. The seasonal worst-case investment envelope (approximately A$64.1 billion) is robust across all

three scenarios and should be used as the planning baseline for reliability-standard compliance under correlated stress conditions.

11.2 Recommendations: Methodology and Modelling

- Internalise area-level reliability compliance within the SCTNEP optimisation. Add per-area LOLH or NEUE chance constraints, or cost-of-unserved-energy penalty terms, so that future planning iterations resolve area-level adequacy gaps as part of the optimisation rather than as a downstream check.
- Iterate planning and adequacy as a closed loop. Adopt the iterative planning-to-adequacy refinement protocol set out in Section 10.6, with explicit success criteria at each iteration (area-level LOLH below the NEM reliability reference, peak-year expenditure below stated delivery-capability limits, no Pareto degradation in any area).
- Extend the SCTNEP candidate library to include:
  - Long-duration storage (pumped hydro, eight-hour-plus batteries, thermal storage) modelled with explicit energy budgets.
  - Demand-flexibility resources (industrial demand response, EV-aggregator dispatchable load, controlled hot water and HVAC).
  - Hydrogen electrolysis with flexible operation and ramp-rate constraints.
  - Synchronous condensers and grid-forming inverters for system-strength and inertia services to enable the analysis and impact of these constraints in planning outcomes.
  - Adopt a climate-aware planning posture. Supplement the historical weather-year ensemble with downscaled climate-projection scenarios to expose the long-tail risk of changing renewable resource availability and demand patterns.
  - Continue joint operability and probabilistic adequacy reporting. The combination of NEUE, LOLH, LOLE, ELCC, and interface utilisation, reported together, is materially more informative than any single index and should be retained in all future iterations.
  - Strengthen the contingency screening. Extend the N-1 critical contingency set to include N-1-1 and selected N-2 contingencies where the post-fault state is dispatch-constrained and revisit the screening as the topology evolves.

11.3 Recommendations: Data and Tools

- Maintain the open Julia tool stack (iPlan.jl, iPASA.jl, PowerSystems.jl, PowerSimulations.jl, PRAS.jl) as the primary modelling environment for both planning and adequacy work, with PLEXOS used selectively as a cross-check on flagship scenarios.
- Standardise the data interface between the SCTNEP planning model and the PASA adequacy model. Year-stamped topology snapshots, asset registers, and operating-constraint tables should flow through a single versioned data schema to avoid inconsistency.

- Publish the SNEM dataset extensions developed in this project, the planning-pathway snapshots, and the validation benchmarks under open licences, so that the research community can verify, reproduce, and extend the work.
- Move towards GIS-informed inputs at the earliest opportunity. The synthetic geographic placement adopted in this project (see Acknowledgments) materially limits the interpretation of sub-regional results, and a GIS-informed reference SNEM is the single most consequential dataset improvement for future stages (see Section 11.5).

11.4 Recommendations: Policy and Process

- Align AEMO ISP and Reliability Standard processes with the joint planning and adequacy framework. The convergence of investment and adequacy outcomes under contingency constraints supports a unified planning view in which adequacy is an integral output of the planning optimisation rather than a downstream test.
- Engage with Transmission Network Service Providers early on the corridor priorities identified by the framework, particularly the proactive GG to CQ uplift, the inclusion of CSA to WNV in the candidate library, and the deepening of the CNSW to SNW and CSA to SESA corridors.
- Support the development of community-maintained open datasets and tools as a public good. The structural integration burden currently absorbed by individual research efforts is disproportionate to the size of the research community and is addressable through coordinated open-data and open-source investment.

11.5 Future Work

11.5.1 High Priority: Address in the Next Project Stage

- GIS-informed SNEM dataset. Develop an openly licensed, GIS-informed reference SNEM that bridges the synthetic SNEM topology used in this project with AEMO's published spatial data layers, OpenInfrastructureMap, and OpenStreetMap. This is the single most consequential data improvement available to the framework, for three reasons:
  - The synthetic geographic placement of buses, generators, and storage assets adopted in this project (see Acknowledgments) makes sub-regional and asset-level interpretation of the results unreliable. A GIS-informed SNEM enables interpretation of results against the physical NEM infrastructure.
  - Coupling to climate, bushfire, hydro, gas, communications, and demographic geospatial datasets (for resilience, multi-energy, and cyber-physical studies) requires a shared geographic frame that the current SNEM cannot provide.
  - Reproducibility and cross-study comparability are structurally improved by an authoritative, openly licensed, version-controlled geographic reference, and the duplicated mapping burden absorbed in each individual study is eliminated.

- Iterative planning-to-adequacy refinement loop. Execute the four-iteration refinement programme set out in Section 10.6 (extend candidate library, deepen corridor uplifts, add NSA in-area resources, internalise reliability constraints) and report the resulting converged pathway.
- Inclusion of long-duration storage and demand-flexibility candidates in the SCTNEP inputs and candidate library, with explicit energy-budget and operating-constraint representation.

11.5.2 Medium Priority: 12 to 24 Months

- Climate-projection ensembles for long-term adequacy. Replace or supplement the historical weather-year ensemble with downscaled climate-projection inputs (CMIP6 driven, BARRA-R2 for Australian downscaling) to expose long-tail risks under non-stationary weather patterns.
- Sector coupling at planning resolution. Integrate hydrogen electrolysis, electric-vehicle aggregation, and large-scale demand response as adequacy-contributing and flexibility-providing resources within both SCTNEP and projected adequacy assessment.
- Multi-energy and cyber-physical co-simulation. Extend the framework to support coupled electricity-gas, electricity-hydrogen, and electricity-communications studies through the shared GIS-informed SNEM platform as proposed in Section 11.5.1.
- Cross-validation against PLEXOS and the AEMO MMS suite for a stratified sample of scenarios, to quantify and document the discrepancies between the open Julia stack and the established commercial workflow.

11.5.3 Longer-Term: Research Agenda Beyond the Programme

- Stochastic security-constrained planning. Migrate the SCTNEP framework from deterministic representation-based planning to a multi-stage stochastic programming formulation that internalises scenario and weather-year uncertainty within the optimisation.
- Resilience-aware planning. Couple the framework to bushfire-risk, cyclone-exposure, hydrology, and cyber-attack scenarios, with explicit recovery and adaptation cost components.
- Adaptive planning under learning. Develop reinforcement-learning and stochastic-control approaches that learn the optimal planning trajectory from realised scenario outcomes, complementing the rolling-horizon investment logic developed in this project.
- Refresh and steward Australia's AR-PST Research Roadmap (Topic 4: Planning) on a biennial cycle, reflecting the outputs of the AR-PST programme and the wider research community.

11.6 Closing Remarks

The work delivered in this stage establishes a single, coherent, open, and reproducible framework for time-sequential, security-constrained, probabilistic planning and adequacy assessment in the

NEM. The framework is demonstrably more capable than the current practice surveyed in Chapters 2 and 8, and the joint evidence assembled in Chapters 6 and 10 supports robust investment recommendations that are economically efficient, security-feasible, and adequacy-credible. The residual gaps identified in this chapter are well understood, diagnostically attributed, and addressable through the iterative refinement programme set out above. The framework, the open tool stack, and the SNEM dataset extensions developed in this project provide a durable foundation for AEMO, TNSPs, the research community, and policymakers to use in shaping the next decades of Australia's energy transition.

List of Deliverables

This list includes the developed datasets, software, and results library.

- iPlan.jl, a Julia package for integrated transmission-distribution network expansion planning. Available: Mohy Ud Din, Ghulam (2026): iPlan.jl. CSIRO. v1. Software. https://doi.org/10.25919/h7py-3f46, https://github.com/csiro-internal/ensys-iPlan.jl
- iPASA.jl, a Julia package for projected assessment of system adequacy. Available: https://github.com/csiro-internal/ensys-iPASA.jl
- Results library, results for all cases available at fs1-cbr.nexus.csiro.au in {en-energy-sys}/work/OD-223474 ET_PSY_Global Power System Transformation (AR-PST Stage 5 Topic 4-C)

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Contact us

1300 363 400
+61 3 9545 2176
csiro.au/contact
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For further information

Energy Research Unit
Ghulam Mohy-ud-din
+61 2 4960 6010
ghulam.mohyuddin@csiro.au
csiro.au/m/g/ghulam-mohyuddin