Enhanced System Planning Project

C4NET | ESP Enhanced System Planning

C4NET Project Overview

Techno-Economic Modelling of Non-Network Solutions

Work Package 2.9

April 2025

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1. Purpose of the report

The Enhanced System Planning (ESP) project is a significant and collaborative research project aimed at informing sub transmission level electricity planning in Australia beyond 2030. Its focus is on building methodologies and approaches for bottom-up modelling and to highlight the opportunities presented through the distribution system and by integrating Consumer Energy Resources (CER) and Distributed Energy Resources (DER), with the goal of informing whole of system planning. The ESP seeks to inform gaps that would emerge if the Australian Energy Market Operator's (AEMO) current Integrated System Plan (ISP)[1] is expanded beyond its current scope to take a more whole-of-system approach in alignment with the Energy and Climate Change Ministerial Council's (ECMC) recommendations for enhancing energy demand forecasting in the ISP.[2] The ESP project is targeted at addressing the distribution system considerations aspect of this expanded scope, with particular focus on bottom-up modelling approaches from the low voltage distribution upwards, as outlined in *Figure 1*. For the bigger picture of integration with the ISP see *Appendix Two.*

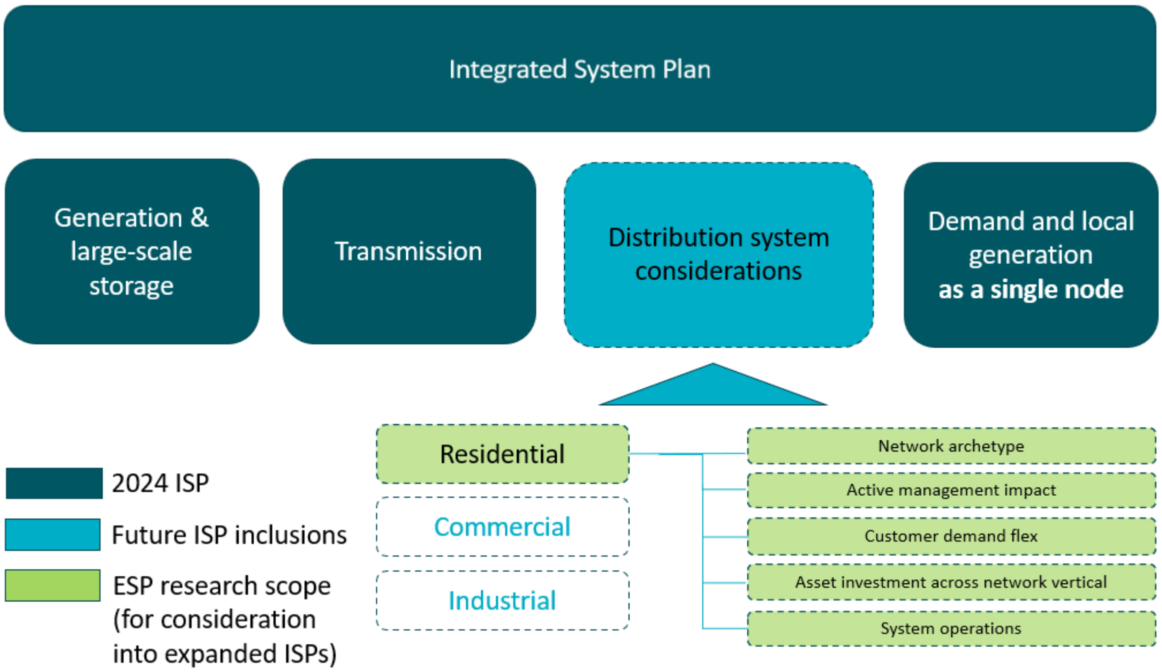


Figure 1 – Relationship between ISP and ESP

This has been addressed through fifteen projects across three distinct work packages:

- **Work package one:** Key inputs, methodologies, and demand network implications of electrification to inform foundational elements of bottom-up modelling.

[1] 2024 Integrated System Plan (ISP), Australian Energy Market Operator, June 2024

[2] Review of the Integrated System Plan: ECMC Response, ECMC, April 2024

- **Work package two**: Impact of flexibility options within distribution networks Techno-economic implications of future architectures.
- **Work package three:** Active distribution network considerations for whole-of-system planning implications: technical, economic and policy

A key project of work package two, Melbourne University undertook an independent research project: Techno-Economic Modelling of Non-Network Solutions (WP 2.9), with the focus on the techno-economic modelling and impact assessment of integrating CER/DER flexibility into distribution system planning (DSP). The project provides a theory-based, structured, transparent and implementable decision-making framework to assess the risks, costs, and benefits when leveraging CER/DER-based, non-network options as an alternative to, or in conjunction with, network augmentation at any level in distribution systems (LV, MV, sub-transmission), especially in the context of significant electrification and planning uncertainties.

The project proposes to enhance the current DNSP planning frameworks to explicitly account for scenario-based uncertainties (exogenous and endogenous) when valuing all investment options, in particular, demand-side resources, and implement comprehensive multi-scenario analysis to strategically guide the economic deployment of alternatives, optimising the timing of investments and avoiding the creation of potentially stranded network assets by aligning decisions with diverse possible future states of the system. The standardised methods for valuing the benefits of flexibility (investment and operational) across all resource types (network and non-network technologies) will ensure fairer comparisons and incentivise the development of adaptable and value-adding solutions.

This summary report is designed to guide stakeholders in their understanding of the proposed techno-economic modelling framework.

In addition, C4NET has sought through this report to summarise and evaluate the research, identify any opportunities or limitations with the approach taken, and highlight any observations or insights for distribution network service providers (DNSPs), regulators and policy makers and market operators and for future research. This has also been done taking into consideration broader consultation and a range of stakeholder views and seeks to maintain a focus on consumers as the beneficiaries of an integrated energy system.

2. Project Summary

Australia has experienced a significant increase in the adoption of CER/DER over the past decade, especially in solar photovoltaic and distributed battery storage systems. The significant adoption of CER/DER marks a fundamental transformation in electricity systems, especially on distribution grids. End users have progressed from passive consumers to active participants in the generation and storage of energy. While non-controllable CER/DER could pose operational and planning challenges, it has been proven that establishing effective control strategies and information and communication technologies (ICT) to actively manage these assets, with customer consent, can create significant opportunities for enhancing the operation of distribution systems. Such controlled resources, or non-network solutions (NNS) where relevant, would enable operators to maintain better control of the system during periods of network stress, potentially decreasing or delaying the need for costly and extensive network upgrades.

In the medium to long term, varying DER adoption levels and demand growth trends introduce significant uncertainty in network planning posing substantial risks of under or over investment in long-life network assets, which ultimately leads to increased costs for consumers. The Techno-Economic Modelling of NNS research project proposes enhancements to the current DNSP planning framework by incorporating scenario-based uncertainties in the assessment framework which explicitly values the flexibility introduced by NNS. The project provides a theory-based, structured, transparent and implementable decision-making framework to assess the risks, costs, and benefits when leveraging CER/DER-based NNS as an alternative to network augmentation at any level in the distribution systems (LV, MV, sub-transmission). To illustrate the proposed framework, two case studies using a sample illustrative sub-transmission network and a real-life sub-transmission network topology from WP1.4 were used. The project's relationship with other research projects in Work Packages 1 & 2 is illustrated in *Figure 2* below.

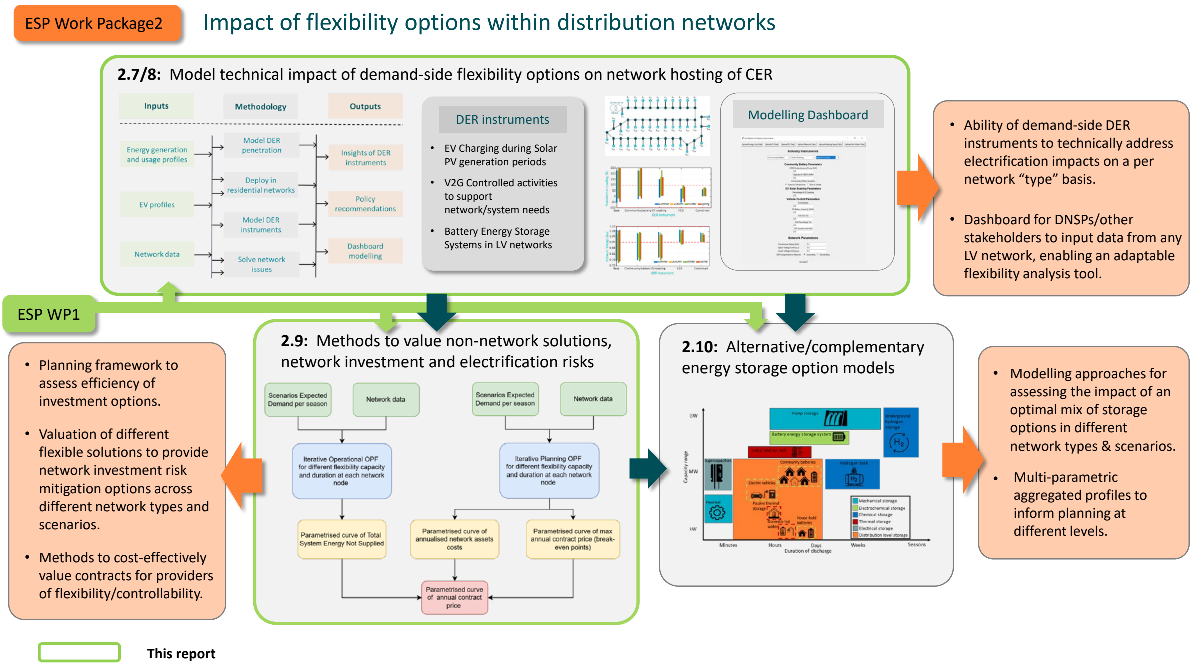


Figure 2 – Relationship between this research project and other projects in Work Packages 1 & 2

3. Research methodology and approach

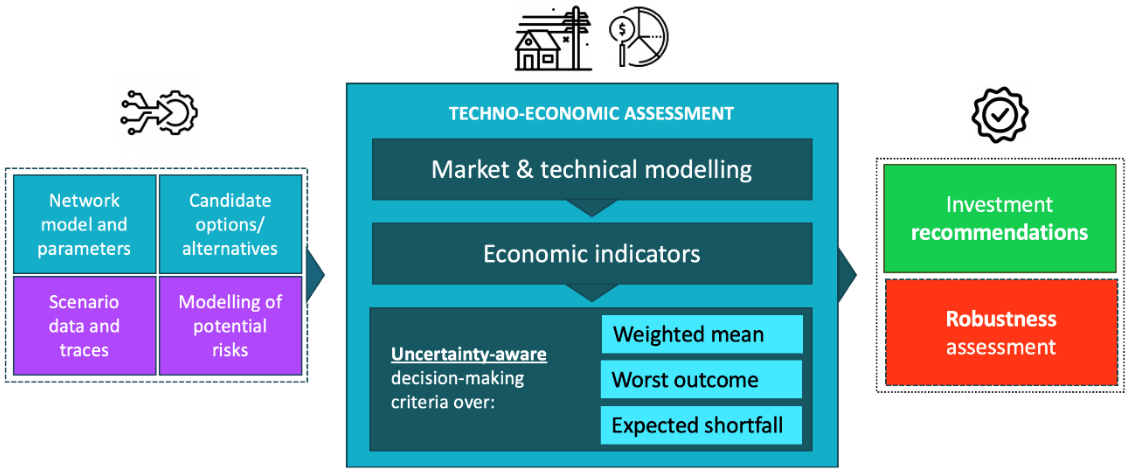


Figure 3 - General structure of the proposed decision-making framework

Figure 3 presents the overarching structure of the proposed decision-making framework. One of the most relevant features of the framework is the possibility to iteratively **perform combined multi-criteria analysis** over different metrics. This allows for a comprehensive understanding of the costs, potential regrets (as a measure of risk), and more in general, techno-economic benefits associated with selecting each investment alternative.

This methodological approach follows a modular process wherein a diverse set of candidate alternatives, encompassing both network and non-network solutions suitable for addressing an **identified system need**, are evaluated against a range of plausible scenarios. The performance of alternatives is quantified using a suite of pertinent economic indicators. Subsequently, the framework employs appropriate decision-making functionals and criteria to provide recommendations about preferred options and their associated economic value. In addition, it informs the potential development of operational payments related to the activation of non-network options.

3.1 Methodology

Figure 4 presents a detailed technical schematic of the proposed decision-making framework, which comprises seven distinct modules. The schematic delineates the interactions and information flow between these modules, each designated by a letter (A to G) for unambiguous identification. The subsequent sections provide a more detailed description of each module.

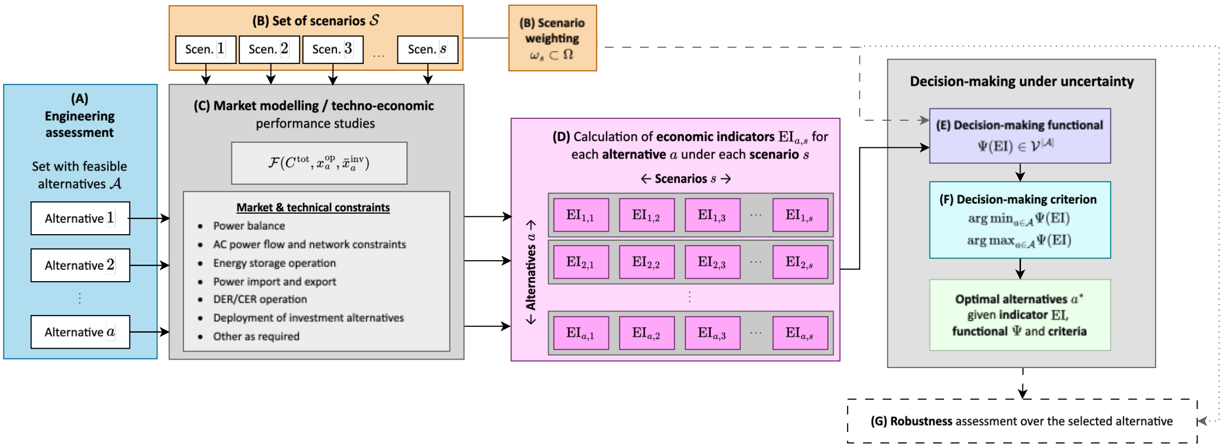


Figure 4 - Technical overview of the decision-making framework

3.1.1 Module (A) - Generation of alternatives to address an identified system need

In the context of distribution system planning in Australia, an **identified system need** represents a specific objective that a distribution company aims to achieve through investment. To address a system need, investment alternatives, named more broadly as **credible options** in the Australian regulation, can be systematically generated through engineering assessments. Depending on their technical characteristics, these can be broadly categorised as:

- **Network augmentation**: Network reinforcements like substation expansions, line upgrades, or transformer replacements.
- **Non-network solutions**: Including demand response (DR) programs, battery energy storage systems (BESS), distributed generation (DG), among others.

Once these alternatives and their technical characteristics have been determined to provide a feasible solution to an identified system need, the complete set of potential alternatives $\mathcal{A}$ is generated and established. An illustrative example of the set of alternatives is presented in Table 1. It is expected that each alternative includes a detailed description of its technical specifications and estimated capital expenditure, where applicable. For non-network options, the determination of precise capital costs may present challenges. In such cases, such cost could comprise the establishment costs associated with the control and communication infrastructure necessary for the effective management of these assets. The incentives required to solicit the required response can be determined in the subsequent economic assessment.

Example set of alternatives $\mathcal{A}$			
#	**Alternative**	**Technical characteristics**[3]	**Estimated capital / establishment cost**
1	Network augmentation Conductor type 1	All aluminum conductor (AAC) – Type 1	$ 10,000/km/MVA
2	Network augmentation Conductor type 2	All aluminum conductor (AAC) – Type 2	$ 12,500/km/MVA
3	Network augmentation Conductor type 3	All aluminum conductor (AAC) – Type 3	$ 15,000/km/MVA
4	Demand-side participation Alternative 1	Voluntary load reduction of 20 MW for 16 hours a year	$ 2,000 – 12,000/MW (coordination cost)[4]
5	Demand-side participation Alternative 2	Voluntary load reduction of 10 MW for 16 hours a year	$ 2,000 – 12,000/MW (coordination cost)
6	Battery energy storage	20 MW, 4-hour energy storage system	$ 2,000 – 12,000/MW (coordination cost)

Table 1 - Illustrative example set of feasible alternatives to address a specific system need

3.1.2 Module (B) - Scenario design with uncertainty and risk considerations

Modern power systems are characterised by increasing uncertainty stemming from various exogenous and endogenous factors. Examples of these factors could include the penetration level of variable renewable energy sources, trends in DER adoption, load growth, and market fluctuations, such as energy prices and policy incentives. To effectively address these uncertainties within the proposed framework, decision-makers are encouraged to develop a comprehensive set of scenarios representing a range of plausible future system states.

Module (B) focuses on the design of scenarios that explicitly account for relevant uncertainties and risks. Firstly, when formulating the scenario set, the decision-maker must identify the parameters subject to uncertainty and establish reasonable input values across these scenarios. While the uncertain parameters employed in scenario design may vary depending on the specific case, general considerations for uncertain parameters at the distribution system planning level could include:

- Peak growth and underlying demand profile: Variations in the growth rate of peak load and demand profile (e.g., a decrease in minimum demand) are expected to occur, influenced by electrification trends and demand response. These considerations could reveal potential security or thermal issues as well as requirements for additional generation or storage systems.
- DER uptake levels: Changes in installed distributed generation and storage, affected by technology costs and policy. Scenarios may range from slow to rapid DER uptake.

[3] These characteristics are purely illustrative and only aim to give a general description of the technical aspects that should be detailed.
[4] Project EDGE Independent Full CBA Report https://arena.gov.au/knowledge-bank/aemo-project-edge-independent-cba-full-report/.

- DER operational behaviour: Assessing performance and availability is critical when considering the provision of DER services (e.g., power injections or energy storage). Exploring a range of scenarios with varying levels of available capacity can offer a more comprehensive understanding of their potential as viable planning alternatives.
- Electricity supply costs: Volatility in wholesale prices, fuel costs, and network tariffs, impacted by renewables and regulations could create significant uncertainty in the electricity supply costs.
- Policy changes: Alterations in government regulations and incentives could affect the deployment of renewables and DER.
- Capital expenditure of investment options: Upfront infrastructure costs could be influenced by global markets, technology development and supply chain issues.

Once the decision-maker has defined the parameters subject to uncertainty, the scenarios are established. Each scenario is characterised by a specific variation trend for the relevant uncertain parameters. The number and selection of reasonable scenarios must be commensurate with the credible options under consideration. Scenario design involves the collation and development of data associated with these scenarios, as well as the consideration of varying parameter levels. For example, a decision-maker may evaluate three potential peak demand levels (low, medium, and high) in conjunction with two DER uptake levels (low and high), resulting in a total of six scenarios. Table 2 illustrates the construction of such a scenario set.

Example set of scenarios $\mathcal{S}$		
Scenario	**Uncertain parameter #1:** Demand level	**Uncertain parameter #2:** DER uptake
#1	High demand	High uptake
#2		Low uptake
#3	Medium demand	High uptake
#4		Low uptake
#5	Low demand	High uptake
#6		Low uptake

Table 2 - Illustrative example set of scenarios to assess the candidate alternatives

A complementary approach for the design of scenarios may involve incorporating evolving trends from relevant stakeholders or third-party entities. In Australia, AEMO develops plausible scenarios for the development of the Integrated System Plan (ISP), which model trends in the electricity system, including electrification, demand growth, DER uptake, and other pertinent parameters. These scenarios can serve as a baseline for characterising potential changes and forecasts concerning the distribution system under assessment.

Accounting for specific risks through sensitivity analysis

As previously discussed, the development of a comprehensive scenario set aims to explicitly integrate parametric uncertainties into the decision-making process. However, decision-makers may require consideration of specific parameter variations and potential risks.

It is feasible to augment the original scenarios by introducing targeted variations in the parameters under scrutiny to assess their impact and explicitly incorporate these risks into the decision-making process. Subsequently, these modified scenarios can be treated as distinct scenarios and assigned reduced weightings, reflecting their representation of system conditions with lower probabilities of occurrence.

Scenario weighting

The subsequent step in the scenario design involves **assigning a reasonable probability weighting** to each scenario formulated, reflecting their likelihood of occurrence. This process is essential for generating a transparent and robust ranking of credible investment options. Such weighting considerations aim to:

- Reflect likelihoods: Based on available evidence and expert judgment, assign weightings to the set of scenarios. Eventually, scenarios deemed more probable would be assigned greater weights.
- Incorporate stakeholder perspectives: Adjust weightings to align with policy objectives, regulatory constraints, and stakeholder risk preferences. If a planner is keen to focus on a more extreme (although unlikely) or risky scenario, the natural step would be to increase its weight to emphasize its material impact on the assessment.

For instance, in situations where DER adoption exhibits high uncertainty, planners may allocate greater weight to conservative scenarios to mitigate potential risks. A comprehensive analysis would encompass multiple weighting cases, exploring a range of reasonable weight allocations to ensure the robustness of the recommendations across varying weighting approaches. Each case would be associated with a specific array of weightings, enabling the assessment of potential changes in recommendations resulting from variations in these weightings. Instead of relying solely on best-case or worst-case scenarios, this approach acknowledges and quantifies the decision-maker's exposure to uncertainty by representing the probabilities of occurrence of diverse outcomes.

For example, considering the scenario set presented in Table 3 illustrates a potential allocation of weights across the relevant scenarios, reflecting different assumptions regarding future system states. It is imperative to note that the sum of the weightings for each independent case must equal 100%.

Example set of scenarios $\mathcal{S}$			**Example set of weights Ω**		
Scenario	**Uncertain parameter #1:** Demand level	**Uncertain parameter #2:** DER uptake	**Weighting case #1**	**Weighting case #2**	**Weighting case #3**
#1	High demand	High uptake	16.6%	22.22%	11.11%
#2		Low uptake	16.6%	11.11%	22.22%

#3	Medium demand	High uptake	16.6%	22.22%	11.11%
#4		Low uptake	16.6%	11.11%	22.22%
#5	Low demand	High uptake	16.6%	22.22%	11.11%
#6		Low uptake	16.6%	11.11%	22.22%
			100%	**100%**	**100%**

Table 3 - Illustrative example for the weighting of scenarios across different cases

3.1.3 Module (C) - Market modelling / techno-economic assessment

The primary objective of this module is to simulate the operational behaviour of the distribution system throughout the analysis horizon, considering the implementation of each alternative (i.e. the candidate options produced in module A) designed to address the identified system need. These studies serve as a means to assess the technical viability and quantify the economic implications of each alternative across the range of scenarios developed in module B, ensuring compliance with relevant network standards and operational and market constraints.

Furthermore, this module facilitates the quantification of the costs, benefits and technical performance of each alternative. Overall, this module generates the following key outputs:

- Capital costs: Encompassing the costs associated with investments in network assets or the establishment of infrastructure necessary for the coordination of non-network solutions. The formulation of capital costs for each alternative must consider the lifespan of solutions to account for potential replacements required.
- Operational costs: Including costs related to energy imports, involuntary load shedding, customer DER curtailment, and other pertinent operational expenses.
- Technical system performance indicators: Including, but not limited to, lost load, voltage levels, DER curtailment, line loading, network losses. These provide insights into the technical performance of the system when considering the implementation of an alternative under various scenarios.

To generate these outcomes, this module allows the user to employ a range of sophisticated energy system optimisation or simulation tools, such as market optimisation models, optimal power flow (OPF) analysis, and other relevant analytical techniques. These mechanisms enable the detailed modelling of system operations, accounting for network constraints, market dynamics, and the operational characteristics of both network and non-network solutions. The outputs of this module, including both economic and technical indicators, are then utilised to calculate relevant economic indicators EI.

3.1.4 Module (D) - Selection and calculation of economic indicators

An **economic indicator,** denoted as $\mathrm{EI}_{a,s}$ is a quantitative metric employed to assess the performance of each feasible candidate alternative a within the system across multiple scenarios s and related sensitivities (those defined in module B).

This module entails the selection and calculation of appropriate economic indicators EI to assess each feasible candidate alternative a across the scenario set. The choice of an economic indicator is contingent upon factors such as:

- Data availability for its formulation, including capital and operational expenditure, as well as revenue streams. For instance, elaborating the net present cost (the economic indicator) would require data regarding investment costs and total system operational costs with a given alternative.
- The decision-maker's objectives, which may include cost minimisation, benefit maximisation, and risk mitigation, among others.
- The time horizon of the assessment and the discount rate applied. These may significantly influence the net present value and other time-sensitive economic indicators. The time horizon should align with the expected lifespan of the alternatives and the long-term planning objectives. The discount rate should reflect the risk associated with the cash flows and the opportunity cost of capital.

Table 4 provides a comprehensive, albeit non-exhaustive, list of economic indicators suitable for informing the decision-maker during the planning process.

Economic Indicator (EI)	**Symbol**	**Description**
Net present total system cost	NPC	Quantifies the total present cost of the system when introducing an alternative. Costs encompass both investment and operational expenditures, over the planning horizon.
Regret of net present total system cost	$\mathbb{R}(\mathrm{NPC})$	Quantifies the difference between an alternative's realised cost and the optimal cost achievable in hindsight. The regret represents the opportunity loss by not selecting the optimal alternative.
Weighted regret of net present total system cost	$\mathbb{R}(\mathrm{NPC},\Omega)$	The weighted regret quantifies the opportunity loss by not selecting the optimal alternative while factoring the likelihood of such regret actually materialising.
Net present value	NPV	Quantifies the present value of total benefits (difference in total costs) associated with an investment alternative relative to a *business-as-usual (do-nothing)*[5] case.
Cost of unserved energy	USE	Quantifies the potential economic costs related to energy not supplied throughout the planning horizon.
Customer curtailment cost	CECV	Quantifies the potential economic losses for customers due to curtailed DER over the planning horizon.
Internal rate of return	IRR	Determines the rate of return yielded by an investment alternative over the planning horizon.

[5] See section c. below for a thorough explanation about a *business-as-usual* case.

Discounted payback period	DPP	Calculates the number of periods required for an investment to recover its initial costs, accounting for the time value of money.

Table 4 - Possible economic indicators to inform the decision-maker

It is important to mention that multiple economic indicators can be selected to assess a set of candidate alternatives. Such an approach provides the decision-maker with a broader view of the implications of each alternative in terms of various indicators (i.e., a performance metric).

3.1.5 Module (E) - Selection and calculation of decision-making functionals

A **decision-making functional** is a fundamental element of the framework. Essentially, it is a mathematical operator, generically represented as $\Psi(\cdot)$, that aggregates the outcomes of an economic indicator $\mathrm{EI}_{a,s}$ across multiple scenarios (s), yielding a single representative number for each alternative (a) under evaluation. This consolidated number facilitates a comparative assessment of the alternatives, enabling informed decision-making. The selection of a specific decision-making functional for each economic indicator is contingent upon the decision-maker's risk tolerance, objectives, and the specific aims of the analysis.

It is crucial to recognise that different decision-making functionals embody distinct approaches to handling uncertainty and risk. For instance, some functionals may prioritise minimising potential losses (risk-averse), while others may focus on maximising expected benefits (risk-neutral or risk-seeking). Furthermore, the choice of functional may be influenced by the availability of information, and the prevailing regulatory environment. Table 5 summarises example functionals suitable for application within the decision-making process, highlighting their respective characteristics and potential implications.

Decision-making functional $\Psi(\mathrm{EI})$	**Description**	**Formulation** $\Psi(\mathrm{EI})$
Weighted mean	Calculates the expected value of the economic indicator, incorporating the scenario weightings established in Module E. This functional provides a probability-weighted average of outcomes across all scenarios.	$\mathbb{E}(\mathrm{EI},\Omega) = \sum_s \omega_s \cdot \mathrm{EI}_{a,s}$ • ω_s: Weight of scenario s • Ω: Set of weights
Worst-case outcome (maximum value)	Identifies the most adverse outcome within the set of scenarios, returning the maximum value of the economic indicator for each alternative a. This functional is particularly relevant for risk-averse decision-makers seeking to minimise potential losses, such as the maximum possible cost or regret.	$\max_s \mathrm{EI}_{a,s}$
Expected shortfall at a given percentage $(\mathrm{CVaR}_{\%})$	Determines the expected value of the economic indicator conditional on it exceeding (or falling below) a specific Value-at-Risk $(\mathrm{VaR}_{\%})$ threshold. This functional quantifies the expected loss in the tail of the distribution, providing a more comprehensive measure of extreme risk compared to VaR alone.	$\mathbb{E}[\mathrm{EI}_{a,s} \mid \mathrm{EI}_{a,s} \geq \mathrm{VaR}_{\%}]$

Table 5 - Possible functionals to incorporate in the decision-making process

3.1.6 Module (F) - Selection of decision-making criterion

This module facilitates the final selection and ranking of investment alternatives. By applying an appropriate decision-making criterion, the planner can identify the most suitable planning alternative.

The primary objective of a **decision-making criterion** is to provide a recommendation based on the outcomes generated by a decision-making functional (defined in Module E), given a set of candidate alternatives. Hence, a decision criterion serves to identify the alternative that achieves either the minimum (e.g., in terms of expected costs or regrets) or the maximum (e.g., in terms of expected benefits) value. Table 6 details the application context for each criterion.

Decision-making criterion	Description
Minimisation of the objective $\mathrm{argmin}_{a\in\mathcal{A}}\Psi(\mathrm{EI})$	To rank and determine the alternative $a \in \mathcal{A}$ capable of **minimising** the decision-making functional $\Psi(\cdot)$ applied to economic indicator EI.
Maximisation of the objective $\mathrm{argmax}_{a\in\mathcal{A}}\Psi(\mathrm{EI})$	To rank and determine the alternative $a \in \mathcal{A}$ capable of **maximising** the decision-making functional $\Psi(\cdot)$ applied to economic indicator EI.

Table 6 - Context and application of decision-making criterion

Consequently, for each assessment case employing a distinct economic indicator (Module D) and/or decision-making functional (Module E), the decision-making criterion must be selected in a coherent manner with those choices. Table 7 outlines examples of coherent pairings.

Reasonable pairing example	Economic Indicator EI	Decision-making functional $\Psi(\mathrm{EI})$	Decision-making criterion	Description
#1 **Minimisation of cost**	Net present costs (NPC)	Scenario-weighted mean	$\mathrm{argmin}_{a\in\mathcal{A}}\mathbb{E}(\mathrm{NPC})$	The decision-maker would seek for the alternative(s) capable of minimising the scenario-weighted mean of net present costs.
#2 **Minimisation of regret (risks)**	Regret of net present costs $(\mathbb{R}^{\mathrm{NPC}})$	Worst outcome $(\max)$	$\mathrm{argmin}_{a\in\mathcal{A}} \max \mathbb{R}(\mathrm{NPC})$	The decision maker would seek for the alternative(s) capable of minimising the worst (maximum) regret in terms of net present costs.
#3 **Maximisation of benefits**	Net present value (NPV)	Scenario-weighted mean	$\mathrm{argmax}_{a\in\mathcal{A}}\mathbb{E}(\mathrm{NPV})$	The decision-maker would seek for the alternative(s) capable of maximising the scenario-weighted mean of net present value (benefits).
#4 **Minimisation of expected worst-case cost**	Net present costs (NPC)	Expected shortfall at 5% $(\mathrm{CVaR}_{95\%})$	$\mathrm{argmin}_{a\in\mathcal{A}}\mathrm{CVaR}_{95\%}(\mathrm{NPC})$	The decision-maker would seek for the alternative(s) capable of minimising the weighted mean of the 5% scenarios with highest net present costs.

Table 7 - Examples of reasonable pairings between economic indicator, decision-making functional and decision-making criterion

3.1.7 Module (G) - Robustness assessment

Following the selection of a preferred investment alternative, it is imperative to conduct a rigorous robustness assessment to evaluate the sensitivity of a decision to underlying assumptions. This module aims for the systematic testing of these assumptions, particularly through scenario re-weighting, to determine whether the optimal decision remains consistent under variations in scenario likelihoods.

Specifically, this module leverages the set of scenario weightings developed in Module B to examine potential shifts in optimal decisions arising from variations in scenario likelihoods. This involves systematically testing the weights assigned to different scenarios and observing the resulting changes in the ranked order of alternatives.

Furthermore, this module extends beyond merely assessing the stability of the ranking. It also involves evaluating the potential economic consequences of deviations from the assumed scenario probabilities. This includes quantifying the potential losses or gains associated with each alternative under different weighting scenarios, thereby providing a more comprehensive understanding of the risk-return trade-offs. The robustness assessment serves several critical functions:

- Validation and decision stability: It allows ensuring that the preferred alternative remains optimal across a range of plausible scenarios and probability weightings.
- Identification of critical assumptions: It highlights the assumptions that exert the most significant influence on the decision, enabling focused attention on these areas.
- Quantification of decision risk: It provides a quantitative measure of the potential economic consequences of uncertainty (via the scenarios considered), facilitating informed risk management.
- Enhancement of decision confidence: By demonstrating the *resilience* of the decision to variations in assumptions, it strengthens confidence in the investment choice.

In addition, this multi-criteria approach allows for assessment strategies tailored to the planner's preferences, for example, through hierarchical evaluations where only alternatives that meet predefined thresholds progress to subsequent evaluation layers. Planners can also assign relative weights to decision criteria, reflecting their significance in the context of specific planning objectives. Moreover, the stability of an alternative's performance across decision criteria can be assessed, potentially favouring options with lower variability, even if they do not exhibit the highest performance in individual metrics.

In essence, by ensuring robustness, this module enhances the credibility and reliability of investment decisions in the face of real-world uncertainty, contributing to more informed distribution system planning.

3.2 Additional considerations

3.2.1 Real-world applicability of the framework

- The proposed decision-making framework is adaptable for planning at any network level (high, medium or low voltage). It allows for the assessment of investment alternatives and scenario sets of any scale.
- The modular architecture of the framework facilitates efficient parallel work. Different teams within an organisation can independently generate the necessary data and perform respective calculations for each module, ensuring both autonomy and seamless integration when required.
- The framework is engineered for a quick and straightforward material implementation. Once the economic indicator matrices (alternatives across scenarios) are generated in Module D, the subsequent analysis, encompassing weighting and the derivation of recommendations, can be efficiently executed using readily available spreadsheet software such as Microsoft Excel or Google Sheets.
- Once the methodological framework is in place, a large number of scenarios and planning alternatives can be evaluated at scale. This enables the potential automation of the process, reducing it to the generation of system-wide investment and operational costs (via any suitable modelling engine) and the automated population of results into structured databases (Microsoft Excel or Google Sheets).

3.2.2 Definition of a business-as-usual (do-nothing) case

A fundamental component of the analysis associated with the proposed decision-making framework is the establishment of a baseline case, commonly referred to as the *'business-as-usual'* case (in the context of this methodological design, understandable as a *do-nothing* approach, where no investment measures of any kind are taken).

This baseline case aims to measure the technical performance and economic results of the distribution system under anticipated operating conditions **without implementing any credible investment alternatives identified** in Module A to address the defined system need. It represents the system's performance in the absence of any alternative designed to handle the identified need.

Specifically, the *business-as-usual (do-nothing)* case serves to quantify the incremental benefits derived from the implementation of each alternative a across the range of scenarios $s \in \mathcal{S}$. It provides a benchmark against which the potential technical and economic improvements resulting from the introduction of an alternative can be assessed. These improvements may include, but are not limited to, reductions in imported energy, DER curtailment, unserved energy as well as total costs.

3.2.3 Selection of the most preferred alternatives

A significant advantage of this methodological approach lies in its capacity to facilitate robust **multi-scenario** and **multi-criteria analysis**, enabling the identification of the most favourable investment alternatives for the distribution system across many potential future states of the system while utilising different criteria to perform a comprehensive assessment. This capability is substantiated by the framework's flexibility, as demonstrated in Table 7, which shows how diverse combinations of economic indicators, decision-making functionals and criteria can be selected to align with the decision-maker's specific objectives.

Consequently, each unique combination of economic indicator, decision-making functional, and criterion could yield an **actionable investment recommendation** derived from the uncertainty-aware decision-making process. Figure 5 provides an illustrative example of the interactions between these modules and their role in informing the decision-maker.

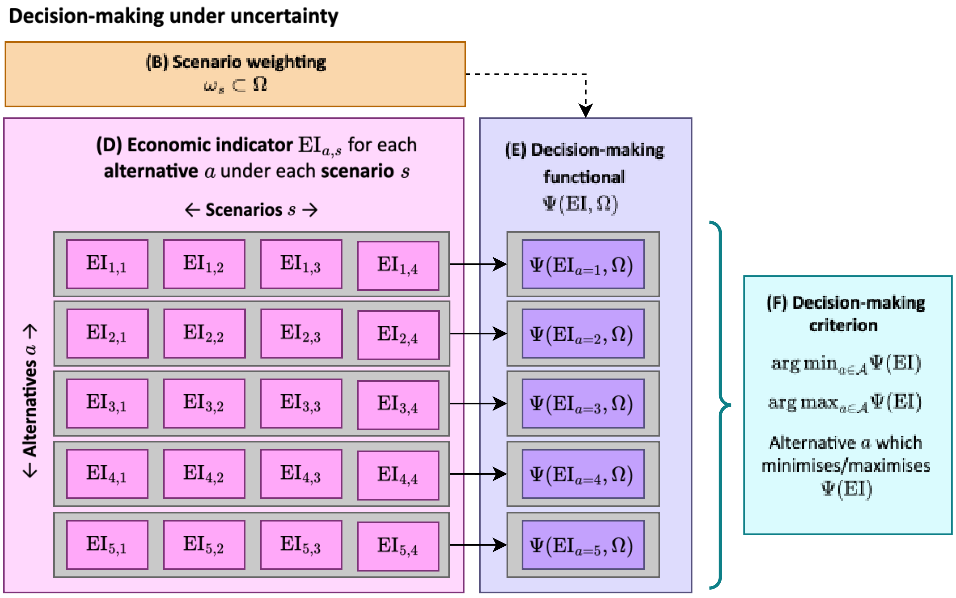


Figure 5 - Example of the process for decision-making under uncertainty considering five possible alternatives and four scenarios

- In this example, the analysis encompasses **five investment alternatives** and **four scenarios**. Following the market/techno-economic assessment (Module C), an instance of the selected economic indicator (Module D), $\mathrm{EI}_{a,s}$, is generated for each alternative and scenario. Essentially, when considering all instances of an economic indicator, a **matrix** (with dimensions of alternatives × scenarios) is generated, enabling a transparent understanding of the results.
- In this case, for each of the five alternative (rows), four distinct instances of the economic indicator are obtained, corresponding to each scenario (columns). This can be conceptualised as a four-dimensional vector, EI_a for each alternative.
- In module E, the decision-making functional Ψ is then applied to each vector EI_a, performing a consistent mathematical operation that yields a single, unidimensional value for each alternative, informing the final decision (as illustrated in module E of Figure 5).
- Through Module F, the decision-maker would typically select the alternative a that minimises or maximises the output of the decision-making functional, depending on the chosen criterion.

This assessment process can be conducted **iteratively** for any economic indicator, decision-making functional and criterion, **establishing a combined analysis that can inform planners about cost,**

benefits and planning risks when selecting adequate metrics. Moreover, given a decision over a specific criterion, it is possible to re-assess that decision against another criterion. This would reveal potential planner risks the planner might commit to.

3.3 Illustrative case studies

To illustrate the application of the framework and methodology, two case studies using a sample illustrative sub-transmission network and a real-life sub-transmission network topology from WP1.4 were used. Details of the case study for a real-life sub-transmission network topology can be found in Appendix Three of this summary report. Details of the case study using a sample sub-transmission network can be found in the research report[6].

[6] Techno-Economic Modelling of Non-Network Solutions (WP 2.9), Section 4, starting on page 32

4. Observations, insights and key reflections for stakeholders

Through the evaluation of the work undertaken, C4NET has identified some observations, insights and key reflections for stakeholders. Outlined below we have summarised these for DNSPs, AEMO, policy makers and researchers, with a section highlighting observations in relation to consumer outcomes. While these are summarised for stakeholder type, this section should be read as a whole to ensure cross-sectoral awareness.

4.1 DNSPs

Distribution systems in Australia are undergoing a profound transformation, characterised by the rapid uptake of consumer energy resources (CER) and distributed energy resources (DER) and increasing electrification across various energy consumption sectors. This dynamic landscape introduces significant uncertainties into the planning of the network, posing substantial risks of under or over investment in long-life network assets, which ultimately leads to increased costs for consumers. Figure 6 illustrates uncertainties surrounding modern distribution systems in the State of Victoria, Australia[7].

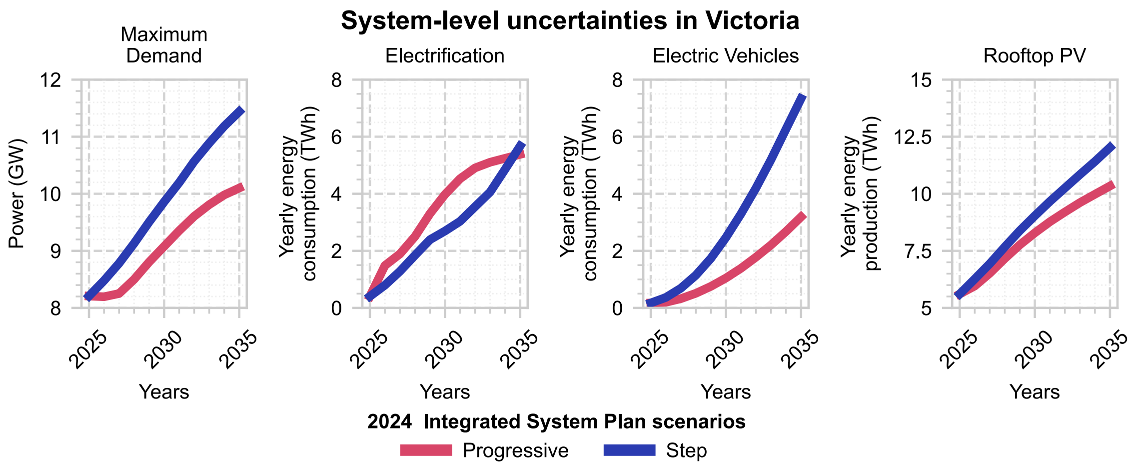


Figure 6: Distribution system-related uncertainties in the State of Victoria, Australia

Single-scenario network planning approaches[8] are increasingly challenged while navigating this complexity, potentially leading to inefficient planning decisions. This is often due to a failure to adequately recognise the significant impacts of uncertainty and an underestimation of the optionality offered by DER-based, non-network alternatives, which can provide adaptive "compromise solutions" for managing planning uncertainties.

[7] Elaborated with data sourced from AEMO 2024 ISP: https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

[8] A single-scenario approach in network planning usually relies on a unique scenario forecast (typically of demand growth) to guide investment decisions. Subsequently, identified needs are primarily addressed through conventional network augmentations, such as line reconductoring or transformer upgrades.

This research project has set out to address three fundamental questions to improve the consideration of DER-based, non-network solutions, by DNSPs in their planning approach:

- *What methodological considerations are necessary to gauge the value brought by non-network alternatives in a context of uncertainty in distribution system planning?*
- *How could demand-side management or more in general, non-network options stack up well against traditional augmentations?*
- *What are the appropriate approaches to handle and disclose planning risks associated with inefficient investment decisions in a context where various options are simultaneously assessed?*

The proposed framework and methodology offer several key advantages for DNSPs, particularly in navigating uncertainties, planning risks and facilitating informed investment decisions:

- **Robust decision-making under uncertainty:** The framework's core strength lies in its systematic approach to handling the significant uncertainties inherent in modern distribution system planning (e.g., DER adoption, electrification, load growth) through rigorous multi-scenario analysis and informed scenario weighting. This enables DNSPs to move beyond single-scenario planning, leading to investment decisions that are demonstrably more adaptable to a wider range of plausible future system states,
- **Comprehensive multi-criteria assessment:** By employing a comprehensive suite of economic indicators, decision-making functionals, and decision criteria, the framework facilitates a thorough and transparent evaluation of investment alternatives. Such assessment can reveal critical trade-offs between cost, risk, and various benefits (e.g., reduced curtailment), empowering stakeholders with a richer understanding of the implications of each choice and fostering more informed, value-driven decisions.
- **Quantification of planning risks:** The methodology provides a powerful capability for the explicit quantification of potential planning risks associated with choosing different alternatives under various criterion. By understanding the regret of a suboptimal planning decision, stakeholders can proactively identify and mitigate potential downsides, leading to more risk-aware investment strategies and a greater degree of confidence in long-term planning outcomes.
- **Identification of robust and balanced solutions:** The framework facilitates the identification of investment alternatives that demonstrate consistent and robust performance across a spectrum of plausible future scenarios and evaluation criterion. This is particularly valuable for stakeholders seeking balanced solutions that offer a good compromise across competing objectives and varying levels of uncertainty,
- **Value of non-network solutions:** The framework provides a structured and transparent methodology for determining the potential economic value and developing appropriate remuneration schemes for non-network solutions (e.g., battery storage, demand response).

For example, by comparing their benefits (such as avoided network augmentation) against traditional infrastructure investments, the framework empowers stakeholders to strategically integrate non-network options into their long-term plans, optimising capital expenditure.

- **Practicality:** As the proposed framework is based on modular architecture, it facilitates efficient collaboration and parallel work streams of teams within an organisation. It can be adapted across all network voltage levels and be scaled to various project sizes. Automating some analytical steps by leveraging standard spreadsheet software reduces resource requirement.

For the proposed planning framework to be adopted, it is important that stakeholder discussions and agreements are reached regarding the key inputs used, as these can materially influence the outcomes of the assessment. For example, this would include scenario assumptions and parameters, and their consistency across the various solutions being considered, as well as the uncertainties to be considered and what weightings are to be used for various scenarios.

4.2 AEMO

While the proposed framework is directed towards DNSP planning activities, the theory behind the framework can be leveraged by AEMO in its planning of the transmission networks. In addition, as Victorian DNSPs are responsible for the augmentation planning of the connection assets at terminal stations, AEMO's involvement and endorsement of the planning framework will be important to facilitate whole-of-system planning.

4.3 Policy makers

Other ESP projects have confirmed the mammoth challenge faced by the electricity distribution industry to accommodate the forecast increase in the connection of CER/DER and the increased peak consumption from gas electrification. This project has proposed an enhanced planning framework that could turn the challenge caused by CER/DER into an opportunity, by valuing CER/DER as non-network solutions (NNS) to address network constraints.

Adopting the methodological principles outlined in this project could support a more standardised and strategic approach to formulating and further assessing investment plans. This approach can facilitate the integration and more effective consideration of flexible demand-side resources by transparently quantifying planning risks and identifying robust, balanced solutions.

It is recommended that policy makers be involved in the standardisation process for the implementation of this enhanced planning framework across Australia. This will provide certainty and transparency for DNSP investment decisions, and signal to prospective NNS providers that their offerings will be fairly and transparently treated in augmentation investment decision making. In addition, policy makers can play a significant role in facilitating the development of a NNS market.

4.4 Consumer

Customers should be informed of the opportunity to support the distribution systems through flexibility mechanisms under the enhanced planning framework. By extension, the decision-theory based NNS valuation approach could provide a transparent mechanism for NNS service providers to formulate CER benefits/rewards for individual consumers who chose to participate in the solutions.

4.5 Research

The proposed planning framework is comprehensive but may appear to be daunting at first thought. As pointed out in the research report, there exists opportunity to automate some key steps of the process using standard data analysis tools. This can be a further research direction which will assist in the smooth uptake of the planning framework. To achieve this, researchers will need to work closely with DNSPs, AEMO and other stakeholders.

Appendix One

Researcher profile

Conducted by: University of Melbourne, Melbourne

Lead Researcher:	Pablo Apablaza
Research Team:	Cristian Alcarruz, Prof. Pierluigi Mancarella

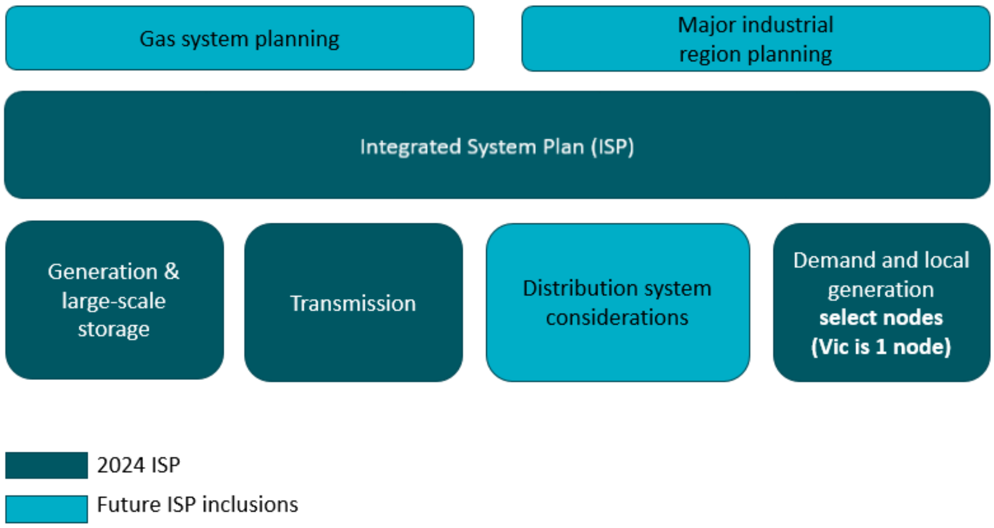
About C4NET

C4NET delivers multi-disciplinary solutions to the challenges the energy industry is facing. Working with complexity requires diverse skills, reliable data and new approaches, which C4NET facilitates by bringing together governments, industry and universities, creating new links across the sector.

Central to C4NET's program of work is the Enhanced System Planning (ESP) project, a significant and collaborative research project aimed at informing sub transmission level electricity planning beyond 2030, with a focus on building methodologies and approaches for bottom-up modelling and to highlight the opportunities presented through the distribution system and integrating Consumer Energy Resources (CER), to inform whole of system planning.

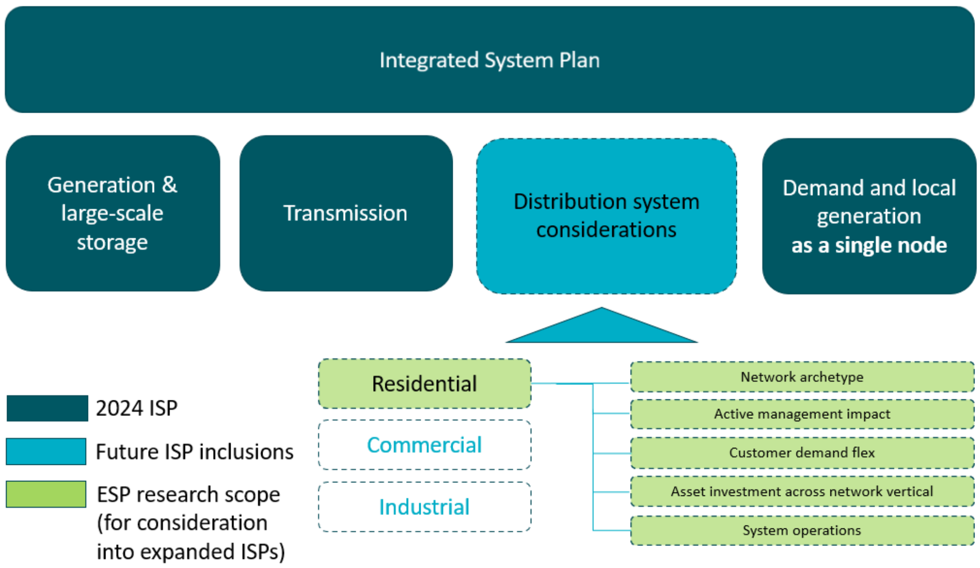
Appendix Two – Bigger picture integration with the ISP

Shift towards whole of system planning



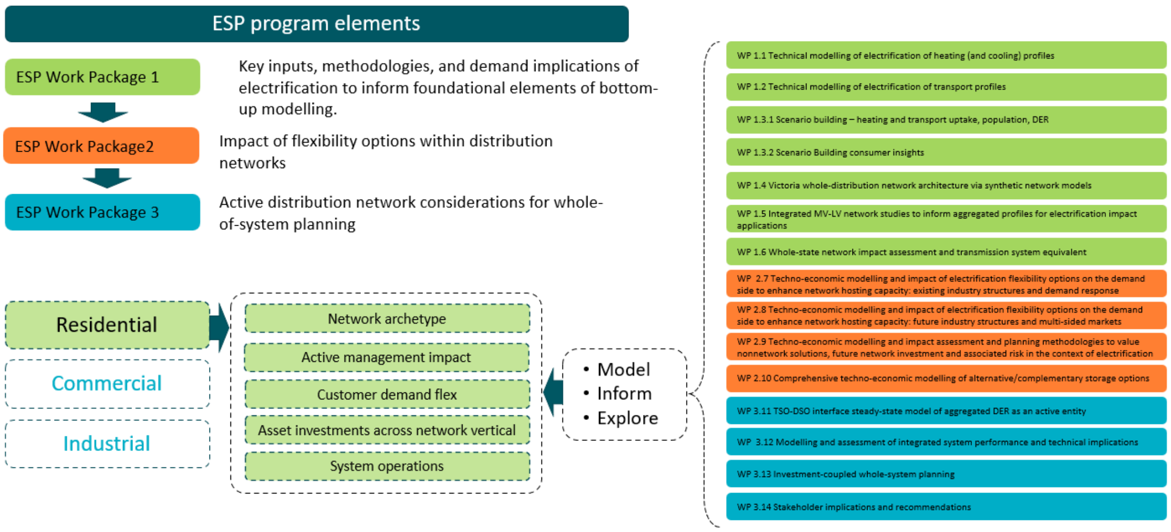
The Energy and Climate Change Ministerial Council (ECMC) accepted the recommendations of the review of the ISP which target transformation of the energy system as a whole, with particular reference to gas system planning, major industrial region planning and distribution systems.

Distribution system components of whole of system planning

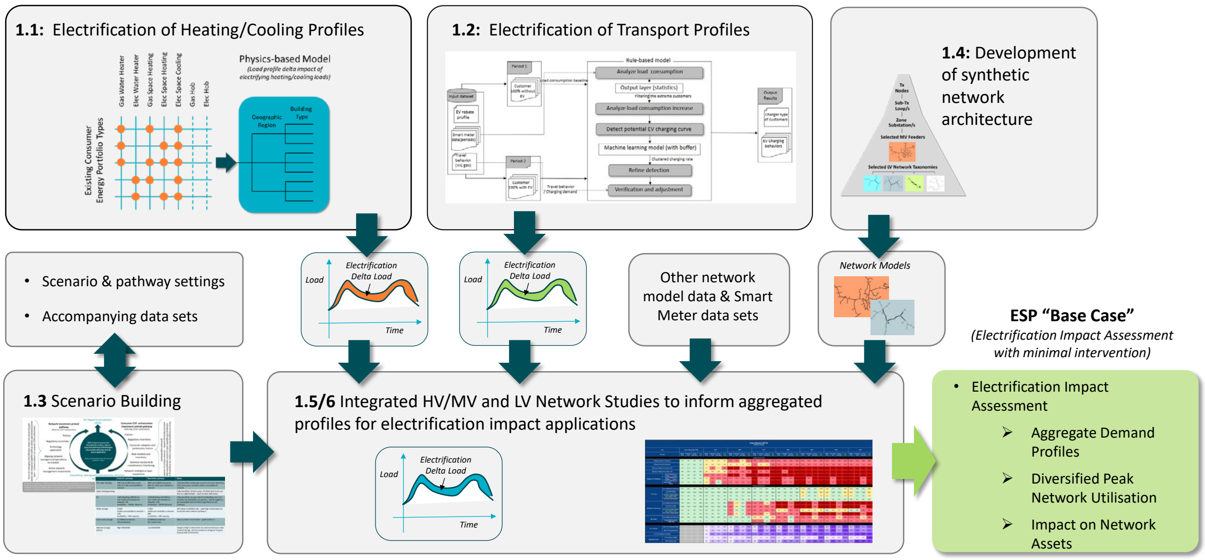


The ESP was scoped to be deliverable with the resources and time at hand to inform feasibility of broader application. It focussed on the more complex areas around residential and low voltage assets of the distribution system, with an application across Victorian networks with methodologies applicable to any region in the NEM.

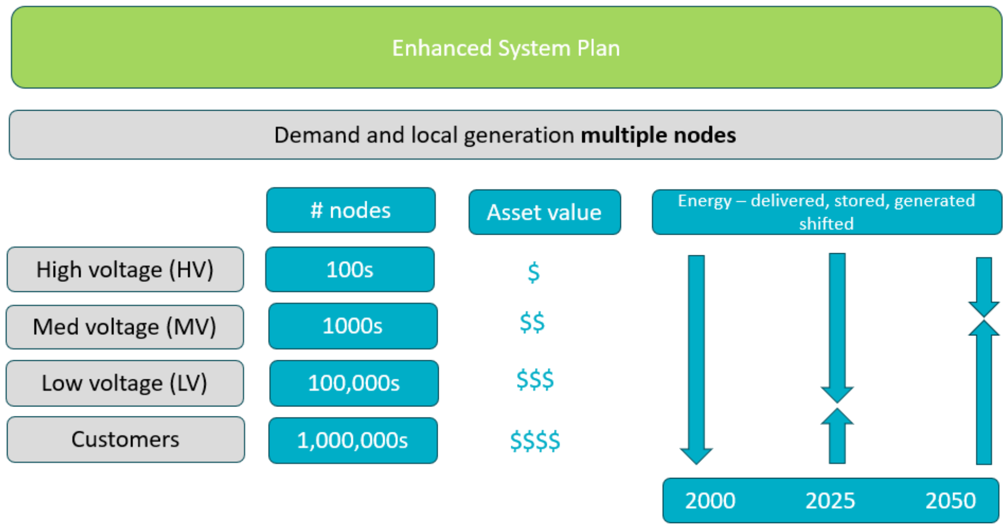
ESP alignment with distribution system components of whole of system planning



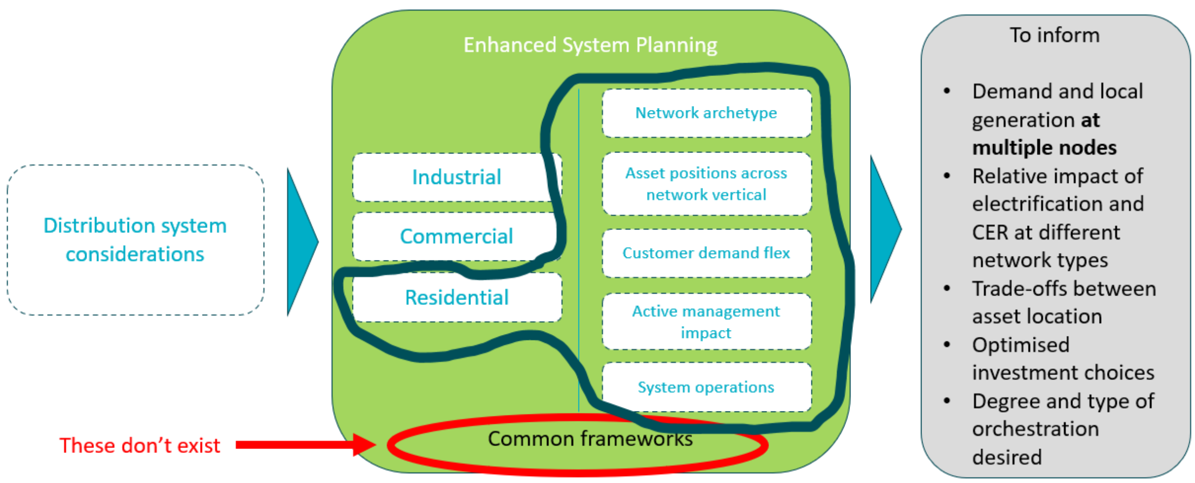
The 'base case' for residential electrification impact assessment, the flex options and relativity to other investment options



Elements needed to meaningfully inform distribution system aspects in whole of system planning



Methodological gaps in whole of system planning



Appendix Three – Case study using a real-life sub-transmission network

Victorian case study to assess demand-side flexibility in distribution networks – Cranbourne Terminal Station (CBTS)

The case study shows the applicability of the proposed framework to assess the benefits of electrification of different demand sectors as a means of providing operational flexibility to the system via centralised control. For this purpose, the CBTS (Cranbourne Terminal Station) network model is employed. A significant portion of the input data used in this analysis was sourced from other WPs within the ESP project. Specifically, the network models were derived from the outputs of WP1.4, while the electrification and storage profiles were obtained from WP2.10. It is important to note that although this case study is based on real network models, **the numerical results are for illustrative purposes only.**

Setup of the case study

This case study uses the CBTS network described in Figure A3.1, Tables A3.1 & A3.2. A ten-year planning horizon, beginning in 2040, is selected to align with the minimum planning horizon required by the NER.

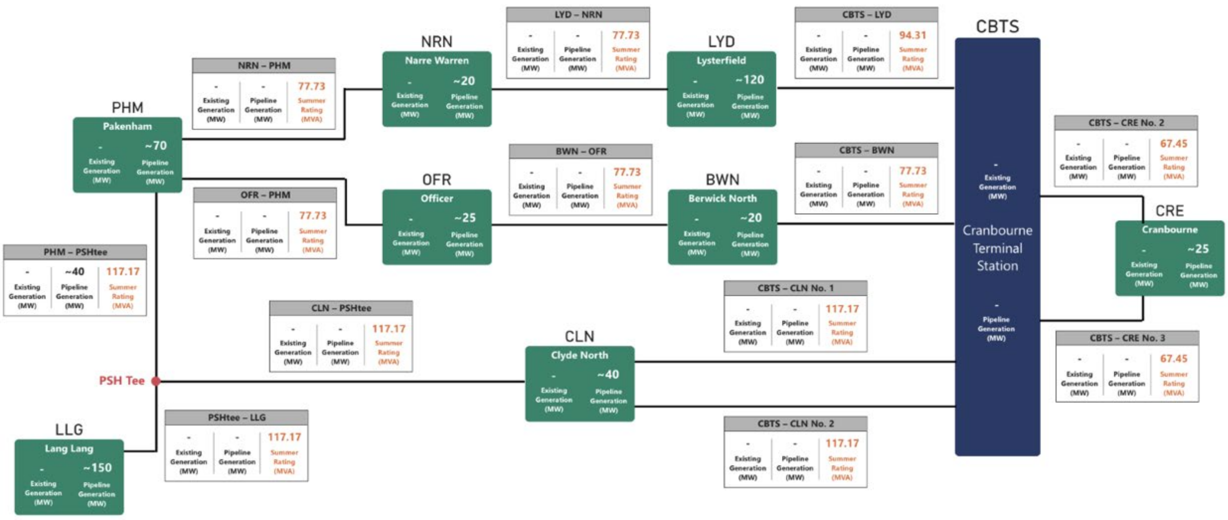


Figure A3.1 - Cranbourne Terminal Station (CBTS) network model

The CBTS sub-transmission network is characterised with a rooftop PV installed capacity and a peak demand according to Table A3.1. In addition, each network is composed by a set of zone substations, which are formed by a combination of MV-LV typical feeders, either urban, suburban, short rural and/or long rural (obtained as a result from WP 1.4). The network composition is presented in Table A3.2.

Sub-transmission network	Peak load (MW)	Rooftop PV capacity (MW)
CBTS	471.30	354.34

Table A3.1 - Rooftop PV capacity and peak demand for CBTS sub-transmission network, base year 2024.

Sub-transmission network	Zone substation symbol	Zone substation name	Postcodes	Clients	Urban	Suburban	Short rural	Long rural
CBTS	CRE	Cranbourne	3977	23,325	4	0	2	0
	LYD	Lysterfield	3156	7,524	2	0	2	0
	BWN	Berwick North	3806	9,009	3	0	1	0
	NRN	Narre Warren	3804, 3805	6,338	4	0	1	0
	OFR	Officer	3809	22,521	2	0	1	1
	CLN	Clyde North	3978	35,625	4	0	4	0
	PHM	Pakenham	3810	16,112	4	0	4	0
	LLG	Lang Lang	3984	7,083	4	0	2	0

Table A3.2 - Zone substation composition for CBTS sub-transmission network

Identification of system needs

With the increasing electrification of various energy consumption sectors in Victoria, Australia, significant opportunities are emerging to enhance the operation of distribution systems. Sectors such as transport (through electric vehicles), domestic hot water, and heating and cooling offer considerable potential as their electrification accelerates, while complemented by the growing penetration of distributed battery storage in distribution networks. These developments could enable more flexible power exchanges, which can deliver significant benefits, including reduced reliance on energy imports and decreased curtailment due to higher levels of storage available. However, unlocking demand-side flexibility from an operational perspective entails costs, as it requires enabling infrastructure and supporting technologies. It is therefore essential for planners to quantify the potential techno-economic benefits of electrifying and centrally controlling different demand sectors in order to assess trade-offs between costs and enabling flexibility. Achieving this requires a comprehensive assessment using a range of indicators and evaluation criteria to strategically guide decision-making and inform stakeholders.

Elaborating a set of feasible alternatives

The alternatives of coordination are presented in A3.3. It is important to mention that in these options; network reinforcements are also considered as a means to keep the technical constraints of the system within its limits.

Set of alternatives to address the identified system need			
ID	**Alternative**	**Technical characteristics**	**Estimated capital / coordination cost**
1	*Network augmentation*	All aluminum conductor (AAC)	$ 11,437/km/MVA
2	*Controllability* Domestic hot water (DHW)	Centralised control of electricity demand for domestic hot water	$ 2,000 – 12,000/MW (coordination costs)
3	*Controllability* Heating and cooling (H&C)	Centralised control of electricity demand for heating and cooling purposes	$ 2,000 – 12,000/MW (coordination costs)
4	*Controllability* Electric vehicles (EV)	Centralised control of charging and discharging of electric vehicles storage	$ 2,000 – 12,000/MW (coordination costs)
5	*Controllability* Distributed battery storage	Centralised control of charging and discharging of distributed battery storage systems	$ 2,000 – 12,000/MW (coordination costs)

Table A3.3 - Set of alternatives for the CBTS sub-transmission network case study application.

Scenario design to address uncertainties and risks – Application of Module (B)

In addition to the screening of reasonable alternatives, the planner must take care of developing different plausible scenarios regarding the evolution of the system with respect to parameters with significant uncertainty. As described in module B, the development of scenarios can be also informed by information provided by external parties. An example is the trends seen in AEMO's ISP for different scenarios.

For this case study, uncertainty is considered in two critical parameters: *demand growth* and *adoption of DER (rooftop PV generation)*. The growth trends with uncertainty considered for the analysis correspond to the *Step* and *Progressive* scenarios of the 2024 ISP, which are illustrated in Figure A3.2. It is important to mention that the scenarios designed for this case study do not incorporate the absolute capacities shown, but rather the relative growth trends between each year.

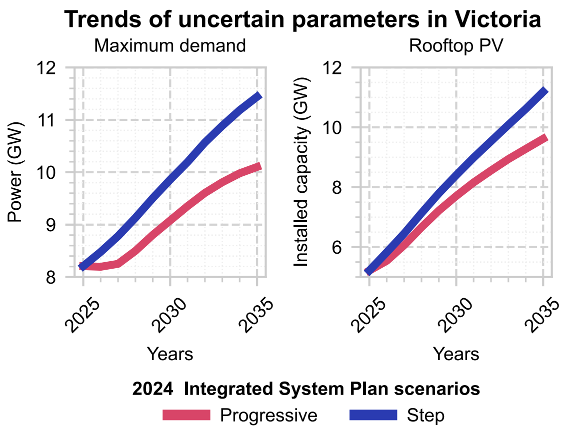


Figure A3.2 - Trends for the scenarios considered in the illustrative case study application.

For a more detailed evaluation of investment alternatives, the planning analysis can be refined by considering intermediate years within the defined planning horizon. This enables the development of incremental "transition" scenarios, offering a higher fidelity representation of the unfolding of uncertainties over time. Figure A3.3 provides a visual explanation of the logic underpinning this incremental scenario-transition approach.

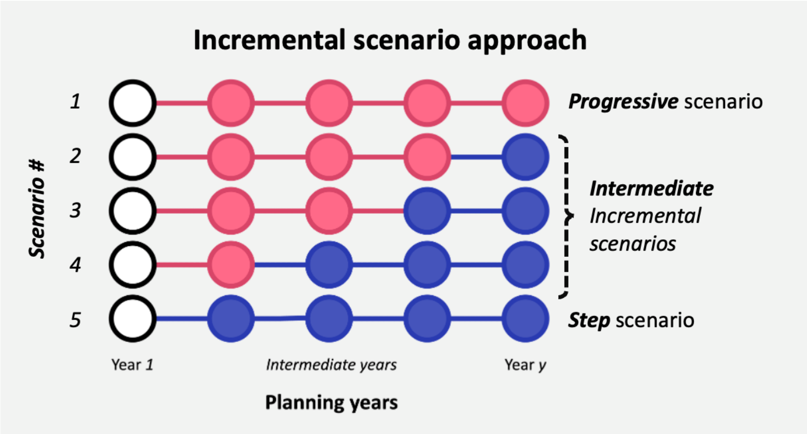


Figure A3.3 - Design of scenarios to incorporate intermediate years with potential transitions in between.

To account for specific risks identified by the planner, the scenario set is expanded with parametric variations. For this case study, the considered the risks are a *reduced DER available capacity* as well as *increased capital costs,* which affect network options. To model the potential impact of each risk, variations are applied to the original scenarios, representing potentially detrimental conditions even if their likelihood is low. The resulting scenario set includes:

- **Base conditions:** No variation in the scenarios due to specific risks.
- **Risk - Low DER availability:** In all scenarios, the availability of DER (non-network options) can only provide up to 50% of the originally expected capacity.
- **Risk - Very low DER availability:** In all scenarios, the availability of DER (non-network options) can provide up to 25% of the originally expected capacity.
- **Risk – Supply chain and social licence:** Capital costs of network augmentation increase by up to 50% and lead times extended are extended by one more year.

Table A3.4 summarises all the scenarios and weights ω_s considered for this particular case study.

Base conditions		Low DER availability		Very low DER availability		Supply chain and social licence	
Scenario N°	Weight ω_s	Scenario N°	Weight ω_s	Scenario N°	Weight ω_s	Scenario N°	Weight ω_s
1	14.3%	6	1.4%	11	1.4%	16	2.9%
2	14.3%	7	1.4%	12	1.4%	17	2.9%
3	14.3%	8	1.4%	13	1.4%	18	2.9%
4	14.3%	9	1.4%	14	1.4%	19	2.9%
5	14.3%	10	1.4%	15	1.4%	20	2.9%

Table A3.4 - Scenarios designed for the illustrative case study application.

Market modelling/techno-economic analysis – Application of Module (C)

Once the *set of candidate alternatives* $\mathcal{A}$ (output of module A) and the *set of scenarios* $\mathcal{S}$ (output of module B) are defined, the next step is the techno-economic evaluation of the distribution system. This involves assessing how the system performs with each alternative implemented under each scenario, ensuring it meets all relevant network standards and operational constraints.

The techno-economic analysis provides the necessary information for calculating every economic indicator (EI) used in the multi-criteria assessment. For this case study, each alternative (listed in Table A3.3) was evaluated across every scenario using optimal power flow (OPF) analysis. Figure A3.4 shows the constraints included in this model and the relevant outputs it produced.

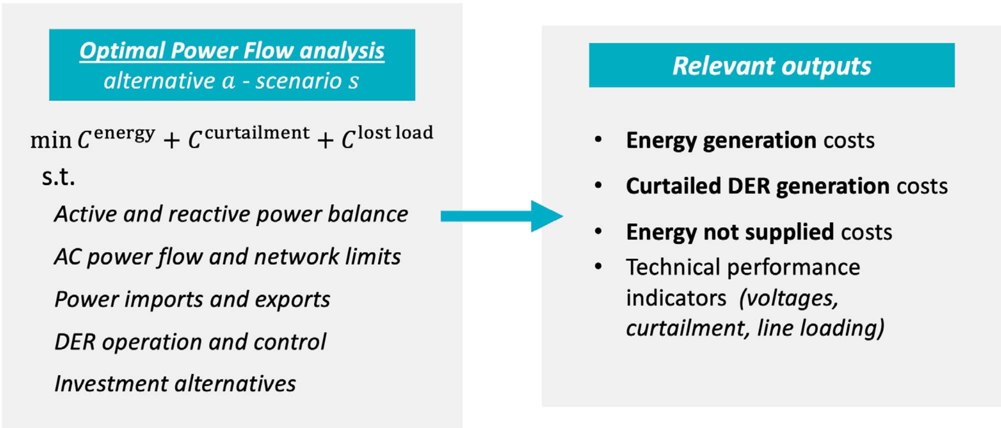


Figure A3.4 - Optimal power flow constraints for techno-economic analysis of alternatives and relevant outputs.

Multi-criteria assessment of demand-side controllability

As highlighted in previous sections, the multi-criteria assessment of alternatives across multiple scenarios requires following structured methodological steps to generate meaningful insights for decision-making. The process involves steps such as (a) conducting a techno-economic analysis (implemented here through optimal power flow simulations) for each alternative under evaluation across all scenarios; (b) deriving the relevant economic indicators; (c) calculating decision-making functionals; and (d) identifying the preferred alternatives based on defined decision criteria.

Table A3.5 presents the economic indicators used in this case study. Subsequently, Table A3.6 summarises the results of the decision-making functionals and the direct application of the decision criteria, ultimately highlighting the preferred alternative in each case. It is important to note that the selection between alternatives is heavily influenced by assumptions regarding available capacity in the network and the input data underlying each electrification profile, elements that are beyond the scope of this work package.

To conclude, Figure A3.5 offers a comprehensive visual summary of the preferences and rankings of each alternative. This figure illustrates the strong potential of transport electrification (via electric vehicles) and distributed storage as controllable technologies in order to provide flexibility for the network under study. Overall, the approach enables a transparent review of how each decision is shaped, ranked, and justified, thereby elucidating the planning risks associated with selecting one alternative over another.

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ECONOMIC INDICATOR MATRICES

(1) Net present cost

ECONOMIC INDICATOR (EI) →		TOTAL SYSTEM NET PRESENT COST (NPC) - $M AUD																			
↓ ALTERNATIVES ↑	#1 **Network reinforcement (NR)**	1098	1170	1227	1293	1307	1098	1170	1227	1293	1307	1098	1170	1227	1293	1307	1809	1880	1935	2000	2012
	#2 **NR + Controllability** *Heating and Cooling (H&C)*	1002	1074	1130	1197	1211	1050	1122	1179	1245	1259	1074	1146	1203	1269	1283	1736	1807	1863	1927	1940
	#3 **NR + Controllability** *Domestic hot water (DHW)*	1082	1154	1210	1277	1291	1090	1162	1218	1285	1299	1094	1166	1222	1289	1303	1788	1859	1914	1980	1993
	#4 **NR + Controllability** *Electric Vehicles (EV)*	909	982	1038	1105	1118	1003	1075	1132	1199	1212	1051	1123	1179	1246	1260	1611	1682	1737	1803	1814
	#5 **NR + Controllability** *Distributed BESS*	981	1054	1110	1177	1191	991	1063	1120	1186	1200	1005	1077	1134	1201	1215	1681	1751	1807	1873	1885
SCENARIO NUMBER →		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
RISKS →		*BASE CONDITIONS*					*LOW DER 50% AVAILABLE CAPACITY*					*LOW DER 25% AVAILABLE CAPACITY*					*SUPPLY CHAIN ISSUES*				

(2) Regret of net present cost

ECONOMIC INDICATOR (EI) →		REGRET OF NET PRESENT TOTAL SYSTEM COSTS - ($M AUD)																			
↓ ALTERNATIVES ↑	#1 **Network reinforcement (NR)**	189	189	189	189	189	107	107	107	107	107	93	93	93	93	92	197	197	198	197	198
	#2 **NR + Controllability** *Heating and Cooling (H&C)*	93	93	93	93	93	59	59	59	59	59	69	69	69	68	68	125	125	125	124	126
	#3 **NR + Controllability** *Domestic hot water (DHW)*	172	172	172	172	172	99	99	99	99	99	89	89	89	88	88	176	176	177	177	178
	#4 **NR + Controllability** *Electric Vehicles (EV)*	0	0	0	0	0	13	12	12	12	12	46	45	45	45	45	0	0	0	0	0
	#5 **NR + Controllability** *Distributed BESS*	72	72	72	72	72	0	0	0	0	0	0	0	0	0	0	69	69	70	69	70
SCENARIO NUMBER →		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
RISKS →		*BASE CONDITIONS*					*LOW DER 50% AVAILABLE CAPACITY*					*LOW DER 25% AVAILABLE CAPACITY*					*SUPPLY CHAIN ISSUES*				

(3) Weighted regret of net present cost

ECONOMIC INDICATOR (EI) →		SCENARIO-WEIGHTED REGRET OF NET PRESENT COSTS - ($M AUD)																			
↓ ALTERNATIVES ↑	#1 **Network reinforcement (NR)**	27	27	27	27	27	2	2	2	2	2	1	1	1	1	1	6	6	6	6	6
	#2 **NR + Controllability** *Heating and Cooling (H&C)*	13	13	13	13	13	1	1	1	1	1	1	1	1	1	1	4	4	4	4	4
	#3 **NR + Controllability** *Domestic hot water (DHW)*	25	25	25	25	25	1	1	1	1	1	1	1	1	1	1	5	5	5	5	5
	#4 **NR + Controllability** *Electric Vehicles (EV)*	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	0
	#5 **NR + Controllability** *Distributed BESS*	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	2	2	2	2	2
SCENARIO WEIGHTS →		14.3%	14.3%	14.3%	14.3%	14.3%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	2.9%	2.9%	2.9%	2.9%	2.9%
SCENARIO NUMBER →		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
RISKS →		*BASE CONDITIONS*					*LOW DER 50% AVAILABLE CAPACITY*					*LOW DER 25% AVAILABLE CAPACITY*					*SUPPLY CHAIN ISSUES*				

(4) Customer curtailment cost

ECONOMIC INDICATOR (EI) →		TOTAL CUSTOMER EXPORT CURTAILMENT COST (CECV) - $M AUD																			
↓ ALTERNATIVES ↑	#1 **Network reinforcement (NR)**	9	9	9	10	10	9	9	9	10	10	9	9	9	10	10	266	266	266	266	266
	#2 **NR + Controllability** *Heating and Cooling (H&C)*	9	9	9	10	10	9	9	9	10	10	9	9	9	10	10	266	266	266	266	266
	#3 **NR + Controllability** *Domestic hot water (DHW)*	9	9	9	9	9	9	9	9	9	10	9	9	9	10	10	261	262	262	262	262
	#4 **NR + Controllability** *Electric Vehicles (EV)*	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9	243	244	245	245	245
	#5 **NR + Controllability** *Distributed BESS*	5	6	6	6	6	5	5	5	6	6	7	7	7	7	7	249	249	250	251	251
SCENARIO NUMBER →		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
RISKS →		*BASE CONDITIONS*					*LOW DER 50% AVAILABLE CAPACITY*					*LOW DER 25% AVAILABLE CAPACITY*					*SUPPLY CHAIN ISSUES*				

Table A3.5 - Computed economic indicators to inform decision-making – CBTS case study application

ALTERNATIVES		DECISION CRITERIA SUMMARY			
		MINIMISE	MINIMISE	MINIMISE	MINIMISE
		(A) *Scenario-weighted mean* NPC *(A$M)*	**(B)** *Worst regret of* NPC *(A$M)*	**(C)** *Worst weighted regret of* NPC *(A$M)*	**(D)** *Scenario-weighted mean curtailment cost (A$M)*
#1	**Network reinforcement (NR)**	1320.23	198.15	26.95	46.10
#2	**NR + Controllability** *Heating and Cooling (H&C)*	1236.09	125.64	13.23	46.10
#3	**NR + Controllability** *Domestic hot water (DHW)*	1304.85	178.28	24.63	45.00
#4	**NR + Controllability** *Electric Vehicles (EV)*	1147.13	45.52	0.65	41.96
#5	**NR + Controllability** *Distributed BESS*	1204.50	72.45	10.35	40.60

1st best alternative for a given criterion

2nd best alternative for a given criterion

Table A3.6 - Summary of decision-making criteria for the case study – CBTS case study application

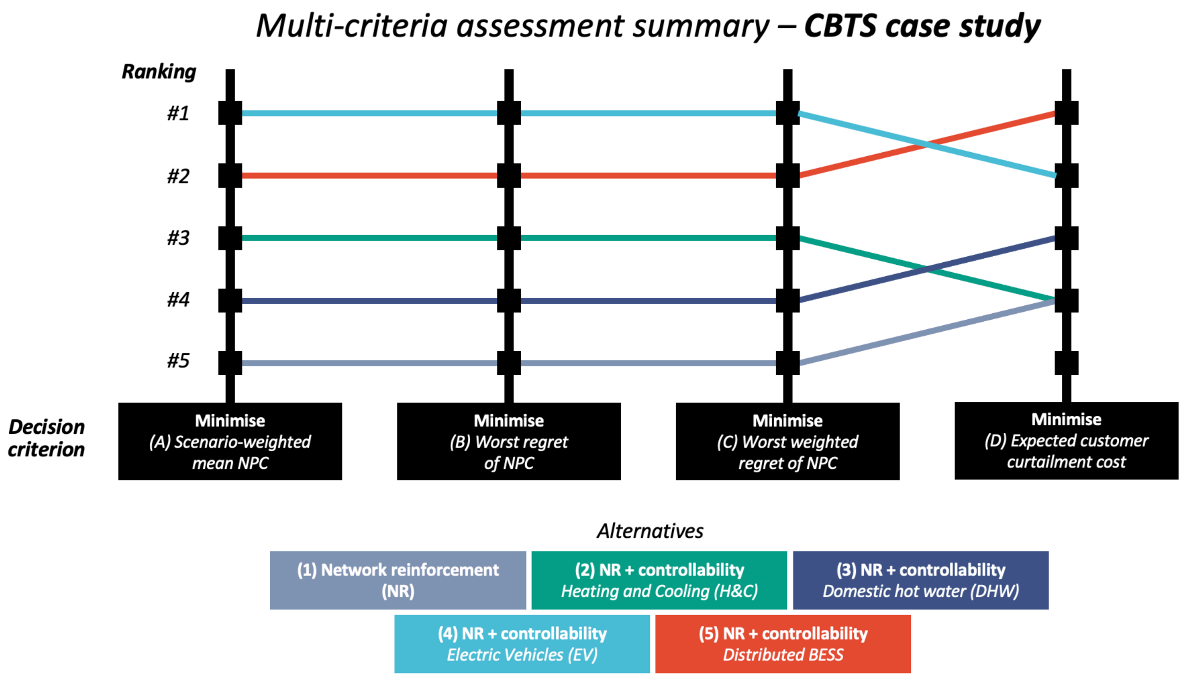

Figure A3.5 - Integrated visualisation of the multi-criteria assessment results - CBTS case study application

Appendix Four – ESP project and research partners