Work Package 2.9: Techno-Economic Modelling of Non-Network Solutions

Final Report

Report prepared for C4NET

Project Consortium

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Executive Summary

Distribution systems, particularly in Australia, are undergoing a profound transformation, characterised by the rapid uptake of 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, for example of over-investment and stranded assets, which could lead to increased costs for consumers. Figure 1 illustrates uncertainties surrounding modern distribution systems in the State of Victoria, Australia.

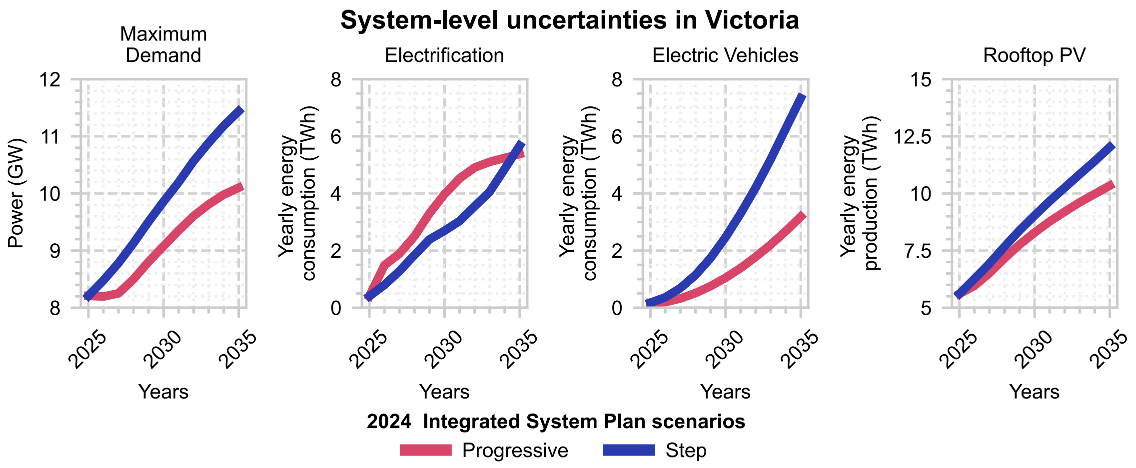

Figure 1: Distribution system-related uncertainties in the State of Victoria, Australia.
Figure elaborated with data sourced from [1]

Single-scenario network planning approaches[1] 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. Hence, this report aims to address three fundamental questions to improve the consideration of DER-based, non-network solutions:

- *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?*

Under this context, Work Package 2.9 of C4NET's *Enhanced System Planning (ESP) project* focuses on the techno-economic modelling and impact assessment of integrating DER into distribution system planning (DSP). The project provides a structured, transparent and quickly implementable decision-

[1] 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.

making framework to assess the risks, costs, and benefits when leveraging DER-based, non-network options as an alternative to network augmentation at any level in distribution systems (LV, MV, sub-transmission), especially in a context with significant electrification.

Addressing uncertainty and flexibility in network planning

Following a review of network planning-related concepts and current practices in Australia, an in-depth discussion offers a detailed perspective on better factoring operational and investment flexibility, as well as uncertainty and risk, into the distribution system planning process. The principal insights and recommendations for stakeholders from this systematic review include:

- Enhance current planning frameworks to explicitly account for scenario-based uncertainties (exogenous and endogenous) when valuing all investment options, in particular, demand-side resources. This will lead to more informed and robust long-term investment strategies.
- 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.
- Aim for planning techniques and philosophies that actively identify flexible *"compromise solutions"* across various scenarios. This will enable adaptive strategies, significantly reducing the risk of committing to inflexible assets in an uncertain context.
- Foster collaboration among stakeholders to establish and ensure the consistent application of standardised methods for valuing the benefits of flexibility (investment and operational) across all resource types (network and non-network technologies). This step is crucial for achieving uniform outcomes, ensuring fairer comparisons, and incentivising the development of adaptable and value-adding solutions.

Methodological considerations for valuing non-network solutions and addressing planning risks

Recognising the escalating relevance of DER-based, non-network technologies and the critical need for investment flexibility in the face of planning uncertainties, this WP proposes a comprehensive decision theory-based planning framework. Figure 2 provides a graphical summary of the proposed methodological framework.

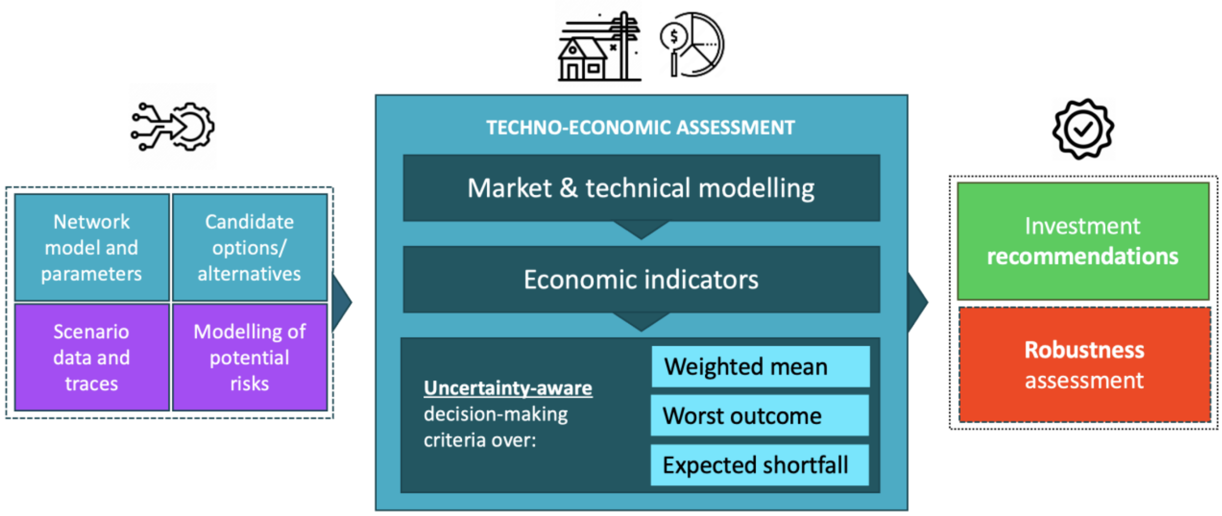

Figure 2: Graphical summary of the decision-making framework.

The framework, tailored to align with existing planning processes, aims to provide actionable recommendations for enhancing distribution system planning practices. It introduces a transparent methodology to quantify the techno-economic value of non-network solutions, supporting more informed, value-driven investment decisions. Ultimately, the goal is to strengthen planners' risk management capabilities by systematically addressing uncertainties and trade-offs across alternatives. Key insights and recommendations for stakeholders include the following:

- Progressing towards a multi-criteria assessment in the evaluation of alternatives will allow to explicitly quantify and envisage the potential planning risks associated with investment decisions. Understanding the potential downsides of each option will enable the development of more risk-aware planning strategies and enhance confidence in long-term investment plans. As illustrated in Figure 3, adopting such a framework would empower planners to make well-informed, transparent choices that proactively address planning risks and optimise outcomes across a range of future scenarios.

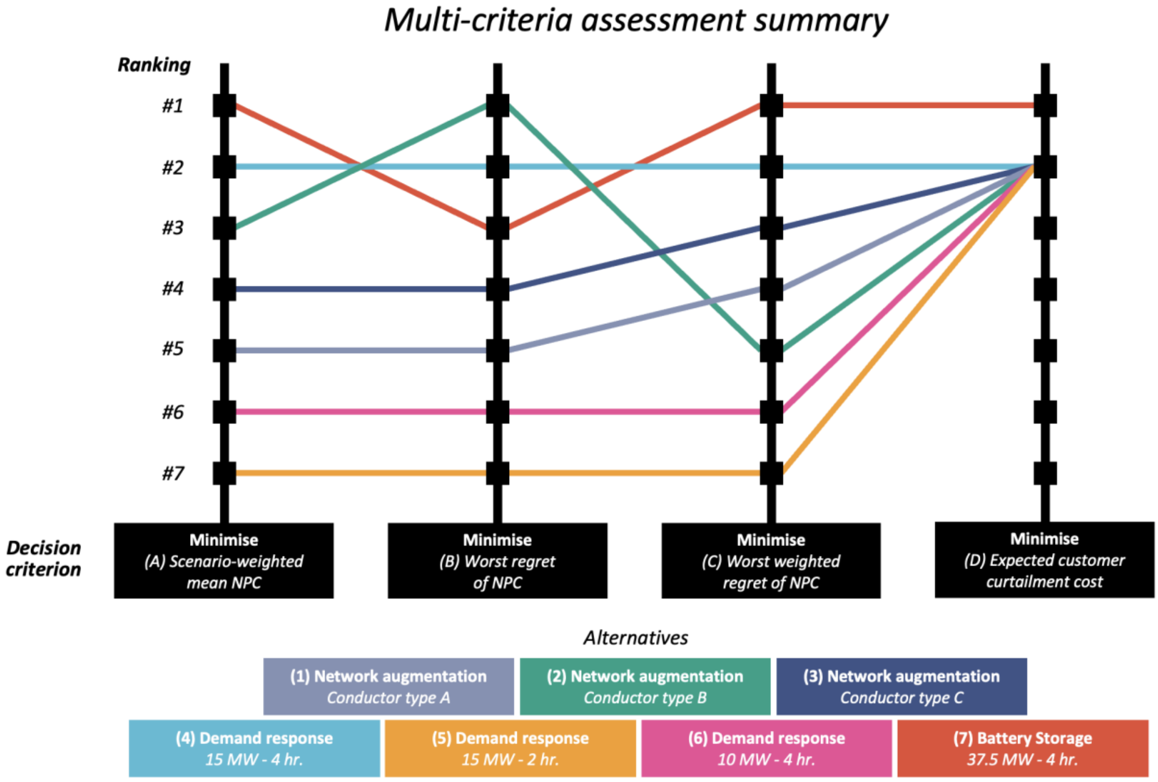

Figure 3: Integrated visualisation of the multi-criteria assessment results.

- A multi-criteria assessment reveals important trade-offs between cost, regrets, and various technical benefits (e.g., reduced curtailment), facilitating more informed and value-driven decisions that consider a broader range of factors beyond just initial capital expenditure.
- The incorporation of a systematic approach to explicitly model and analyse a range of plausible future scenarios (considering DER uptake, electrification, load growth, etc.) using informed scenario weighting would lead to more adaptable investment decisions that better account for the inherent uncertainties of modern energy systems.

Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANM	Active network management
APGC	Active power generation curtailment
CER	Consumer energy resources
CECV	Customer export curtailment value
DER	Distributed energy resources
DNSP	Distribution network service provider
DR	Demand response
EV	Electric vehicle
HV	High voltage
ICT	Information and communication technologies
ISP	Integrated System Plan
LV	Low voltage
MV	Medium voltage
NEM	National Electricity Market
NER	National Electricity Rules
NNA	Non-network alternatives
NNS	Non-network solutions

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1. Introduction

a. Background

Australia has experienced a significant increase in the adoption of DER over the past decade, especially in solar photovoltaic and distributed battery storage systems [2]. This trend has been accompanied by the ongoing electrification of various energy consumption sectors, including transport [3], heating and cooling [4], domestic hot water, among others. According to AEMO's projections, the deployment of DER as well as electrification trends are expected to continue growing in the coming decades, with forecasts indicating significant installed capacity by 2050 [5], as illustrated in Figure 4:

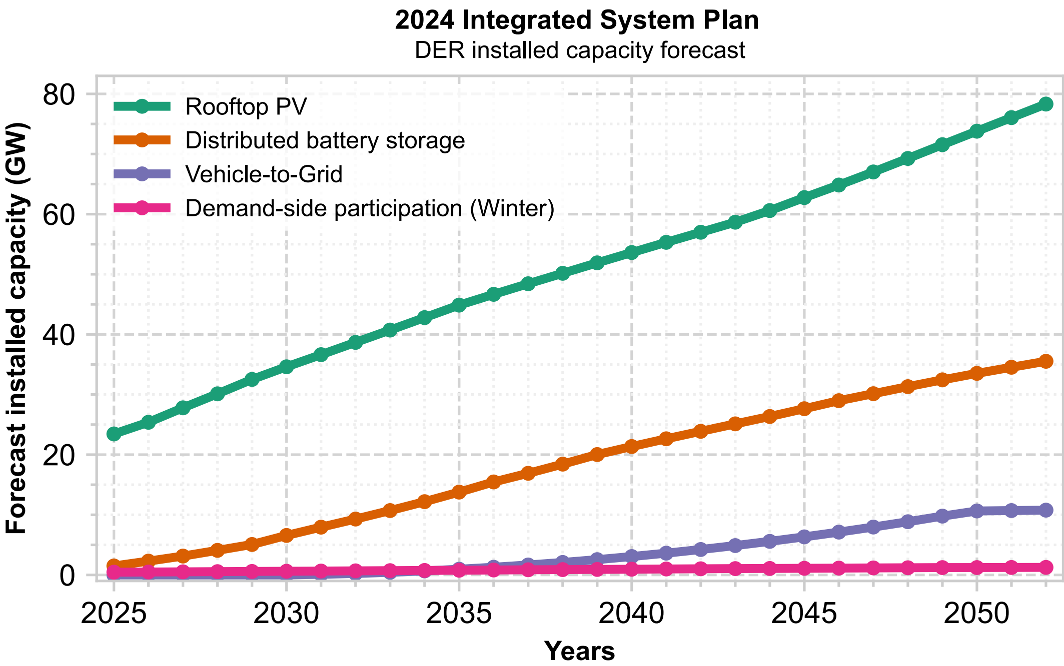

Figure 4: 2024 AEMO's Integrated System Plan forecast for installed capacity of DER, Step Change scenario. Figure elaborated with data sourced from [1].

The significant adoption of 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 this shift could provide considerable benefits to various stakeholders, it also presents significant challenges and opportunities in the operation and planning of distribution systems.

In the medium to long term, varying DER adoption levels and demand growth trends introduce significant uncertainty in network planning. In Australia, distribution network investments are ruled by an annual regulatory planning process with a minimum five-year forward planning horizon [6]. Thus, addressing these uncertainties with traditional deterministic, single-scenario approaches proves challenging, particularly in ensuring that the network capacity is adequate to handle a broad range of potential technical issues while avoiding capital misallocation. The conventional *"fit-and-forget"* approach [7], which relies on a single, worst-case scenario for forecasting peak demand growth, could lead to network over-investments given the uncertainty in load growth, trends in DER adoption and electrification, ultimately undermining capital efficiency.

While non-controllable DER could pose operational and planning challenges, it has been proven that establishing effective control strategies and information and communication technologies (ICT) to manage these assets actively [8] 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. This can be accomplished, for example, by reducing demand during peak times, shifting consumption to off-peak periods, storing surplus generation to avoid curtailment, or allowing managed curtailment to prevent network overload. Moreover, effectively utilising these demand-side controllability options could potentially decrease or delay the need for costly and extensive network upgrades or other enhancements (such as line upgrades or transformer replacements), which may become stranded if the anticipated scenario fails to materialise.

Therefore, for non-network solutions to emerge as viable planning alternatives to traditional reinforcements, planners must conduct thorough evaluations to determine their potential value compared to conventional network augmentations. Such an assessment must consider key aspects, including their potential costs and benefits, measured by several techno-economic indicators, an accurate representation of uncertainty in critical parameters like demand growth, the uptake of DER, and consumer engagement with DER coordination, as well as the inherent economic and physical risks linked to network and non-network options.

In this regard, to better integrate demand-side, non-network options into distribution system planning, this project focuses on developing, testing, and providing methodological recommendations for an enhanced decision-making framework in distribution systems. The main target is to guide and provide actionable insights to Australian DNSPs in enhancing their current planning processes for the valuation and assessment of these alternatives.

b. Project Objectives

Work Package (WP) 2.9, *"Techno-economic modelling, impact assessment, and planning methodologies to value non-network solutions, future network investment, and associated risks in the context of electrification"*, as part of the C4NET Enhanced System Planning (ESP) project, aims to:

- Outline the methodological recommendations for enhancing and advancing the current distribution system planning framework to adequately assess and value the optionality of CER/DER-based solutions.
- With relevant case studies, demonstrate the broad applicability of the proposed methodological framework in a context of high electrification and DER adoption.
- Assess and quantify the potential benefits of adopting CER/DER alternatives compared to traditional network reinforcements (e.g. line upgrades or transformer replacement) in hedging against planning uncertainties and subsequent risks.

Overall, WP 2.9 provides methodological recommendations and actionable insights towards enhancing current distribution system planning practices. Furthermore, it establishes a decision-making framework designed to explicitly incorporate long-term uncertainty and risk considerations, leading to more informed assessments of the potential value of non-network, CER/DER-based options in distribution system planning.

c. Milestones

The milestones established for WP 2.9 are described in Table 1:

Table 1: Work Package 2.9 milestones

Milestone number	Description	Expected completion
Milestone 1	Literature Review	November 2024
Milestone 2	Methodological approaches for an enhanced techno-economic planning framework	January 2025
Milestone 3	Benefit assessment from flexible solutions based on electrification in providing network investment risk mitigation across different network areas and for different scenarios	February 2025
Milestone 4	Final report with summary of input data and assumptions book	April 2025

d. Report structure

- **Section 2** presents a review of relevant literature, covering the concepts of investment and operational flexibility, the impact of uncertainty on network planning, and current planning practices in Australia.
- **Section 3** details the proposed decision-making framework, outlining the approach for planning and valuing the deployment of non-network solutions under conditions of uncertainty.
- **Section 4** describes the input data and key assumptions employed to demonstrate the application of the proposed framework in subsequent case studies.
- **Section 5** presents illustrative and detailed case studies to showcase the practical application and insights derived from the decision-making framework.
- **Section 6** summarises the key findings of the report and provides recommendations for stakeholders.

2. Literature review

This section presents a review of relevant literature for this report. It addresses the key topics explored in this document, including concepts such as operational and investment flexibility, the impacts of uncertainty, and associated risks in network planning. It also provides an overview of current practices for distribution system planning in Australia to outline potential improvement areas. This section complements the extensive literature review delivered with Milestone 1.

a. Concepts of flexibility for valuing technological options

I. Investment flexibility

The literature has explored the concept of **investment flexibility** in various instances [9], [10], offering a broad definition. In the context of system planning, *flexible investment options* can be understood as technological alternatives (a portfolio of single or multiple assets) whose technical, locational, operational, and/or procurement characteristics allow them to serve as *compromise solutions*. Such compromise solutions could eventually deliver value across a wide range of potential future scenarios, effectively hedging against planning uncertainty arising from changes in endogenous system characteristics (e.g., demand growth, renewable energy variability, DER uptake, etc.) or exogenous factors (e.g., technological development, market conditions) [11].

Seeking for investment flexibility

As previously discussed, investment flexibility involves identifying *alternatives* (also referred to as solutions) capable of generating or capturing value across multiple future scenarios, thereby providing improved hedging against uncertainties. If a deterministic perspective is adopted, it's straightforward to identify potential investments that balance their system constraint relief against their costs. When this analysis is then performed across multiple scenarios, decision-makers can select an *alternative* that delivers consistent performance across scenarios according to defined criteria.

II. Operational flexibility

In the context of power systems, **operational flexibility** can be broadly defined as the capacity of system components to modify their power exchanges with the grid within a specified time interval [12]. In distribution systems, operational flexibility can arise from the management of different resources. Examples include controllable and schedulable loads (e.g., heating, cooling, hot water systems, EV storage), distributed generation, energy storage systems, and manageable network assets.

To harness this flexibility potential, various management schemes can be employed, including but not limited to active power generation curtailment (APGC), demand response (DR), and active network management (ANM). The implementation of these schemes aims to increase the control over these assets, allowing adjustments to their consumption or generation patterns, particularly during periods of high grid strain. This enhanced controllability ultimately contributes to alleviating network stress, mitigating congestion and/or reducing reliance on imports, leading to lower operational costs and potentially avoiding or delaying the need for significant and costly network upgrades.

III. Relationship between investment and operational flexibility

Having reviewed the concepts of investment and operational flexibility, it is crucial to understand their interaction in the context of distribution system planning.

Investment flexibility aims for technological options (comprising one or more assets of the same or different kinds) capable of delivering value across various future scenarios. In this regard, equipment that offers greater operational flexibility by actively managing power exchanges with the grid (both consumption and production) based on specific technical requirements is likely to offer more investment flexibility. This synergy can be attributed to two main reasons:

1. The ability to operate flexibly in response to external signals (coming from the market or centralised control) could improve adaptability to various future scenarios (for example, of load growth), thereby providing a better means of handling uncertainty.
2. Assets in distribution systems that can be managed for a flexible operation, such as battery storage systems, distributed generation, or controllable loads, usually require shorter rollout periods [7]. Under an established coordination ecosystem (e.g., with ICT infrastructure and regulation put in place), it would be possible to achieve a quicker deployment of solutions based on these technologies, minimising lead times. On the other hand, uncertain and potentially extended lead times hampering network upgrades may diminish their anticipated benefits.

Therefore, in a future characterised by significant DER uptake, the presence of controllable assets within distribution systems will eventually foster greater operational flexibility. Furthermore, this enables the development of a broader spectrum of investment alternatives, encompassing non-network solutions and hybrid network-DER deployments. Such an expanded solution space would offer decision-makers increased investment flexibility while mitigating exposure to higher capital expenditures and the risk of pursuing economically inefficient investment strategies [13].

b. Considerations of uncertainty and risk in network planning

In network planning, DNSPs face two primary risks arising from uncertainty. First, there is the **economic risk** associated with investment inefficiency, which could result in regulatory clawback or impose unnecessary costs on consumers when assets or network upgrades are underutilised. Second, there is the **physical risk** of insufficient investment in network capacity, which could cause reliability issues, for example, if demand growth outpaces projections or non-network assets underperform.

The increasing adoption of DER and electrification trends exacerbate planning uncertainty, particularly regarding the question of whether to augment the network. In this context, implementing enhanced DER control strategies offers a viable pathway to mitigate the associated economic risks.

Academic literature [8], [13], [14], [15] suggests that demand-side options responsive to external signals (e.g. coming from centralised coordination) could be more cost-effective than traditional network reinforcements. Such options would allow for greater adaptability to varying peak demand scenarios rather than being designed mainly for worst-case conditions, such as the latter. Therefore, by relying on non-network, DER-based solutions, DNSPs in Australia could opt for a *"wait-and-see"*[2] approach, delaying significant network investments until uncertainties are better resolved. This inherent investment flexibility offered by non-network options becomes particularly valuable when uncertainties are effectively factored into the planning process.

On the other hand, prioritising DER-based solutions over network assets may involve a trade-off concerning physical risk. The availability and capacity of DER to provide flexibility-based services to the system can fluctuate due to weather conditions, market trends and consumer preferences, potentially diminishing their reliability compared to network assets. Therefore, during the planning process, when valuing and assessing potential capabilities offered by non-network solutions, it is essential to thoroughly consider the possibility of reduced availability for services related to power injections or consumption management.

In summary, it is crucial to highlight that when considering DER-based, non-network options, a trade-off exists between cost savings and reliability compared to investing in network reinforcements. While opting for flexibility options may reduce costs and mitigate economic risks, it might increase the physical risk in the operation of distribution systems. Therefore, a robust methodological framework is essential to accurately assess and value DER capabilities as alternatives to network upgrades. This framework must comprehensively address both economic and physical risks, providing decision-makers with a sound basis for informed investment strategies.

c. Current practices and regulation for distribution system planning in Australia

This section outlines the regulatory and methodological framework that governs distribution system planning (DSP) in Australia. The objective is to provide a general understanding of the established processes and to highlight opportunities for methodological improvements, particularly in the valuation and integration of non-network solutions.

Distribution annual planning review

The National Electricity Rules (NER) regulate distribution system planning in Australia, requiring each Distribution Network Service Provider (DNSP) to conduct an annual planning process. Key aspects of this process include:

[2] Some decisions are made *here-and-now* assuming uncertainty regarding the unfolding of the future (e.g. start the procurement of permits to deploy a distribution line) and other decisions are made in the future when more information is available; these decisions are known as *wait-and-see* decisions (e.g. start construction, decisions on transfers through a high voltage direct current (HVDC) link, etc.) [11]

- The distribution annual planning review must cover a minimum forward planning period of 5 years.
- Each DNSP, with respect to its network, must fulfil the following requirements:

  1) Forecast maximum demand and demand for distribution services from embedded generation for sub-transmission lines, zone substations, and primary distribution feeders to the extent practicable.
  2) Identify network constraints based on the peak demand forecasts of 1). These constraints include network capacity limitations, asset refurbishment or replacement needs, system security and reliability requirements, fault level exceedances, voltage regulation, and compliance with regulatory obligations.
  3) Determine corrective actions for constraints identified in 2), assessing whether identified constraints require a Regulatory Investment Test for Distribution (RIT-D) and associated demand-side engagement.
  4) Develop a strategy to engage with non-network providers and consider non-network options for addressing system constraints, aligning with its demand-side engagement strategy.
  5) Publish a Distribution Annual Planning Report (DAPR) by the DAPR date or, if no such date is specified, by December 31 each year.

Demand-side engagement

The NER mandates that DNSPs engage with non-network providers and assess NNS to address system constraints in accordance with their demand-side engagement strategy. Based on the information published in various DAPRs [16], [17], [18], [19], each DNSP has its approach to engaging with non-network solution providers and implementing such alternatives. In this context, to understand the current state regarding demand-side engagement, a review of the DAPRs for DNSPs in Victoria has been conducted, resulting in diverse outcomes:

- Mobile generation and established demand management portfolios are being explored in feasibility assessments for NNS, particularly in network augmentation projects with capital costs below $6 million[3] [16].
- Ongoing engagement with non-network providers continues to be a strategic focus, although no submissions were received for the planning year 2024 [17].
- While no demand management initiatives were identified as capable of deferring network investments in 2024, recent reforms in wholesale demand response (DR) are expected to enhance the potential for market-driven DR services [18].

In this regard, it is noted that there is not a unified, systematic framework for developing, incorporating, and comparing non-network alternatives to compete with, displace, or delay network

[3] For cases where network augmentations have a capital cost higher than 5 million, the regulatory investment test for distribution (RIT-D) mandates the consideration of non-network options.

augmentations across DNSPs, particularly for projects falling outside the scope of the RIT-D. Instead, the potential adoption of non-network alternatives is typically assessed case-by-case for specific applications.

Network planning standard and Probabilistic planning approach

The network planning process undertaken by Australian DNSPs for distribution systems involves a systematic series of steps to identify constraints, performance issues, and other relevant challenges, which are then addressed through various measures. To comply with the requirements of the NER, DNSP planning activities are generally summarised as follows:

1. Forecast minimum and maximum load as well as capacitive currents.
2. Review the existing capability of the network infrastructure.
3. Identify of network constraints or performance issues based on the forecasts and network capabilities.
4. Formulate potential network augmentation options to resolve identified constraints and actively seek non-network options, including demand-side solutions.
5. Analyse all identified options to ensure compliance with technical limits, planning standards, regulatory requirements, system stability, and other relevant criteria.
6. Develop detailed cost estimates for each viable option and determine the most cost-effective alternative. If network augmentation capital costs exceed $5 million, the Regulatory Investment Test for Distribution (RIT-D) must be undertaken.
7. Investigate the economic viability of the most cost-effective alternative.

The probabilistic planning approach, used to assess the most cost-effective option, compares the economic cost of probability-weighted energy-at-risk (due to contingency events, reliability gaps, or performance shortfalls) with the cost of mitigating this risk or improving network performance. This approach provides an estimate of the expected net present value to consumers resulting from distribution system augmentation, retirement, or replacement projects. A key implicit aspect of this approach is the acceptance of a certain level of risk that the available distribution network may, under specific circumstances, be insufficient to fully meet the actual demand for distribution services [16].

Regulatory investment test for distribution (RIT-D)

The Regulatory Investment Test for Distribution (RIT-D) [20], overseen by the Australian Energy Regulator (AER), is a cost-benefit analysis framework that aims to identify the most economically beneficial option, whether network or non-network, while ensuring long-term value for customers. The RIT-D applies to cases with network investments exceeding $5 million.

The objective of the RIT-D is to identify the preferred option that maximises the net economic benefit for all electricity producers, consumers, and transporters in the National Electricity Market (NEM). In a particular case, if the investment need relates to reliability corrective actions, the preferred option may still have a negative net economic benefit (that is, a net economic cost) [21].

When assessing potential options, as stated in clauses 5.17.4 (b) - (e) [21]. of the National Electricity Rules, an RIT-D proponent must publish an *options screening report* detailing:

(a) The identified need and assumptions employed in identifying the identified need.

(b) The **annual augmentation deferral value** charge associated with the identified need.

(c) Technical requirements of the identified need for potential NNS, including:

- Load reduction size or additional supply capacity.
- Location requirements.
- Contributions to system security, reliability, and fault levels.
- Expected operational profiles.

(d) A summary of potential credible options, including network and non-network options to address the identified need, outlining:

a. Technical characteristics and requirements from (c).
b. Estimated construction and commissioning timelines.
c. Indicative capital and operating costs.

An RIT-D proponent is not required to publish an options screening report if it reasonably determines that no non-network option qualifies as a credible alternative or forms a significant part of one for addressing the identified need. If the proponent decides not to proceed with the options screening report, it must, as soon as possible, publish a notice outlining the rationale behind its decision, including the methodologies and assumptions used in reaching that conclusion.

Overall, the review of the RIT-D process indicates that while it mandates the consideration of non-network options, key challenges remain in their selection and assessment. In particular, the *options screening report* may overlook opportunities to incorporate uncertainty considerations, which is crucial for valuing different alternatives.

One critical aspect to consider is the ***augmentation deferral value***, referenced in clause 5.17.4 (b) of the NER. This value represents the economic cost (or benefits) of reinforcing the network using traditional assets (e.g., reconductoring or transformer upgrades). While this value is a key input in a potential assessment regarding non-network alternatives, it is highly sensitive to uncertainty in several factors that could lead to non-negligible misestimations. Such uncertainties could include capital costs, project lead times, financing conditions (e.g., interest rates), and the potential benefits provided to the network. Consequently, a rigid valuation that does not explicitly incorporate these uncertainties risks overlooking valuable optionality in alternative solutions.

Furthermore, as clause 5.17.4 (d) indicates, the RIT-D requires an ***indicative cost estimate*** for each credible option, including ***capital*** and ***operational expenditures***. In particular, coordination costs (necessary to enable centralised control) could vary significantly depending on technology requirements and communication infrastructure for DER-based non-network solutions. Additionally, the operational costs for non-network options depend not only on their technical specifications but also on the expected service profile, including dispatchable power capacity and response characteristics. Given uncertainties in demand growth and DER uptake, the benefits of these solutions may fluctuate over scenarios, leading to a variable quantification of their value (and hence, costs).

Given these challenges, incorporating uncertainty considerations into the valuation of alternatives could lead to better-informed investment decisions, reduce the risk of over- or under-investment, and enhance the consideration of non-network alternatives and the overall efficiency of the planning process.

d. Lessons learnt and directions

The previous sections provided an overview of critical investment concepts and current methodologies for distribution system planning in Australia. The review highlighted key areas where methodological improvements could be beneficial in informing stakeholders about their planning process and providing an enhancement for the integration, promotion, and valuation of non-network solutions. The following takeaways summarise important considerations and directions of this work package:

- **Investment and operational flexibility as key enablers of a cost-effective system planning**: The interplay between investment and operational flexibility is crucial in a landscape with increasing DER penetration and demand variability. Resources that can potentially operate flexibly and at the same time have reduced deployment times, such as distributed batteries, EV charging stations or heating and cooling appliances, could allow better handling of the planning risks (over-investments and stranded assets) associated with uncertain load growth. A systematic approach to adequately valuing such operational and investment flexibility across network and non-network solutions could lead to more efficient investment plans.
- **Need for a robust and transparent framework to account for uncertainty and risks**: Current planning frameworks often lack a structured approach to incorporating uncertainty in the valuation (i.e., the estimation of costs or value) of investment options, particularly for demand-side, non-network solutions. Economic factors such as capital costs, project lead times, and financing conditions, as well as systemic parameters such as load growth, DER adoption and customer participation rates, introduce significant uncertainties and risks in network planning. Without explicit uncertainty modelling, planners might overestimate the feasibility or costs of network augmentations or underestimate the value of non-network alternatives that could offer greater adaptability to future scenarios.
- **Enhancing decision-making and economic considerations of non-network options with comprehensive uncertainty-aware scenario analysis:** Given the growing yet uncertain trends in electrification and DER uptake at the distribution system level, planning decisions should be guided by a structured decision-making framework that incorporates scenario analysis and explicitly considers uncertainties leading to economic and physical risks. A

methodological framework that can account for such uncertainties, such as demand growth, DER participation, and capital costs, would support investments by enabling more informed decisions regarding the economics, timing, and capacity of selected alternatives, thereby preventing premature or unnecessary network expansions. Furthermore, in the absence of unified guidelines for economically assessing options, for example, to identify the least-cost alternative across scenarios, a more standardised valuation approach would enhance consistency across planning practices and facilitate greater knowledge sharing within the industry.

3. A decision-making framework for valuing non-network solutions in distribution system planning

The increasing uptake of DER and electrification trends have introduced a significant layer of uncertainty into distribution system planning. This uncertainty engenders both economic and physical risks that conventional planning approaches often struggle to address adequately. The reliance on deterministic planning approaches renders them particularly vulnerable to these inefficiencies, as infrastructure investments based on single-scenario assessments may not align with diverse potential future states of the system. Under this context, this section outlines the methodological requirements and steps **towards developing a decision-making framework that facilitates uncertainty and risk considerations and better informs about the potential value of CER/DER-based options in distribution system planning**.

This framework, grounded in established decision theory principles [22], [23], facilitates a systematic evaluation of multiple investment alternatives through the consideration of economic indicators, decision-making functionals, and decision criteria. By accommodating multiple future scenarios and their associated risks, this framework enables the identification of optimal alternatives from a comprehensive set of candidate solutions, encompassing both network and non-network options. Furthermore, it provides a structured methodology for quantifying potential remuneration for non-network solutions, thereby enabling the incorporation of the value derived from augmentation deferral alongside other potential streams. In summary, this approach offers a transparent, multi-criteria assessment of the optionality and economic viability of non-network solutions, fostering informed decision-making in distribution system planning.

a. Framework overview

Figure 5 presents the overarching structure of the developed 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 generally, 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.

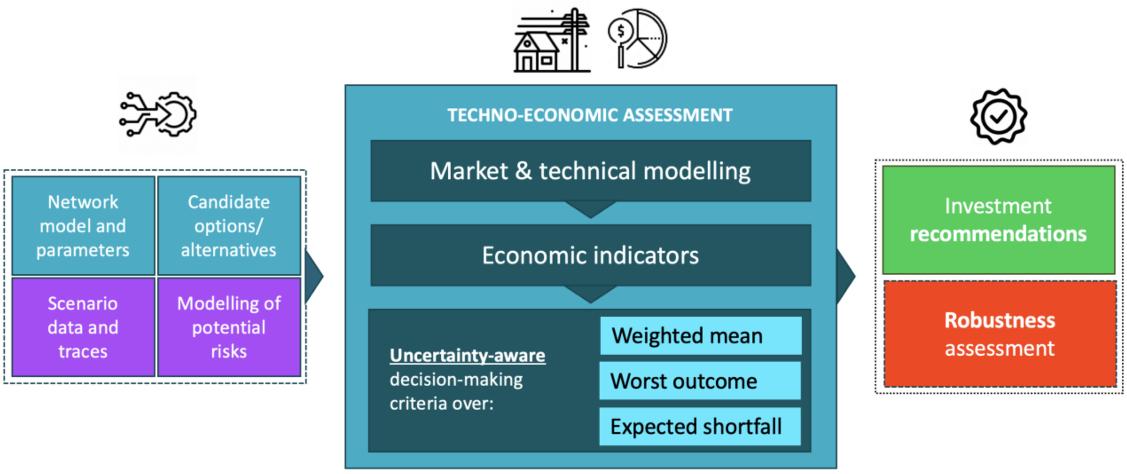

Figure 5: General structure of the proposed decision-making framework

b. Modules description

Figure 6 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 comprehensive description of each module.

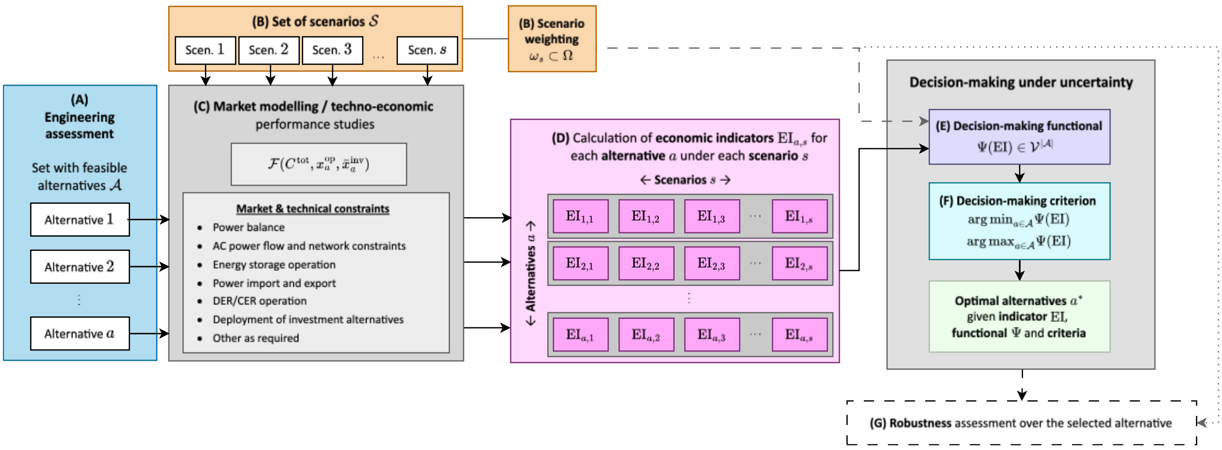

Figure 6: Technical overview of the decision-making framework.

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

In the context of distribution system planning in Australia, an **identified system need**[4] represents a specific objective that a distribution company aims to achieve through investment [21]. 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 2. 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.

Table 2: Illustrative example set of feasible alternatives to address a specific system need.

Example set of alternatives $\mathcal{A}$			
#	**Alternative**	**Technical characteristics**[5]	**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)[6]
5	Demand-side participation Alternative 2	Voluntary load reduction of 10 MW for 16 hours a year	\$ 2,000 – 12,000/MW (coordination cost)

[4] The NER define an *identified need* as the objective a Network Service Provider or a group of Network Service Providers seeks to achieve by investing in the network in accordance with the Rules or an Integrated System Plan.
[5] These characteristics are purely illustrative and only aim to give a general description of the technical aspects that should be detailed.
[6] Project EDGE Independent Full CBA Report https://arena.gov.au/knowledge-bank/aemo-project-edge-independent-cba-full-report/.

6	Battery energy storage	20 MW, 4-hour energy storage system	$ 2,000 – 12,000/MW (coordination cost)

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.
- 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 3 illustrates the construction of such a scenario set.

Table 3: Illustrative example set of scenarios to assess the candidate alternatives

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

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) [1], 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 emphasise 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 4 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%.

Table 4: Illustrative example for the weighting of scenarios across different cases.

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%**

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.

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

Table 5: Possible economic indicators to inform the decision-maker

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)*[7] 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.
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.

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).

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

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

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 6 summarises example functionals suitable for application within the decision-making process, highlighting their respective characteristics and potential implications.

Table 6: Possible functionals to incorporate in the decision-making process.

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.	$\mathbb{E}[\mathrm{EI}_{a,s} \mid \mathrm{EI}_{a,s} \geq \mathrm{VaR}_{\%}]$

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 7 details the application context for each criterion.

Table 7: Context and application of decision-making 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.

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 8 outlines examples of coherent pairings.

Table 8: Examples of reasonable pairings between economic indicator, decision-making functional and decision-making criterion.

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.

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.

c. Additional considerations

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).

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.

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 8, 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 7 provides an illustrative example of the interactions between these modules and their role in informing the decision-maker.

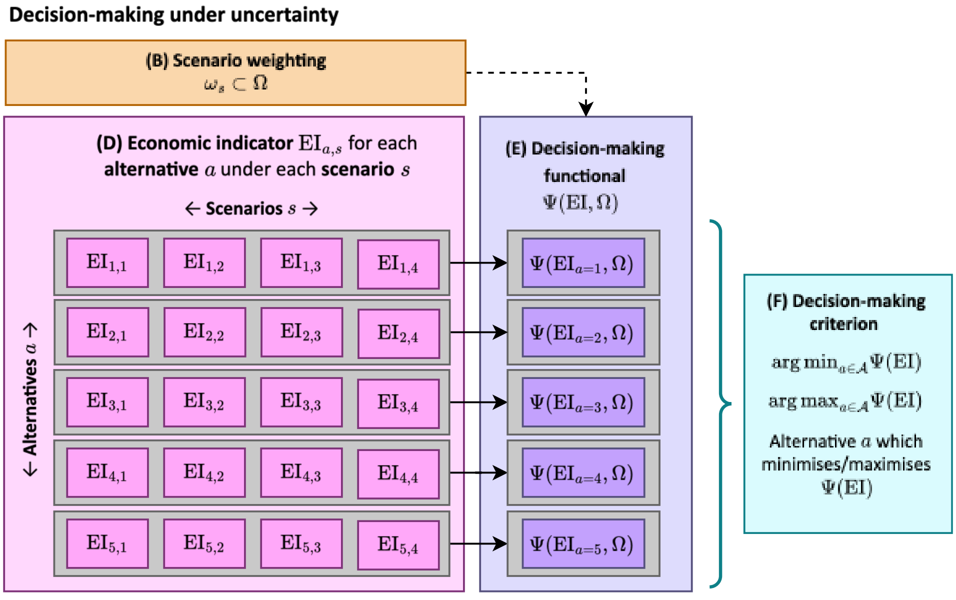

Figure 7: Example of the process for decision-making under uncertainty considering five possible alternatives and four scenarios.

- 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 7).
- 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.

4. Input data

This section details the input data and assumptions for the illustrative case studies performed in this project. The input data encompasses network models and associated cost information, pertaining to both network augmentation and non-network solutions. This data serves as the basis for the case studies, which demonstrate the applicability and insights derivable from the methodological framework proposed within this work package.

It is crucial to reiterate that this WP aims to develop a decision-making framework that facilitates the explicit consideration of uncertainty and risk in distribution system planning while contributing to improve understanding of the potential value inherent in CER/DER-based options. Therefore, the input data and values presented here are illustrative, mainly intended to demonstrate the framework's applicability. In this regard, no specific conclusions about the chosen AusNet network should be drawn from this assessment (input data and values are illustrative only).

a. Distribution network models

Canonical illustrative network

An illustrative radial distribution network is considered to demonstrate the applicability of the proposed decision-making methodology in a comprehensible manner. Figure 7 provides a schematic representation of this network. The network is designed to represent a sub-transmission loop, reflecting realistic demand patterns and rooftop PV penetration levels. The network comprises ten buses, with a peak load of 471.33 MW and an installed PV capacity of 164.14 MW in the initial planning year, as detailed in Table 9.

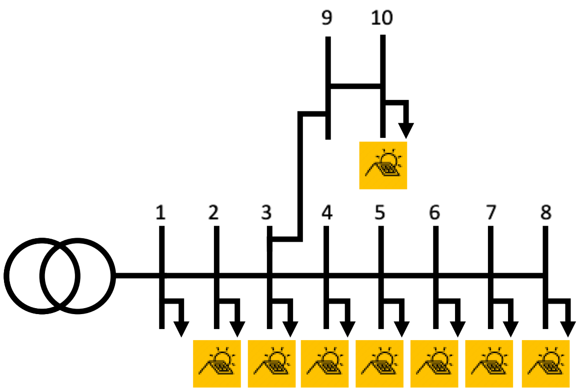

Figure 8: Illustrative 10-bus canonical distribution network model.

Table 9: Peak load and installed capacity of rooftop PV generation in the 10-bus canonical network in the initial planning year.

Busbar number	Peak load (MW)	Rooftop PV capacity (MW)
1	164	0
2	49.83	26
3	22.17	8.65
4	29.72	18.79
5	21.36	8.32
6	48.51	25.29
7	71.63	44.33
8	47.85	22.23
9	0	0
10	16.26	10.53
TOTAL	**471.33**	**164.14**

AusNet sub-transmission network models

Part of the data used for this WP corresponds to the network models developed in **WP 1.4: *Whole of Distribution Network Architecture*.** A total of five sub-transmission network models, owned by AusNet, were made available as a result of WP 1.4: Cranbourne Terminal Station (CBTS), Glenrowan Terminal Station and Mount Beauty Terminal Station (GNTS-MBTS), South Morang Terminal Station (SMTS), East Rowville Terminal Station (ERTS), Thomastown Terminal Station (TTS), and Templestowe Terminal Station (TSTS). For this work package, the **CBTS** network model was selected to perform relevant case studies.

It is worth mentioning that although the networks used for the case studies are sub-transmission loops, the decision-making framework can be applied to any distribution level and reference point (e.g., HV, MV or LV transformer). Investment assessments can be made at multiple reference points within distribution networks. In this sense, this methodology could aid in determining the benefits that might emerge from non-network solutions, for instance, at the MV-LV level, a topic that has not been explored thoroughly in real-world applications.

CBTS – Cranbourne Terminal Station

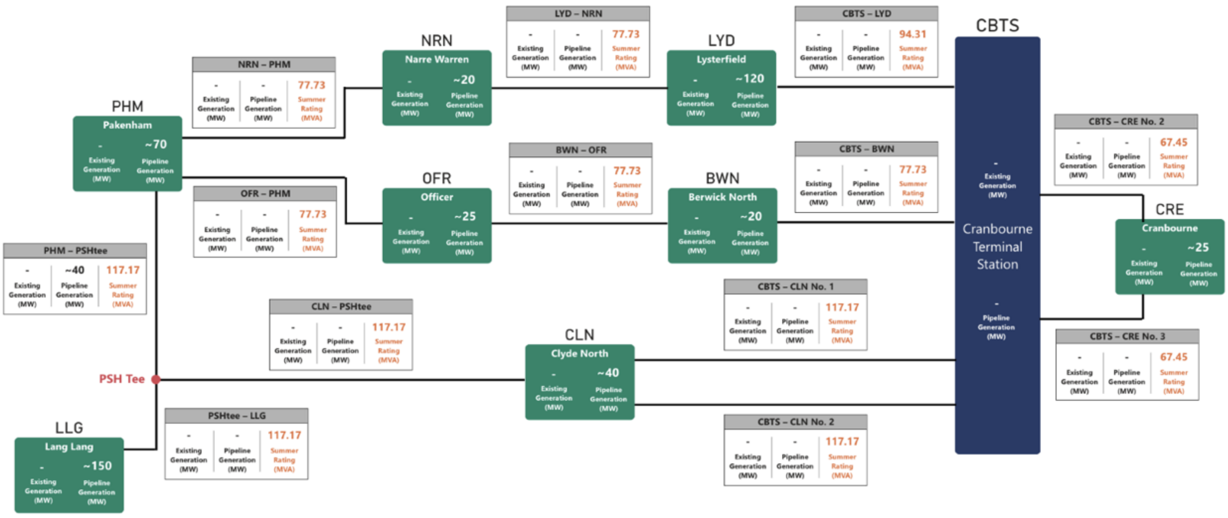

Figure 9: Cranbourne Terminal Station (CBTS) network model

The CBTS sub-transmission network is characterised with a rooftop PV installed capacity and a peak demand according to Table 10. 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 11.

Table 10: Rooftop PV capacity and peak demand for CBTS sub-transmission network, base year 2024.

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

Table 11: Zone substation composition for CBTS sub-transmission network

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

b. Cost data and assumptions

Capital cost for network augmentation

Reference capital cost for network augmentation, shown in Table 12, are based on publicly available information of recent regulatory investment tests for distribution (RIT-D) conducted by DNSPs for different sub-transmission assessments. These values specifically correspond to reinforcements assessed in the areas of Morwell South and East, Australia for connection enablement processes [24], [25].

Although these networks are not analysed, these costs serve as a good proxy for network reinforcements seen by AusNet considering 11,750 $/MVA/km as reference, which is the average cost of all these solutions but the cheapest ones. Reactive compensation is also considered as investment option in the form of SVC (injection and consumption of reactive power), using a cost of 200,000 $/MVAr based on the transmission cost database from AEMO [8]

Table 12: Reference costs for network augmentation.

Source	Alternative	$/MVA/km
Connection Enablement: *Morwell South Area (AusNet)*	**All aluminium 19/3.25 -** Option 1	$ 12,660
	All aluminium 19/4.75 - Option 2	$ 11,437
	All aluminium 37/3.75 - Option 3	$ 11,454
Connection Enablement: *Morwell East Area (AusNet)*	**All aluminium 19/4.75 -** Option 1	$ 2,232
	All aluminium 19/4.75 - Option 2	$ 3,017
	All aluminium 37/3.75 - Option 3	$ 11,696

[8] AEMO, Transmission Cost Database. https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database

Costs associated with the orchestration of non-network options

An important component of the investment planning analysis when considering potential DER-based non-network solutions is the cost associated with the orchestration of such resources. Under the assumption that non-network solutions need to be orchestrated or coordinated centrally to provide services, there is need for digital infrastructure to enable those communications. In the Independent cost-benefit analysis for Project EDGE [26], [27], three DER data exchange approaches were compared: point-to-point, centralised data hub and decentralised data hub. The analysis allowed establishing a proxy for the cost associated with digital and communication infrastructure to enable the coordination of DER. Table 13 summarises the approximate cost of coordination per unit of power for these three coordination approaches

Table 13: Reference costs for coordination of DER.

Coordination scheme	Estimated controllability cost $/MW
Point-to-point	$ 9,058
Centralised	$ 1,920
Decentralised	$ 1,709

5. Case study applications

This section presents the case studies undertaken as part of this project, demonstrating the practical applicability of the proposed decision-making framework. These case studies illustrate how a multi-criteria assessment can be systematically applied to evaluate investment alternatives, including network augmentation and non-network solutions, while explicitly accounting for planning uncertainty and risks in order to support more informed and robust decision-making.

The first case study is conducted on a canonical distribution network and showcases the framework's flexibility in applying various combinations of criteria to assess costs, risks, and benefits. This is followed by a case study on a Victorian sub-transmission network, demonstrating the applicability of the framework to identify the potentially most beneficial flexibility and controllability alternatives.

a. **Case study #1:** Applications of multi-criteria assessment to value non-network options

Setup of the case study

This case study uses the canonical network described in Figure 8 and Table 9. A five-year planning horizon, beginning in 2025, is selected to align with the minimum planning horizon required by the NER.

Identification of a system need

The first step is to identify potential issues or needs within the system. In this case, the five-year demand growth forecast suggests a risk of unmet demand during the winter peak at bus 7, specifically between 18:00 and 21:00. The potential demand not supplied arises because the distribution lines between buses 3 and 6 during these hours reach their maximum loading capacity (100%), limiting the system's ability to adequately supply demand. Figure 10 shows the loading levels of lines 3–4 and 5–6 during the critical period. Likewise, Figure 11 presents the load profile at bus 7, highlighting the demand at risk.

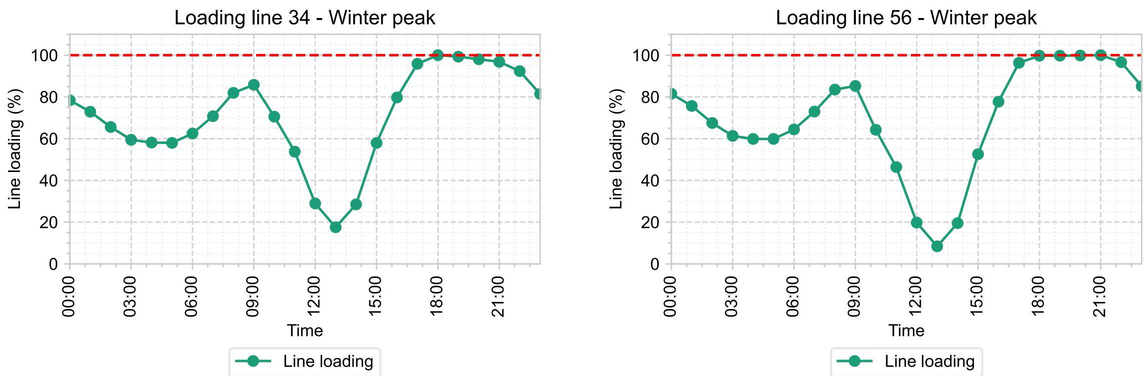

Figure 10: Load on lines 3-4 and 5-6 during the hours when the demand in bus 7 is at risk.

It is important to note that the network overload is expected to occur for no more than four hours per day. As shown in Figure 10, during the remaining hours, line loading remains below 85%, and in some cases, even drops below 20%. This suggests that a traditional network reinforcement may be economically inefficient, given the limited duration of the overload relative to the number of hours with sufficient capacity.

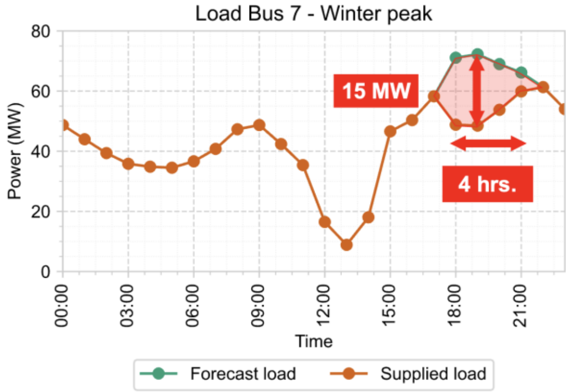

Figure 11: Forecast and expected supplied load profiles at bus 7, highlighting up to 15 MW of load at risk for a maximum of 4 hours.

Elaborating a set of feasible alternatives – Application of **Module (A)**

Once the system need has been identified, the planner must carry out a comprehensive alternative screening to design a set of credible solutions. This process typically involves engineering assessments, including power flow and stability analyses, to ensure the technical feasibility of each option.

In the illustrative case described, seven alternatives have been identified as credible options to address the issue. These alternatives include network augmentation, as well as non-network options. Non-network options comprise demand response with specific capacity and duration to address the demand at-risk, and a battery storage system capable of injecting power locally. Table 14 outlines the technical specifications and associated costs of each alternative.

Table 14: Technical and cost characteristics of the options to address the identified system need.

Set of alternatives to address the identified system need			
#	**Alternative**	**Technical characteristics**[9]	**Estimated capital / coordination cost**
1	*Network augmentation* Conductor type A	All aluminum conductor (AAC) – 19/3.25	$ 12,660/km/MVA
2	*Network augmentation* Conductor type B	All aluminum conductor (AAC) – 19/4.75	$ 11,437/km/MVA
3	*Network augmentation* Conductor type C	All aluminum conductor (AAC) – 37/3.75	$ 11,454/km/MVA

4	*Demand-side participation* at bus 7- Alternative A	Controlled load reduction of 15 MW for 4 hours	$ 2,000 – 12,000/MW (coordination costs)[10]
5	*Demand-side participation* at bus 7- Alternative B	Controlled load reduction of 15 MW for 2 hours	$ 2,000 – 12,000/MW (coordination costs)
6	*Demand-side participation* at bus 7- Alternative C	Controlled load reduction of 10 MW for 4 hours	$ 2,000 – 12,000/MW (coordination costs)
7	Battery energy storage system in bus 7	37.5 MW, 4-hour energy storage system	$ 2,000 – 12,000/MW (coordination costs)

For capital and coordination costs, the infrastructure costs for network augmentation (alternatives #1 to #3) are based on the details provided in Table 12. For non-network solutions (alternatives #4 to #7), the coordination costs considered are outlined in Table 13.

*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 12. 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.

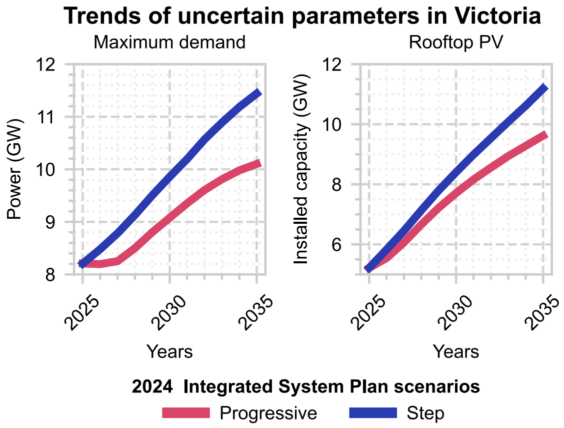

Figure 12: Trends for the scenarios considered in the illustrative case study application. Elaborated with data sourced from [1].

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

[10] Project EDGE Independent Full CBA Report https://arena.gov.au/knowledge-bank/aemo-project-edge-independent-cba-full-report/.

incremental “transition” scenarios, offering a higher fidelity representation of the unfolding of uncertainties over time [28]. Figure 13 provides a visual explanation of the logic underpinning this incremental scenario-transition approach.

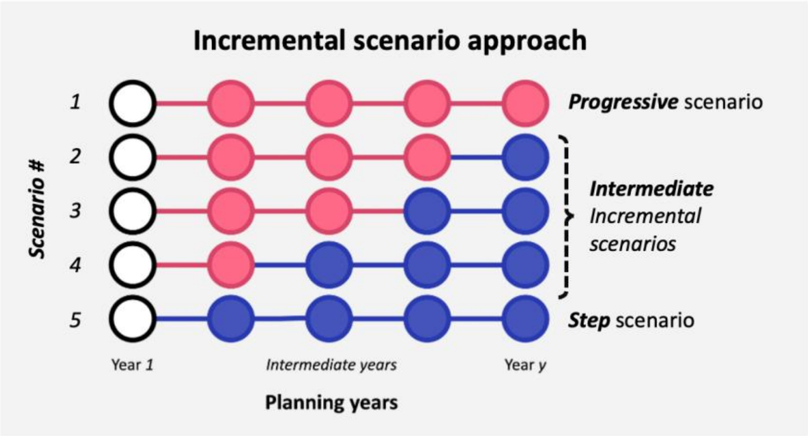

Figure 13: Design of scenarios to incorporate intermediate years with potential transitions in between.

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 15 summarises all the scenarios and weights ω_s considered for this particular case study.

Table 15: Scenarios designed for the illustrative case study application.

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%

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 14) was evaluated across every scenario using optimal power flow (OPF) analysis. Figure 14 shows the constraints included in this model and the relevant outputs it produced.

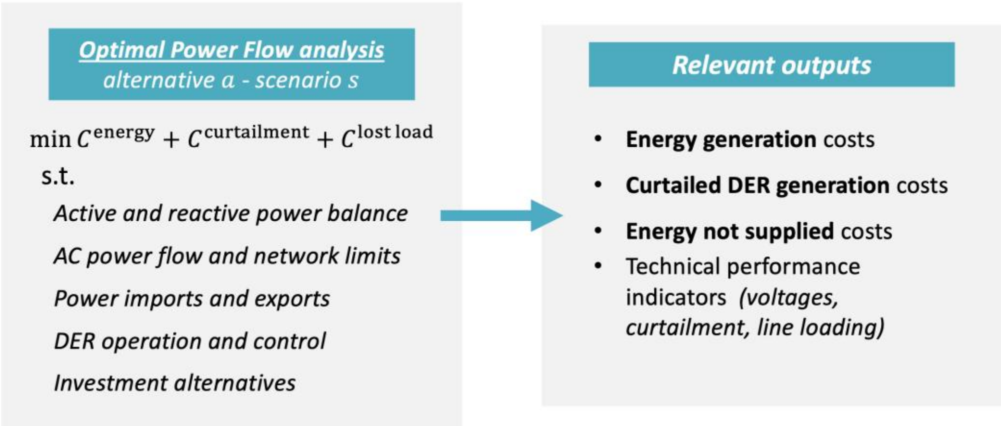

Figure 14: Optimal power flow constraints for techno-economic analysis of alternatives and relevant outputs.

Multi-criteria assessment using the decision-making framework **(Modules D – F)**

The power of the proposed framework lies in the possibility of analysing candidate alternatives using a variety of evaluation criteria, allowing for a holistic consideration of planning risks, costs and benefits. The following sections illustrate how the information generated in modules A, B, and C can be leveraged to iterate through different evaluation criteria, providing significant actionable insights to support the planner's final decision. For this case study, four assessment approaches, detailed in Table 16, are considered. Each approach involves selecting an *economic indicator*, a *decision-making functional* and a *decision criterion* in order to inform the planner.

Table 16: Assessment approaches considered for the illustrative case study application.

Assessment approach	**Economic Indicator** EI	**Decision-making functional**	**Decision-making criterion**	**Description**
#1 **Minimisation of expected cost**	Net present costs (NPC)	Scenario-weighted mean NPC: $\mathbb{E}(\mathrm{NPC},\Omega)$	Minimisation of scenario weighted mean NPC: $\mathrm{argmin}_{a\in\mathcal{A}}\mathbb{E}(\mathrm{NPC},\Omega)$	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 $(\max)$	Minimisation of the worst possible regret $\mathrm{argmin}_{a \in \mathcal{A}} \max \mathbb{R}(\mathrm{NPC})$	The decision maker would seek for the alternative(s) capable of minimising the worst (maximum) regret in terms of net present costs.
#3 **Minimisation of weighted regret (risks)**	Scenario-weighted regret of net present costs $\mathbb{R}(\mathrm{NPC}, \Omega)$	Worst outcome $(\max)$	Minimisation of the worst possible scenario-weighted regret $\mathrm{argmin}_{a \in \mathcal{A}} \max \mathbb{R}(\mathrm{NPC}, \Omega)$	The decision maker would seek for the alternative(s) capable of minimising the worst (maximum) scenario-weighted regret in terms of net present costs.
#4 **Minimisation of expected customer curtailment cost**	Cost of customer curtailment (CECV)	Scenario-weighted mean CECV: $\mathbb{E}(\mathrm{CECV}, \Omega)$	Minimisation of scenario weighted mean CECV $\mathrm{argmin}_{a \in \mathcal{A}} \mathbb{E}(\mathrm{CECV}, \Omega)$	The decision-maker would seek for the alternative(s) capable of minimising the scenario-weighted of customer curtailment cost.

Step #1: Computing economic indicators matrices

The initial step in applying the decision-making framework involves calculating matrices EI containing the economic indicators. These calculations are based on the results of the techno-economic evaluation (Module C), which assessed each alternative a across each scenario s.

- *(1) Net present cost*

The first economic indicator is the system net present cost (NPC). That is, the present value of the total annual costs incurred by the system throughout the entire planning horizon for each alternative a and scenario s. For this illustrative case, the NPC is composed of the discounted sum of annual operational expenditures (energy, curtailment and load not served)[11] and the annuitised capital costs for each investment option considered. Figure 15 provides a detailed breakdown of the composition of the economic indicator.

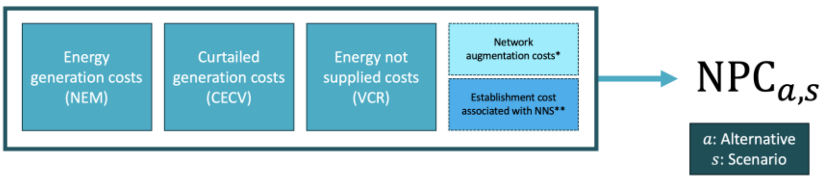

Figure 15: Composition of economic indicator net present costs (NPC).

The resulting matrix for this economic indicator, displaying $\mathrm{NPC}_{a,s}$ values for each of the seven alternatives and twenty scenarios, is presented in Table 17 (1).

- *(2) Regret of net present cost*

The second economic indicator is the regret of net present costs, denoted as $\mathbb{R}(\mathrm{NPC})$. This indicator represents the loss of efficiency (in terms of net present costs) that the planner could incur by

[11] NEM: National Electricity Market
CECV: Customer Export Curtailment Value
VCR: Value of Customer Reliability

choosing a suboptimal alternative for a specific scenario. It reflects the additional total system cost associated with selecting an alternative a that does not yield the minimum NPC in each scenario s. It is important to note that this economic indicator is obtained based on the NPC. By definition, the alternative with the lowest NPC in each scenario has a regret of zero. Hence, the regret in terms of NPC, for each alternative and scenario, $\mathbb{R}_{a,s}(\mathrm{NPC})$ is computed as indicated in Figure 16. The resulting matrix for this economic indicator is presented in Table 17 (2).

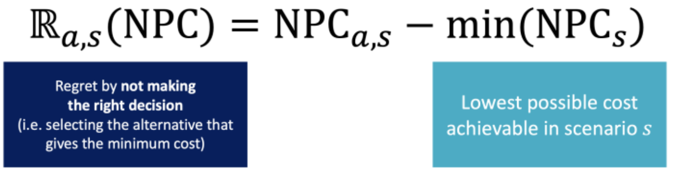

Figure 16: Composition of economic indicator regret of net present costs, $\mathbb{R}(NPC)$.

- <u>*(3) Scenario-weighted regret of net present cost*</u>

The third indicator for this multi-criteria assessment is the weighted regret of the net present costs, denoted as $\mathbb{R}(\mathrm{NPC}, \Omega)$. This indicator strategically incorporates the likelihood of each scenario, $\omega_s \subset \Omega$, as illustrated in Figure 17. By weighting the regret (the cost inefficiency of not selecting the lowest-cost alternative for a specific scenario) by the likelihood of that scenario occurring, this approach provides a measure of the expected opportunity loss associated with each alternative. The resulting matrix for this economic indicator is presented in Table 17 (3).

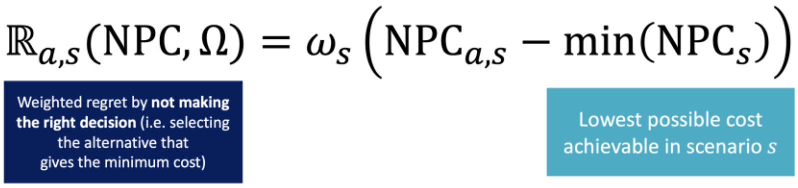

Figure 17: Composition of economic indicator weighted regret of net present costs, $\mathbb{R}(NPC, \Omega)$.

- <u>*(4) Customer curtailment cost*</u>

The fourth economic indicator for this assessment corresponds to the customer curtailment cost, denoted as CECV. This indicator captures, in present value terms, the economic detriment to consumers when the output of DER (e.g. rooftop PV generation) is curtailed. It allows for the assessment of the potential reduction in curtailment that the selection of a particular investment option could bring to the system, thereby benefiting consumers. The construction of this indicator is explained in Figure 18. The resulting matrix for this economic indicator is presented in Table 17 (4).

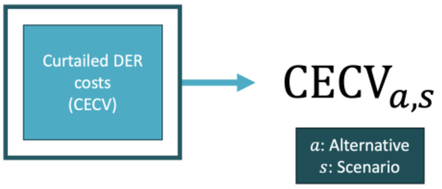

Figure 18: Composition of economic indicator customer curtailment cost, $CECV$.

Table 17: Computed economic indicators to inform decision-making

ECONOMIC INDICATOR MATRICES

(1) Net present cost

	ECONOMIC INDICATOR (EI) →			NET PRESENT TOTAL SYSTEM COSTS (NPC) - ($M AUD)																			
← ALTERNATIVES →	NETWORK AUGM.	#1	Netw. Aug. *Conductor type A*	719	729	740	748	752	719	729	740	748	752	719	729	740	748	752	744	754	764	813	838
		#2	Netw. Aug. *Conductor type B*	719	730	740	749	752	719	730	740	749	752	719	730	740	749	752	744	754	764	773	798
		#3	Netw. Aug. *Conductor type C*	718	728	739	748	751	718	728	739	748	751	718	728	739	748	751	742	752	762	807	832
	NON NETWORK SOLUTIONS	#4	Demand response (DR) *15 MW - 4 hr.*	708	718	727	736	739	708	718	728	736	740	725	813	856	894	898	708	718	727	736	739
		#5	Demand response (DR) *15 MW - 2 hr.*	708	763	772	781	784	736	862	931	1014	1017	822	948	1053	1173	1176	708	763	772	781	784
		#6	Demand response (DR) *10 MW - 4 hr.*	708	740	749	758	761	728	819	865	909	912	810	926	1008	1107	1112	708	740	749	758	761
		#7	Battery Storage (ESS) *37.5 MW - 4 hr.*	674	684	694	704	707	697	722	732	741	744	745	832	886	939	943	674	684	694	704	707
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 →	NETWORK AUGM.	#1	Netw. Aug. *Conductor type A*	80	80	80	79	79	56	42	42	42	42	8	1	1	1	1	105	104	104	144	165
		#2	Netw. Aug. *Conductor type B*	80	80	80	79	79	56	42	42	42	42	8	1	1	1	1	105	104	104	104	125
		#3	Netw. Aug. *Conductor type C*	79	79	79	78	78	55	41	41	41	41	7	0	0	0	0	103	103	103	138	159
	NON NETWORK SOLUTIONS	#4	Demand response (DR) *15 MW - 4 hr.*	69	68	67	66	66	45	31	30	30	30	14	84	117	146	146	69	68	67	66	66
		#5	Demand response (DR) *15 MW - 2 hr.*	69	113	113	112	111	73	175	234	307	307	111	219	315	425	425	69	113	113	112	111
		#6	Demand response (DR) *10 MW - 4 hr.*	69	90	90	88	88	65	131	167	202	202	99	198	270	359	360	69	90	90	88	88
		#7	Battery Storage (ESS) *37.5 MW - 4 hr.*	0	0	0	0	0	0	0	0	0	0	0	69	113	157	157	0	0	0	0	0
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 →	NETWORK AUGM.	#1	Netw. Aug. *Conductor type A*	11.42	11.41	11.39	11.30	11.29	0.80	0.60	0.60	0.60	0.60	0.11	0.01	0.01	0.01	0.01	2.99	2.98	2.98	4.10	4.70
		#2	Netw. Aug. *Conductor type B*	11.45	11.43	11.42	11.32	11.32	0.81	0.60	0.60	0.60	0.60	0.12	0.02	0.02	0.02	0.02	2.99	2.98	2.98	2.96	3.56
		#3	Netw. Aug. *Conductor type C*	11.29	11.28	11.27	11.17	11.16	0.79	0.59	0.59	0.59	0.59	0.10	0.00	0.00	0.00	0.00	2.94	2.94	2.93	3.93	4.53
	NON NETWORK SOLUTIONS	#4	Demand response (DR) *15 MW - 4 hr.*	9.85	9.73	9.64	9.46	9.44	0.65	0.44	0.43	0.42	0.42	0.20	1.20	1.67	2.09	2.09	1.97	1.95	1.93	1.89	1.89
		#5	Demand response (DR) *15 MW - 2 hr.*	9.83	16.20	16.10	15.93	15.91	1.04	2.49	3.34	4.39	4.39	1.58	3.13	4.49	6.08	6.07	1.97	3.24	3.22	3.19	3.18
		#6	Demand response (DR) *10 MW - 4 hr.*	9.83	12.89	12.80	12.63	12.60	0.93	1.88	2.39	2.89	2.89	1.41	2.82	3.85	5.13	5.15	1.97	2.58	2.56	2.53	2.52
		#7	Battery Storage (ESS) *37.5 MW - 4 hr.*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.98	1.61	2.24	2.24	0.00	0.00	0.00	0.00	0.00
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 CURTAILMENT COST - ($M AUD)																			
← ALTERNATIVES →	NETWORK AUGM.	#1	Netw. Aug. *Conductor type A*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
		#2	Netw. Aug. *Conductor type B*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
		#3	Netw. Aug. *Conductor type C*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
	NON NETWORK SOLUTIONS	#4	Demand response (DR) *15 MW - 4 hr.*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
		#5	Demand response (DR) *15 MW - 2 hr.*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
		#6	Demand response (DR) *10 MW - 4 hr.*	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.57	1.57	1.57	1.57	1.57	1.57	1.56	1.56	1.56	1.56	1.56
		#7	Battery Storage (ESS) *37.5 MW - 4 hr.*	1.46	1.46	1.46	1.45	1.45	1.45	1.45	1.45	1.45	1.55	1.55	1.55	1.55	1.55	1.55	1.56	1.56	1.56	1.55	1.55
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*				

Step #2: Computing decision-making functionals over economic indicator matrices

The second step in applying the decision-making framework involves employing a suite of decision-making functionals. These functionals are specifically used to process the numbers within each economic indicator matrix (derived in Step #1) into a single, informative and interpretable result for each alternative a across the spectrum of considered scenarios s. In this case study, the following decision-making functionals are employed for this purpose:

- **(A)** *Scenario-weighted mean (expected value) of net present cost: Applied in matrix (1)*
- **(B)** *Worst regret of net present cost: Applied in matrix (2)*
- **(C)** *Worst regret of weighted net present cost: Applied in matrix (3)*
- **(D)** *Scenario-weighted mean (expected value) of customer curtailment cost: Applied in matrix (4)*

Once the appropriate calculations have been performed, the resulting figures are synthesised in Table 18. The table illustrates the output of each decision-making functional when applied to a particular economic indicator. For example, for alternative #1, the application of the worst (maximum) value on the regrets of NPC (column B) results in a figure of $M 164.61 AUD.

Table 18: Outcomes of applying each decision-making functional to the economic indicator.

		DECISION-MAKING FUNCTIONAL			
ALTERNATIVES		**(A)** *Scenario-weighted mean* NPC *($M AUD)*	**(B)** *Worst regret of* NPC *($M AUD)*	**(C)** *Worst weighted regret of* NPC *($M AUD)*	**(D)** *Scenario-weighted mean curtailment cost ($M AUD)*
#1	**Network augmentation** *Conductor type A*	744.12	164.61	11.42	1.56
#2	**Network augmentation** *Conductor type B*	741.96	124.56	11.45	1.56
#3	**Network augmentation** *Conductor type C*	742.86	158.56	11.29	1.56
#4	**Demand response** (DR) *15 MW - 4 hr.*	733.51	146.49	9.85	1.56
#5	**Demand response** (DR) *15 MW - 2 hr.*	791.95	425.28	16.20	1.56
#6	**Demand response** (DR) *10 MW - 4 hr.*	768.41	360.43	12.89	1.56
#7	**Battery Storage** (ESS) *37.5 MW - 4 hr.*	707.60	157.03	2.24	1.55

Step #3: Application of decision theory criteria to select and review preferred alternatives

The third step in the framework is to use the defined decision criteria to evaluate the summarised results from Step #2. This helps identify the best alternative based on each criterion and points out potential planning risks for the decision-maker choosing that option. Table 19 summarises and ranks the candidate alternatives (1-7) based on the application of each decision criterion to the computed functionals (A-D).

Table 19: Summary of decision-making criteria for the illustrative case study

		DECISION CRITERIA SUMMARY			
ALTERNATIVES		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 augmentation** *Conductor type A*	744.12	164.61	11.42	1.56
#2	**Network augmentation** *Conductor type B*	*741.96*	**124.56**	*11.45*	*1.56*
#3	**Network augmentation** *Conductor type C*	742.86	158.56	11.29	1.56
#4	**Demand response** (DR) *15 MW - 4 hr.*	**733.51**	**146.49**	**9.85**	**1.56**
#5	**Demand response** (DR) *15 MW - 2 hr.*	791.95	425.28	16.20	1.56
#6	**Demand response** (DR) *10 MW - 4 hr.*	768.41	360.43	12.89	1.56
#7	**Battery Storage** (ESS) *37.5 MW - 4 hr.*	**707.60**	*157.03*	**2.24**	**1.55**

1st best alternative for a given criterion
2nd best alternative for a given criterion
Result of a "best" alternative using another criterion (potential regret)

As can be observed in Table 19, the preferred alternative varies significantly depending on the criterion prioritised. For instance, if the primary objective is to minimise expected total costs (criterion A), installing the storage system (alternative 7) emerges as the most favourable choice. This underscores the potential for non-network solutions to offer significant cost savings under certain operational and economic conditions.

A key strength of this framework is its ability to immediately quantify the potential planning risks associated with a suboptimal decision by examining the other decision criteria. For the choice made using criterion A (minimisation of expected total NPC), it is seen that if criterion B is revised, the planner could experience greater regret by selecting the battery system (alternative 7) as this alternative does not rank first for that criterion. This is because in the approach of minimising absolute regret (criterion B), the network augmentation using a type B conductor (AAC 19/4.75) becomes the preferred alternative, highlighting a potential trade-off between expected cost and worst regret.

When the remaining two criteria are considered: minimisation of scenario-weighted regret (criterion C) and minimisation of customer curtailment cost (criterion D), the battery storage system (alternative 7) consistently ranks as the top-performing alternative. This consistency across criteria that consider different aspects of risk and operational performance reinforces the robustness and potential suitability of the decision made based on minimising expected total costs (criterion A), suggesting it may be a strong contender even when other priorities are factored in.

If a planner adopts a more conservative, risk-averse stance and prioritises minimising the maximum potential regret across all considered scenarios (criterion B), network augmentation with a type 2 conductor (alternative 3) is identified as the most suitable planning decision. Nonetheless, a review of this alternative's performance against the other criteria reveals potential inefficiencies. For example, under the cost-minimising criterion A, the alternative ranks third, and its performance further declines to fifth under the scenario-weighted regret criterion C, whilst achieving a second-best ranking for customer curtailment cost (criterion D). This starkly illustrates the critical importance of incorporating multiple evaluation criteria into the decision-making process to avoid seemingly safe but ultimately suboptimal planning decisions that may lead to higher costs or increased risks in other dimensions.

Another noteworthy planning alternative is the deployment of 15 MW of demand response for four hours (alternative 4). As clearly presented in Table 15, this alternative demonstrates a remarkable consistency, consistently ranking second across all four decision criteria. Whilst it does not achieve the top performance in any single criterion, this stability and balanced performance profile may be particularly appealing to planners seeking robust and reliable planning alternatives that offer a good compromise across various objectives and risk appetites. This highlights the value of considering alternatives that offer consistent, albeit not maximal, benefits across different priorities.

A crucial element of informed investment planning decision-making is the ability to effectively compare the relative merits of different alternatives against a range of evaluation criteria. To facilitate this critical comparison, a clear visual representation of each alternative's performance across each criterion is essential. Figure 19 serves this purpose, providing a concise summary of the evaluation of the different alternatives and decision criteria. This visual aid readily illustrates to the planner the potential trade-offs or inefficiencies that might arise in terms of other important objectives depending on the specific planning decision ultimately made, enabling a more holistic and well-informed final selection.

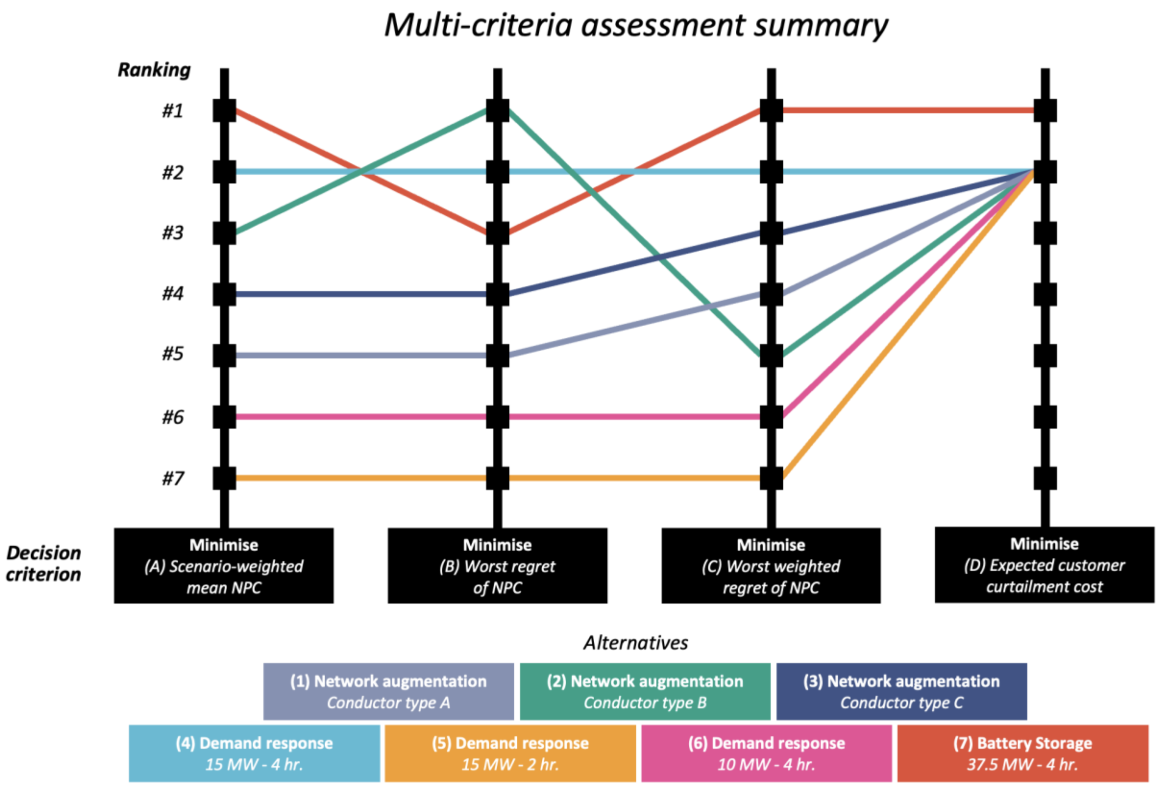

Figure 19: Integrated visualisation of the multi-criteria assessment results

Determining the value of non-network alternatives

A primary consideration when assessing non-network solutions as planning alternatives is the operational payment required for their activation. As the multi-criteria evaluation in Figure 19 illustrates, a non-network alternative can offer greater benefits in certain scenarios. Consequently, should such an alternative be preferred, the planner may need to establish an operational payment scheme to adequately remunerate the activations of the selected option.

Ultimately, the level of payment, budget, or ceiling price for a specific alternative will be constrained by the benefits that said alternative provides to the system when compared against a *business-as-usual* case or with other network alternatives suitable for addressing the same system need. This ensures that the remuneration is economically justifiable.

In this case study, the battery system (alternative 7), the network reinforcement using type 2 conductors (alternative 2), and the 15 MW demand response for 4 hours (alternative 4) clearly emerge as the most promising options based on the evaluation criteria. However, alternative 7 demonstrates a better average ranking. Given this, and the fact that alternative 7 avoids the need for committed network augmentation while also offering economic advantages (lower net present cost as well as reduced customer curtailment), a proxy for an estimated payment for its installation and/or activation can be derived by measuring the additional benefits it offers compared to reinforcing the grid using alternative 2.

To conduct this assessment, the results from the functional (A) are employed. This functional quantifies the total expected costs of the system with the implementation of each alternative: $\mathbb{E}_a(\mathrm{NPC})$. Thus, $\mathcal{V}_7$ in calculation (1) determines the present value of the benefits of the storage system over the reinforcement of the network (i.e., an estimate of the value of this alternative). Subsequently, based on this, calculation (2) derives the annuity of these benefits using a discount rate of 7% over a period of 5 years, concluding that an annual remuneration of up to A$ 8.38 million (for the construction, installation, and operation of the storage system) could be economically beneficial when compared to reinforcing the network.

$$\mathcal{V}_7 = \mathbb{E}_2(\mathrm{NPC}) - \mathbb{E}_7(\mathrm{NPC}) = 741.96 - 707.60 = \mathrm{A\$}\ 34.36\ \mathrm{M} \tag{1}$$

$$\mathbb{A}_7^{yr} = \frac{34.36 \cdot 0.07}{1 - (1 + 0.07)^{-5}} = \mathrm{A\$}\ 8.38\ \mathrm{M} \tag{2}$$

As the evaluation results in Figure 19 indicate, alternative 4 may also be attractive to certain planners. Under this premise, this alternative would also enable the avoidance of network reinforcement (alternative 2) while simultaneously providing economic benefits. The calculation performed in (3) quantifies the economic value $\mathcal{V}_4$ of this alternative compared to reinforcing the network. Calculation (4) then derives the corresponding absolute annuity for this alternative. Finally, through (5), a proxy for the payment for demand response capacity can be obtained. This value is obtained based on the capacity $(\mathrm{DR}^{\mathrm{Capacity}})$ and duration $(\mathrm{DR}^{\mathrm{Duration}})$ of the response and parameterised with the number of expected activations in a year, $n_{yr}^{\mathrm{activations}}$. It is important to emphasise that this value already incorporates the reduced potential benefits due to a potentially lower availability of the alternative given its non-network nature.

$$\mathcal{V}_4 = \mathbb{E}_2(\mathrm{NPC}) - \mathbb{E}_4(\mathrm{NPC}) = 741.96 - 733.51 = \mathrm{A\$}\ 8.45\ \mathrm{M} \tag{3}$$

$$\mathbb{A}_4^{yr} = \frac{34.36 \cdot 0.07}{1 - (1 + 0.07)^{-5}} = \mathrm{A\$}\ 2.06\ \mathrm{M} \tag{4}$$

$$\mathbb{A}_4^{yr-\mathrm{MWh}} = \frac{\mathbb{A}_4^{yr}}{\mathrm{DR}^{\mathrm{Capacity}} \cdot \mathrm{DR}^{\mathrm{Duration}} \cdot n^{\mathrm{activations}}} = \frac{\mathrm{A\$}2.06\ \mathrm{M}}{15 \cdot 4 \cdot n_{yr}^{\mathrm{activations}}} = \frac{\mathrm{A\$}\ 34{,}333}{n_{yr}^{\mathrm{activations}}} \tag{5}$$

b. **Case #2:** Victorian case study to assess demand-side flexibility in distribution networks – CBTS

The second case study is presented in this section. It 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 9, Tables Table 10 and Table 11. A ten-year planning horizon, beginning in 2040, is selected to align with the minimum planning horizon required by the NER. The scenario design follows the exact same trends, likelihoods and particular risks incorporated for case study #1.

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 Table 20. 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.

Table 20: Set of alternatives for the CBTS sub-transmission network case study application.

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)

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 21 presents the economic indicators used in this case study, which are consistent with those applied in Case Study #1. Subsequently, Table 22 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 20 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.

Table 21: Computed economic indicators to inform decision-making – CBTS case study application.

ECONOMIC INDICATOR MATRICES

(1) Net present cost

← ALTERNATIVES →	ECONOMIC INDICATOR (EI) →	TOTAL SYSTEM NET PRESENT COST (NPC) - $M AUD																			
#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

← ALTERNATIVES →	ECONOMIC INDICATOR (EI) →	REGRET OF NET PRESENT TOTAL SYSTEM COSTS - ($M AUD)																			
#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

← ALTERNATIVES →	ECONOMIC INDICATOR (EI) →	SCENARIO-WEIGHTED REGRET OF NET PRESENT COSTS - ($M AUD)																			
#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

← ALTERNATIVES →	ECONOMIC INDICATOR (EI) →	TOTAL CUSTOMER EXPORT CURTAILMENT COST (CECV) - $M AUD																			
#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 22: Summary of decision-making criteria for the case study – CBTS case study application

		DECISION CRITERIA SUMMARY			
ALTERNATIVES		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

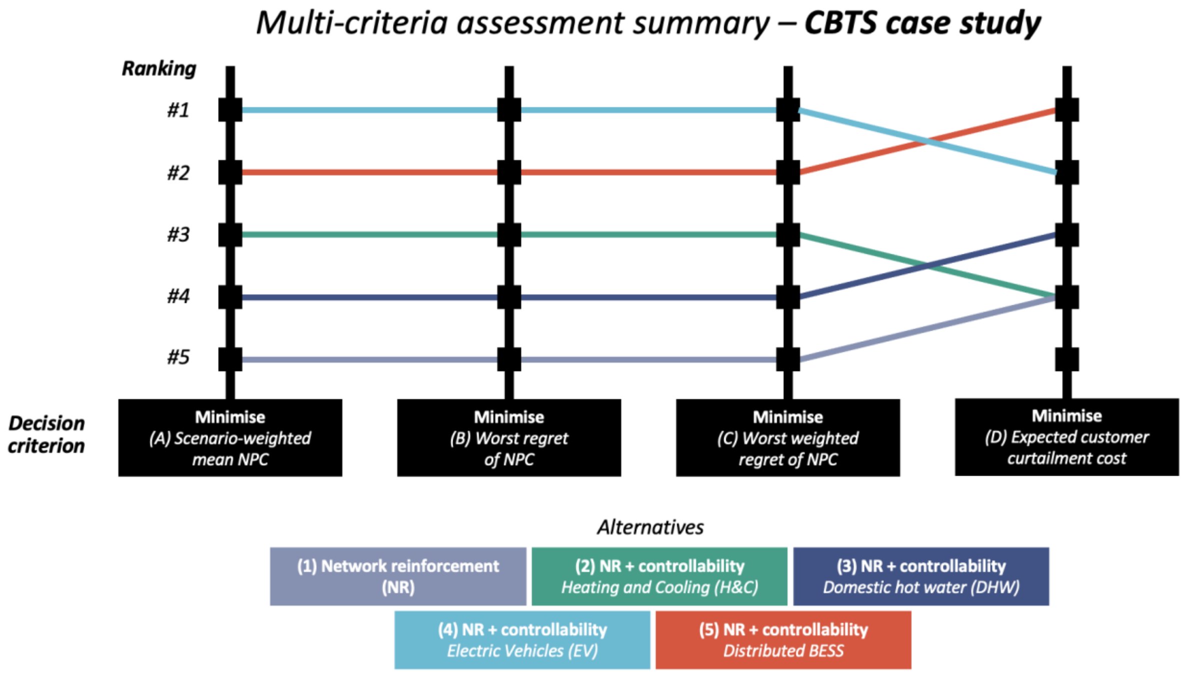

Figure 20: Integrated visualisation of the multi-criteria assessment results - CBTS case study application.

c. Key takeaways

The following key takeaways aim to succinctly outline the main strengths of the developed decision-making framework and highlight how the results of the case studies contribute to demonstrate these advantages, 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 stakeholders 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.

6. Conclusions and recommendations

This project proposes a comprehensive decision-making methodology for uncertainty-aware investment planning in distribution systems, with a specific focus on enhancing the valuation of non-network options and addressing planning risks (potential inefficient investment decisions). This approach is rooted in established decision theory principles, enabling a comprehensive multi-criteria assessment of investment alternatives across various scenarios, sensitivities, and planning horizons.

The proposed framework offers several key advantages for Distribution Network Service Providers (DNSPs) and other stakeholders. Its adaptability across all network voltage levels and scalability to various project sizes ensure broad applicability. The modular architecture facilitates efficient collaboration and parallel work streams of teams within an organisation. Its straightforward implementation, leveraging standard spreadsheet software for key analytical steps, ensures practical accessibility.

This enhanced planning approach is critically needed due to the profound transformation of distribution systems, particularly in Australia, driven by the rapid uptake of distributed energy resources (DER) and increasing electrification. This dynamic landscape introduces significant uncertainties that can lead to substantial risks, such as inefficient network over-investment and stranded assets, ultimately increasing costs for consumers. Traditional, single-scenario planning methodologies often struggle to navigate this complexity, leading to suboptimal decisions and underestimating the valuable role that flexible, non-network solutions can play.

In particular, a key real-world challenge in decision-making under uncertainty involving a wide range of stakeholders is formulating and communicating complex investment choices. In the context of Australian distribution systems, such decisions often involve not only DNSPs but also consumers, governments, regulators, and private investors, among others. In this regard, adopting the methodological principles outlined in this report 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.

In summary, this project provides a practical and theoretically sound decision-making methodology that equips stakeholders with the technical principles to navigate the increasing uncertainties of modern distribution system planning. By promoting a comprehensive, multi-criteria, scenario-based evaluation with a specific focus on the valuation and integration of non-network solutions, this framework facilitates the evaluation of more robust and strategic investment decisions for Australian distribution systems.

Glossary of terms

Non-network solution/option/alternative	Asset, resource or strategy that can address a specific network constraint without relying on traditional infrastructure upgrades or augmentations (i.e., line or transformer replacement, augmentation or upgrade).

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