Investment Coupled Whole-System Planning

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Report for C4NET

Project Consortium

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Executive Summary

The widespread deployment of small-scale assets (e.g., electric vehicles, distributed storage, distributed generation) is introducing additional uncertainty within power systems, but also, they increase the coordination within distribution networks along with the ability of customers to take control over their own energy demand, opening new value streams for them. These new interactions and the transition from passive to active distribution networks are spreading decision-making across multiple levels, increasing the complexity of power system planning. A clear example of this trend is the Australian power system, where the Australian Energy Market Operator (AEMO) expects that if Consumer Energy Resources (CER) are effectively coordinated, up to $4.1 billion in large-scale investments could be avoided.

However, most system planners neglect decision-making over CER, and more broadly Distributed Energy Resources (DER), usually considering them as an inherent feature of analysed scenarios, as well as the limitations and investments needed within distribution networks to support such technologies. In turn, this could lead to inaccurate assessments on the value provided by DER, as well as in inefficient and conflicting investments across the system, and although joint planning arrangements between transmission and distribution systems are encouraged in Australia under the National Electricity Rules, such process comes after the Integrated System Plan (ISP) optimally decides the transmission augmentation needs.

Thus, ***decision-making over transmission and distribution systems is an independent process***, hence, to make better and more efficient investment decisions across the whole system and truly capture the value of CER, the coordination within planning must be improved. In this sense, a literature review was conducted in this report to analyse the proposed methodologies to coordinate integrated planning frameworks between transmission and distribution systems.

Four main methodologies are identified. A **centralised approach** hinges on one entity having full knowledge over the whole system (e.g., resources, constraints, etc.) and thus, has the potential to find the best possible solution. A **multi-level approach** considers a multi-objective problem, leveraging Karush-Kuhn-Tucker (KKT) conditions and strong-duality theorem to reformulate it into a single-level one but it does not remove the need for having full knowledge of the system. However, both approaches are the most difficult to apply in a real-world context due to the huge data that needs to be exchanged and compiled into a large-scale optimisation problem, resulting in high computational burden.

Such challenges are removed with distributed decision-making. An **iterative approach** communicates transmission and distribution planning problems by a reduced set of variables at the interface, nevertheless, it hinges on a simultaneous solving methodology (both problems are solved at the same time) and thus, such an approach would be difficult to manage in real-world applications as it requires multiple instances of communication. Following the same communication scheme, **decoupled approaches** are an emerging methodology that decouples integrated frameworks in a sequential decision-making process (no need for parallel solving), allowing for coordinating system planners sequentially with a reduced set of variables or even, surrogate representations (e.g., distribution planning scenarios within transmission planning problem).

In this context, ***distributed decision-making*** has the potential to provide efficient coordination and scalable formulations for integrated planning problems without compromising the quality of solutions and thus, appear as the most suitable methodology for real-world applications, because transmission and distribution planners, under their current roles, could use their own tools to share information.

Following these principles of communication, a bottom-up methodology is proposed in this work package. This approach aims at producing a parametric representation of the investments required (e.g., active network management, distributed storage, network reinforcements) to support DER adoption at multiple levels of in distribution networks, communicating this from LV networks up to HV or subtransmission level, allowing to hierarchically inform distribution investments for system planners to consider within transmission planning frameworks, enhancing coordination.

In this context, such representation could be produced by any DNSP with their own tools, understanding the limitations of their networks and the subsequent investments that would be needed to unlock distributed resources and operational flexibility (e.g., dynamic operating envelopes, equivalent models, etc.), and inform them to system planners such as AEMO in the Australian case. This would enhance the planning coordination in an efficient manner from bottom-up and in turn, it would help in making better investment decisions across the whole system.

Case studies reveal the effectiveness of this methodology to understand the importance of proactively planning distribution networks jointly with the connection of DER, as well as active network management, aspects that could make distributed resources more competitive against larger scale developments (connected to the transmission network). Additionally, the value of coordinating CER is also explored by analysing the behaviour of investment cost functions when going from 0% to 100% of coordination over expected resources. Fully exploiting CER coordination provides huge benefits for planning distribution networks, nevertheless to fully assess both investments and how much capacity can be leveraged at the higher voltage levels such as subtransmission or transmission systems, the impact on MV-LV networks and the added complexity involved in coordinating large numbers of small-scale resources (need for aggregation), which will be governed by customer preferences, need to be accounted for. These aspects can be further explored with the proposed methodology.

In this sense, there will be trade-offs between the provision of local services and investments in network reinforcements, as DNSPs could plan distribution networks by minimising costs, leveraging CER coordination to reduce investments, or even communicate future portfolios where additional investments are in place for this CER to provide services upstream the system at the national level (e.g., transmission system), which may not be the minimum cost solution for the distribution system but rather for the whole system (unlocking huge value at the transmission level).

Moreover, the integration of this methodology in a whole system planning framework was assessed, showing how and what information could be produced by DNSPs and communicated to system planners. Case studies focused on trade-offs between large-scale and small-scale resources, and on the value that CER coordination could unlock for the whole system. The main insights are the following:

- Enabling DER investments within active distribution networks can displace or defer both transmission augmentation and large-scale renewables development. Particularly when analysing the integration of these resources within subtransmission networks, demonstrating that a whole-system decision-making approach could schedule and allocate resources more efficiently.
- The impact of CER coordination can reduce the total system costs (investment and operational costs), mainly due to deferred large-scale transmission and distribution investments. This was analysed for a small representation of the NEM, using ***synthetic networks to represent the distribution systems for each subregion modelled for New South Wales in the ISP***.

Although these case studies show promising and encouraging results towards an investment coupled whole system planning framework, ***proper representations of distribution systems must be in place (e.g., network limitations) for their proper integration at a national level, and to realise such a framework in the real world***. Thus, the quantification of benefits presented in this work are not representative but rather, show the steps on how and what information must be communicated for the real-world applicability of an investment coupled whole system planning framework. Based on this, DNSPs from each state would be able to produce parametric investment cost functions, and the operational capabilities unlocked by these investments, across all levels of their distribution networks, using their own tools and know-how capabilities.

Glossary of Terms / Abbreviations

AEMO	Australian Energy Market Operator
ISP	Integrated System Planning
CER	Consumer Energy Resources
DER	Distributed Energy Resources
TNSP	Transmission Network Service Provider
DNSP	Distribution Network Service Provider
ADN	Active Distribution Networks
ADS	Active Distribution Systems
TEP	Transmission Expansion Planning
DEP	Distribution Expansion Planning
ITDEP	Integrated Transmission and Distribution Expansion Planning
EV	Electric Vehicles
DR	Demand Response

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1. Project Overview

a. Background

Power system planning aims to find cost-effective and reliable investments for the future. However, this problem is increasing in complexity due to new interactions and the integration of new technologies that increase the variability of supply, flexibility requirements, and spread decision-making across multiple levels. In particular, the widespread deployment of small-scale assets, while increasing the uncertainty of demand profiles, also offers the prospect of increased coordination within distribution networks (e.g., demand response, electric vehicles, distributed storage) and the ability of customers to take control over their own energy demand. Consequently, there is a transition from passive to active distribution networks that will decentralise and impact the planning of power systems worldwide [1].

A clear example of this trend is Australia's case. The Australian Energy Market Operator (AEMO), as depicted in Figure 1-1, is expecting that a big portion of the available assets by 2050 will be in distribution networks in the form of CER storage, rooftop and distributed solar, and demand-side participation. In addition, AEMO estimates that $4.1 billion in large-scale investments could be avoided if such resources are effectively coordinated [2].

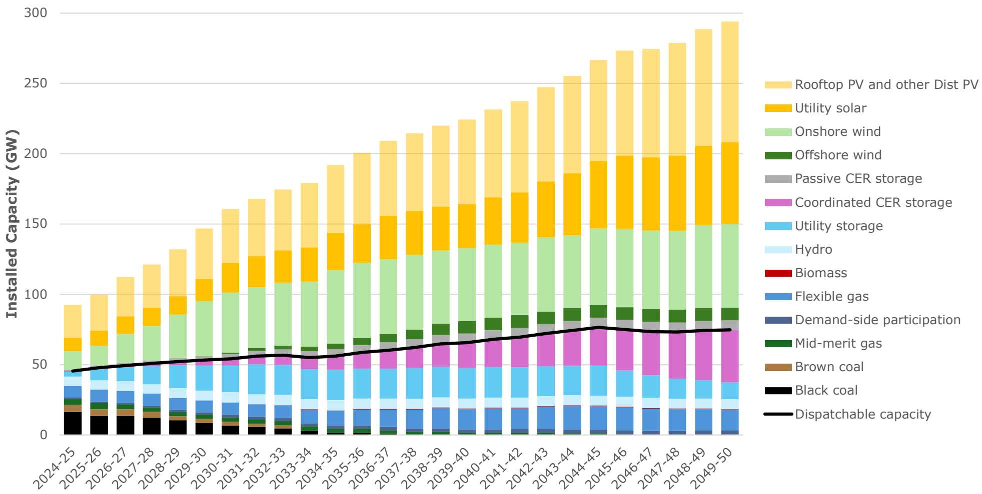


Figure 1-1: Expected Installed Capacity, ISP Step-Change Scenario [2]

In this regard, consumer energy resources (CER) and more broadly, distributed energy resources (DER), have the potential to impact planning, deferring, or complementing costly infrastructure investments. Assets like demand response (DR), electric vehicles (EV), distributed generation (DG), storage, and aggregated resources as virtual power plants (VPP) increase the coordination of the demand side, enhancing the whole-system flexibility [3], [4], [5]. Consequently, active distribution networks (ADNs) will be key to facilitate strong supply-demand linkages through proper investment decisions to support CER, and its coordination.

Nevertheless, current power system planning practices often neglect decision-making over DER by considering them as an inherent feature of the analysed scenarios in planning processes, and the limitations and investments within distribution networks [6]. Thus, mechanisms to adequately assess and quantify the investments needed at the distribution level to unlock DER's operational flexibility are not accounted for, missing out on trade-offs between large- and small-scale investments. In turn, this may lead to inaccurate assessments on the value provided by these resources, and inefficient and conflicting investments across the system [7]. Moreover, although these challenges have been identified by power system planners across the world, particularly in the UK and Australia [8], [9], there is yet to find an integrated planning framework within the real world.

In this vein, a paradigm shift is needed in planning frameworks and integrating ADNs as investment opportunities within an integrated planning process, could be key to providing insights on where is more convenient to develop power systems (e.g., large- or small-scale developments). Nevertheless, the lack of coordination and standardised data exchange protocols due to differing scales and scopes between system operators, and the computational challenges of large-scale optimisation formulations, hinder an integrated planning process.

Therefore, to bridge this gap, regulators must improve the planning process of transmission and distribution systems aiming at finding more robust and cost-effective solutions [10]. Thus, alignments between decision-makers, improved coordination schemes, and new planning tools and methodologies will be crucial to find more efficient development paths for the future and in turn, orchestrate an *integrated transmission and distribution expansion planning* (ITDEP). In this sense, a methodology was developed and tested to showcase the value that could be unlocked from ITDEP frameworks.

Based on this, this report outlines the main findings from integrating transmission and distribution planning, particularly how flexibility is a suitable alternative for deferring traditional investments in power systems and could open the possibility for additional distributed resources to compete against large-scale investments. This report also identifies the key challenges of coordination methodologies from the literature that support the practical implementation of the proposed methodology in the context of the Enhanced System Planning (ESP) project from C4NET, and particularly for work package 3.13, Investment Coupled Whole-System Planning.

b. Aims and Objectives

WP 3.13 "Investment Coupled Whole-System Planning", as part of C4NET Enhanced Systems Planning (ESP), aims to:

- Develop a methodological framework that integrates the planning of transmission and active distribution systems.
- Asses large- and small-scale investment trade-offs across the whole-system in the presence of active distribution systems.

Overall, WP3.13 will provide methodological steps to represent the planning of active distribution systems within a whole system planning framework. In this sense, any DNSP, will be able to replicate this methodology using their own tools and in turn, provide investment paths as a reduced amount of information to AEMO, facilitating the decision-making process of the whole system. This in turn, will allow to identify the main drivers that shift the development of the Australian power system towards large- and small-scale developments.

c. Key Milestones

The key milestones of this work package, their timelines, and the corresponding contents are further detailed bellow.

Milestone 1: Literature Review (September 2024)

Overview of approaches for coordinating the planning of transmission and distribution systems, providing recommendations on the methodology to be adopted for Milestone 2

Milestone 2: Modelling and Planning Methodologies (November 2024)

A detailed presentation, showing the methodological principles in place for this work package, that allow for efficient coordination of transmission and distribution networks within planning.

Milestone 3: Assessment of trade-offs (February 2025)

A detailed presentation, highlighting the potential of multiple technologies to reduce the impact of electrification by supporting the adoption of DER and its coordination, improving decision-making across the whole system.

Milestone 4: Final Report (March 2025)

A final report presenting the findings of the 10-month project WP 3.13, including a summary of inputs, assumptions, as well as results from case studies.

2. Integrated Whole-System Planning

a. Real-world Context

Integrated planning frameworks are challenging to orchestrate mainly due to computational burden (e.g., increasing variables and constraints), the lack of coordination, and vast differences in scale and scope between transmission and distribution systems, but have the potential to truly achieve better techno-economic value. However, there are no real-world examples where such a framework is in place, nevertheless there is increasing interest in improving this coordination as well as allowing DER to participate in whole-system markets.

In the USA, the Federal Energy Regulatory Commission (FERC) oversees wholesale electricity markets and investments in transmission systems, where the latter is carried out by Regional Transmission Organisations and Independent System Operators for at least three distinct long-term scenarios and no less than a 20-year planning horizon [11]. However, there is no coordination with distribution systems, as the planning of these is regulated within each state independently by Public Utility Commissions. Despite that, the FERC has arrangements in place for DER to participate in electricity markets through aggregators, who share compensation back to individual DER [12].

A similar situation can be found across Europe. The European Network of Transmission System Operators for Electricity coordinates the transmission planning across Europe through the Ten-Year Network Development Plan, working closely with TSOs to ensure that investment portfolios meet national and EU-wide goals, while DSOs are responsible for distribution planning at a local level [13]. Moreover, in terms of coordination, the Clean Energy Package identified the need for improving coordination mechanisms due to the growth of DER and extend this to planning [14].

Under this context, UK is one of the most advanced countries in Europe regarding regulatory aspects for DER adoption. Even though distribution planning is handled locally by DSOs, the Office of Gas and Electricity Markets, the entity that regulates the planning of transmission networks, increased the emphasis on flexibility services and cooperation between system operators to manage DERs and demand response, identifying the need for improving the coordination within planning [15], [16].

Furthermore, in Australia, the Integrated System Planning (ISP) serves as a roadmap for the energy transition of the National Energy Market (NEM). It outlines a clear path for infrastructure investments at the transmission level to meet future energy needs. The ISP adopts an iterative and multi-module approach with interactions between modelled inputs, gas supply model, engineering assessments, capacity outlook model (e.g., generation and transmission expansion, dispatch, retirements, etc.), time-sequential model, and cost-benefit analyses to test scenarios and development plans [17].

Particularly, AEMO expects a huge uptake of CER within their projected scenarios and quantified that, if such resources are properly coordinated, up to $4.1 billion in large-scale infrastructure could be saved. Nonetheless, the ISP focusses on transmission-level investments, neglecting the investments needed in distribution networks to support these scenarios, nor the investment and operational costs associated to DER and CER.

This creates a gap where trade-offs between large- and small-scale assets are not properly captured. Despite the encouragement of joint planning arrangements between Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSP) under the National Electricity Rules in the form of Regulatory Investment Test (RIT)[1] [18], this process comes after the ISP as shown in Figure 2-1, meaning that distribution planning is assessed independently and hence, this process may potentially lead to suboptimal investment decisions across the power system. Therefore, improving the coordination between transmission and distribution planning processes could be key to achieving more efficient and cost-effective outcomes in the context of Australia's energy transition.

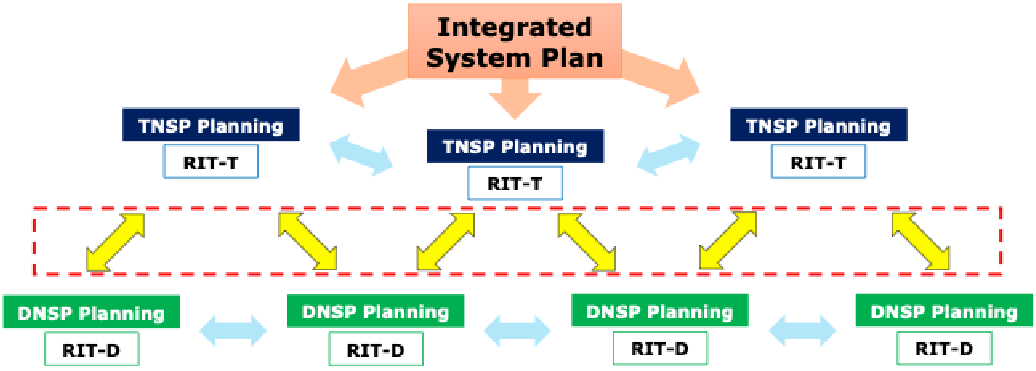


Figure 2-1: Coordination within planning of Australian power system. Red arrows indicate possible coordination between TNSP and DNSP planning

From an operation perspective, various Australian projects have aimed at enhancing the integration and market participation of DER, making significant efforts to advance this topic from a whole-system point of view. **Project EDGE** focused on aggregating DER as VPPs to provide services into the NEM, conducting live trials in Victoria's Hume region that allowed enhancing customer participation [19]. Likewise, **project Edith** offers a path for fairer pricing for customers by proposing a dynamic pricing methodology based on network charges on the actual conditions for a particular customer at a specific time and location [20], [21]. Using the same VPP aggregation strategy, **project Symphony** was designed to coordinate approximately 900 DER assets within 500 households and businesses in Western Australia [22]. Furthermore, **project Converge** is an initiative that focussed on improving DER integration to provide network support services through enhanced data and communication technologies, maximising their value in energy and Frequency Control Ancillary Services (FCAS) markets [23].

Despite Australia being one of the most advanced countries in DER adoption, these projects have identified several challenges such as technical integration, market and regulatory frameworks, consumer engagement, data communication, and stronger connections between industry needs and

[1] Process to identify the investment option that maximises net economic benefits, from the TNSP or DNSP perspective, according to the augmentation needs that were optimally found in the ISP

trial learnings [24]. All these need to be addressed for enhancing the coordination and shift towards a whole-system perspective, and truly value DER services, open market-based opportunities, and find a cost-effective development for the future system [25].

Finally, Canada is one of the few countries in which coordination between transmission and distribution within planning is in place. However, this only occurs at a regional level as there is no national planning framework in Canada. In Ontario, there is coordination between Alectra Utilities (distribution utility), Hydro One (TSO), and the independent electricity system operator (IESO) [26], where jurisdiction agreements allow for an *integrated regional resource planning* process that evaluates various options (generation, transmission, distribution, energy storage, and demand-side management) to meet regional electricity needs in a reliable and cost-effective manner over a long-term planning horizon (10-20 years). Thus, it coordinates the decision-making of transmission and distribution networks to develop a plan that integrates a variety of resource options to address the electricity needs of the region [27].

b. Overview of Coordinated Planning Methodologies

Having a clear understanding that planning of transmission and distribution networks are often independent and lack decision-making coordination within a real-world context, the objective of this section is to overview the modelling approaches proposed in the literature to tackle ITDEP with particular focus on how system operators coordinate and solve such problem, identifying the most suitable approaches for real-world implementation.

i. Centralised Scheme

This approach is formulated with a single objective function that minimises investment and operational costs of the whole system and therefore, it works under the key assumption that the planning entity has full knowledge over networks and allocation of resources across all levels of the system. In this sense, it is suitable when the system planner entity has jurisdiction over the whole system as it happens in Ontario, Canada.

The most common analysis under this approach is a comparison with uncoordinated approaches (independent planning processes), concluding potential reductions on the total network expansion costs. Such insights have been provided with deterministic formulations that include the impact of BESS as investment options [28], [29], while stochastic formulations have been proposed as well to account for degrees of uncertainty, analysing additional benefits with decision-making over DGs [30], and improvements in reliability indicators [31].

However, the effectiveness of centralised approaches hinges on perfect data availability across the whole system, which is often not feasible nor within regulatory frameworks, and hence real-world applications leveraging this methodology would be difficult to achieve. What is more, this approach usually comes at the expense of complex and intractable formulations, often needing assumptions on uncertainty and temporal granularity. In this sense, important operational conditions due to VRE intermittency, unit-commitment constraints, and flexible investment alternatives (e.g., storage) are often not captured in the literature. Consequently, this may result in inefficient portfolio of investments that are not suitable for different realisations of the future.

ii. Multi-level Scheme

This methodology is based on formulating integrated planning as a multi-level optimisation problem, where the upper-level refers to transmission system planning, which is subject to technical constraints and the lower-level problem usually representing distribution systems planning. Such approach is typical solved by leveraging KKT conditions and strong duality theorem to reformulate the lower-level problem, enabling the upper-level to consider the follower's optimal response within a single-level optimisation problem. In this sense, the different interests from agents involved in decision-making can be accounted for.

Similarly to centralised approaches, benefits in investment and operational costs for the whole system can be found. Authors in [32] found these conclusions while analysing the impact of distributed energy resources (DER) in decision-making over the transmission network, nevertheless, the impact of distribution networks constraints is neglected and thus, benefits may be inaccurate. This is analysed in [33], [34], but only accounting for the available flexibility of distribution networks, neglecting investments within them, not capturing trade-offs between large- and small-scale, and although [35] accounts for network reinforcements on both transmission and distribution systems, only a one-year planning horizon is modelled due to the complex formulation of the equivalent single-level problem.

In this sense, [36] uses a duality approach to reformulate a tri-level problem into a bi-level model (e.g., transmission and distribution planning) and to manage the complexity of this equivalent model, multi-parametric programming is applied to DSO planning problems to produce a set of single-level problems that are easier to solve than the initial bi-level formulation. However, this is still challenging since to find the optimal solution, all single-level problems must be solved, which would be difficult for problems with extended planning horizons and more technologies as investment options.

In this context, limitations remain for this method. Even though multiple interests are being captured, full knowledge of transmission and distribution networks is also assumed to reformulate the equivalent single-level problem, as otherwise KKT conditions and duality theorem cannot be utilised and thus, making its real-world applicability difficult. Thus, it would require that the system planner entity has jurisdiction over the whole system, same as the centralised approach.

iii. Iterative Scheme

The aim of this methodology is to consider communication variables (e.g., target and response) between TSOs and DSOs planning problems, and solve them iteratively until a stopping criterion is met. In this vein, this methodology removes the need for having full knowledge over the whole system by communicating both problems with reduced information [37].

A common approach is coordinating decision-making between TSO and DSO through the purchase and selling costs at the interface [38]. Recent studies have explored this by analysing the impact on investment decisions when including DER [39], and transmission cost allocation [40], [41], concluding potential benefits in terms of cost reduction, resource allocation, and computational efficiency. However, these studies focus on short-term planning horizons and overlook the long-term implications of investment decisions.

This aspect has been covered by authors in [42] and [43] where a 10-year planning horizon is assumed, however the complexity of the ITDEP formulations limits the ability to account for flexible investment options, such as storage and demand-side response. In this context, [44] addresses these limitations by introducing flexible investment options within distribution systems in the form of energy production and conversion technologies such as DGs, combined heat and power units, boilers, and heating and cooling pipelines. However, time blocks to represent the operation are assumed to keep tractability of the problem and thus, intermittency of VRE and DER, and the potential needs and value of flexible investment options (at both levels) are not properly captured.

Finally, even though data exchange between system operators is reduced and the solving methodology, both planning problems must be solved simultaneously to communicate key variables and meet any convergence criteria, which may be hard to achieve in real-world applications. Nevertheless, since planning problems can be managed individually, it could fit planning frameworks where transmission and distribution planners have clearly defined and independent roles, as is the case in Australia.

iv. Heuristic Decoupled

This is an emerging approach in which planning problems are also communicated with a reduced set of variables and/or constraints but differs from the previous approach in that the problems can be solved in a decentralised order rather than iteratively coordinated, decoupling the decision-making process by agents. In this context, it could improve scalability and enhance privacy as the need for having full knowledge of networks and simultaneous planning are avoided, solving more manageable planning problems.

A clear example is presented in [45], where a top-down multi-stage approach (e.g., from transmission to distribution) based on heuristic methods is employed, considering network and storage as investment options across all levels. Results show potential cost-reductions from storage expansion and curtailment management at the distribution level, contributing to the overall system's operation. However, a case study on the German power system revealed only marginal cost reductions, suggesting that there might be limitations in the broader applicability of the observed benefits or potential issues with the specific solving method.

Furthermore, [46] proposes an ITDEP by decoupling decision-making problems, representing ADNs with a surrogate single-bus model based on a generator, load, and storage. In this sense, the TEP is solved considering this representation and once solved, the power exchanges between TSO and DSOs are fixed as parameters within the detailed distribution network planning. In this sense, it has the potential for improving the solving performance of integrated planning when compared to previous approaches. Nevertheless, the work does not consider ADNs as investment options within the TEP, hence it does not capture trade-offs between large- and small-scale assets. In addition, the accuracy of surrogate model needs to be assessed carefully to truly represent the capabilities of distribution systems.

Under the same approach, authors in [47] analyse a coordinated planning problem for the Italian power system that considers synthetic networks for distribution systems. However, this work focuses on how demand flexibility and/or storage can compete against conventional network reinforcements for selected congestion zones rather than a detailed analysis of the impact of ADNs in a coordinated planning process. Moreover, authors identified that a fully integrated problem with this approach is extremely heavy from a computational point of view and thus, further simplifications might be needed.

On reflection, this approach has merit for integrated planning because of its decentralised solving methodology and reduced data exchange between agents, opening the possibility to represent ADNs as investment options within a transmission planning context. Moreover, this approach would allow to exploit the know-how capabilities of system operators, and thus it would support decentralised decision-making through information exchange, making it suitable for real world frameworks were transmission and distribution are managed independently such as the case in Australia.

v. Summary

To complement this overview, Table 2-1 contains the details associated with all the papers from the literature associated to ITDEP, highlighting scope and objectives, network considerations, investments options across all levels, planning horizon, operational granularity, optimisation approach and if there is application into a real-world problem.

		Network		Coordination Methodology	Investments		Planning Horizon	Operation Granularity	Optimisation Approach			Real World Application
Reference	Scope & Objectives	Trans.	Dist.		Trans.	Dist.			Determ.	Stochastic	Robust	
[26]	Compare coordinated and uncoordinated approaches	X	X	Centralised	Network	Network	One Year	Blocks	MINLP			-
[27]	Compare coordinated and uncoordinated approaches	X	X	Centralised	Network - BESS	Network - BESS	Multi-year	Blocks	MILP			-
[28]	Analyse the impact of DG and benefits of integrated planning	X	X	Centralised	Network - Generation	Network - DG	One Year	Hourly		MILP		-
[29]	Stochastic planning framework for network development, ensuring a reliable and secure energy supply	X	X	Centralised	Network	Network - ANM - DG	Multi-year	Blocks		MINLP		-
[30]	Multi-stage bi-level stochastic model to jointly plan transmission systems and merchant DER	X		Multi-Level	Network - DER	-	Multi-year	Blocks	MINLP	MINLP		-
[31]	Cost-based TSO-DSO coordination planning model to quantify the value of local flexibility services	X	X	Multi-Level	Network	-	One Year	Hourly	MIP			-
[32]	Leverage existing flexibility provided by ADNs into the transmission planning process	X	X	Multi-Level	Network	-	One Year	Hourly	MILP			-
[33]	Develop a planning framework that integrates the operational flexibility of ADN into TEP	X	X	Multi-Level	Network	Network	One Year	Hourly	MILP			-
[34]	Hierarchichal framework for ITDEP that leverages MPP to manage computational burden	X	X	Multi-Level	Network	Network - DG	One Year	Blocks	MPP MILP			-
[35]	Aims to achieve a more efficient and resilient power system by considering flexibility of ADNs	X	X	Iterative	Network	-	One Year	Blocks	MINLP			-
[36]	It combines robust and stochastic optimisation to improve overall system reliability and efficiency	X	X	Iterative	Network	Network	One Year	Hourly	MINLP		MILP	-
[37]	determine the planning scheme and scenario based generation schedule for ITDEP with DGs	X	X	Iterative	Network	Network	One Year	Blocks	MINLP			-
[38]	Evaluates the impact of transmission cost allocation when coplanning transmission networks and DER	X		Iterative	Network - DER	-	One Year	Hourly		MILP		-
[39]	Develops an ITDEP that efficiently allocates transmission cost	X	X	Iterative	Network	Network	One Year	Hourly	MINLP			-
[40]	Aims to create a comprehensive ITDEP strategy that optimises both infrastructure and market interactions	X	X	Iterative	Network - Generation	Network - DG	Multi-year	Blocks		MILP		-
[41]	Hybrid robust and stochastic ITDEP to determine a robust portfolio in a coordinated manner	X	X	Iterative	Network - Generation	Network - DG	Multi-year	Blocks		MILP	MILP	-
[42]	Multiple energy vectors are included in ADNs, comparing a decision-making problem with and without DSR	X	X	Iterative	Network	Network - DG - Heating - Cooling	Multi-year	Blocks	MILP			-
[43]	Present an open source software that is able to co-optimise grid and storage in a top-down approach	X	X	Decoupled	Network - BESS	Network - BESS	One Year	Blocks	NLP			German PS
[44]	Introduces a Julia/JuMP-based open- source tool for holistic planning of transmission and distribution grids	X	X	Decoupled	Network - BESS	Network - BESS - Demand Flexibility	One Year	Hourly		MILP		-
[45]	Presents the optimization results for Italian case study of the FlexPlan project	x	x	Decoupled	Network - BESS	Network - BESS - Demand Flexibility	One Year	Hourly		MILP		Italian PS

Table 2-1: Summary of literature review associated to ITDEP

3. Methodology for whole-system planning

Integrated planning frameworks could bring potential benefits regarding investment and operational costs, as well as improved resource allocation when compared to independent planning approaches. In this vein, system planners and regulatory entities around the world have identified the need for new methodologies to improve coordination and better address the challenges of future power systems.

As such, aspects that are often assumed in the literature, particularly full knowledge over transmission and distribution networks needs to be avoided, because the size of optimisation formulations increases (e.g., more variables and constraints), not allowing for a tractable problem nor an efficient coordination between real-world system operators that typically have independent planning roles. Consequently, the implementation of ITDEP in real-world scenarios would be difficult to achieve. Therefore, to fill this gap and truly unlock the benefits that ITDEP could bring, developing a methodology that efficiently coordinates system operators is the focus of this project.

In this sense, this work developed ***a bottom-up methodology to represent the planning of active distribution systems management within transmission planning frameworks***. Thus, the aim is to establish clear methodological steps on how DNSPs can produce information, in the form of a ***parametric representation of the investments needed within distribution networks that unlock the adoption and coordination of multiple levels of DER,*** and communicate that to system planners such as AEMO in the australian case, to include in their national planning frameworks.

This methodology is based on an investment and operational framework to determine an equivalent representation of active distribution system management's planning, from any reference node (e.g., low, medium or high voltage). Then, this representation is embeded into a transmission planning problem, where whole-system costs are minimised considering distirbution systems as investment options. These frameworks are going to be explained in depth in the following sections.

a. Investment framework

As depicted in Figure 3-1, we developed an approach based on an investment problem that minimises the investment and operational costs to support DER adoption over a planning horizon, subject to investment and operational constraints at any level of distribution systems.

Thus, by increasing the DER adoption in the network in an iterative fashion, the optimal portfolio of investments and its corresponding annualised costs (annuity of investments) are found. These are associated to infrastructure, that is distributed storage, network reinforcement, active network management, but could also include the annuity associated to the integration of DER if these assets were considered as investment options within an investment coupled whole-system planning framework. In turn, this iterative process allows to produce a **parametric investment cost function**, which represents the investments needed to unlock these resources.

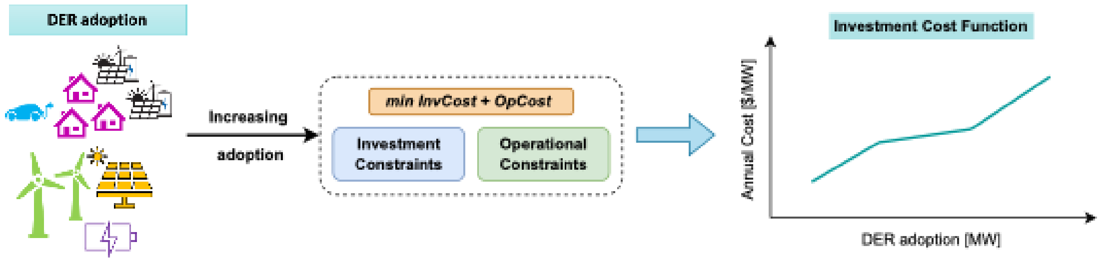


Figure 3-1: Investment cost functions for ADNs

For this framework, the optimisation formulation proposed is deterministic, meaning that it does not account for uncertainties associated to expected DER, although this could be covered by analysing multiple scenarios that could cover uncertain parameters. Nevertheless, the aim of this work is both, showing methodological steps for the integration of transmission and distribution planning, and assessing trade-offs with large-scale resource to understand if additional resources within distribution systems make sense or not, hence, a deterministic approach fits in well for these purposes.

In addition, it is possible to include the cost associated to infrastructure needed to coordinate demand-side resources or CER within the parametric cost function, meaning that coordination of CER (e.g., storage from EVs, batteries, heating/cooling loads, hot water, etc.) could be quantified as a decision of the model to solve local issues within distribution systems, and even as part of the analysed scenarios.

The cost-benefit analysis made in the EDGE project considers three different alternatives for coordination[2], *point-to-point, centralised hub, and decentralised hub*, which seek to register the connection of CER to share information [48]. Out of these solutions, the cheapest alternative is the ***decentralised hub*** where CER owners integrate with a common industry hub, exchanging information between multiple stakeholders. Therefore, this is the solution assumed in this project and represents a *total capital cost of around 2,000 $/MW* [3], which accounts for the decentralised hub infrastructure needed for the expected CER adoption (capacity in MW) according to the projections from the ISP 2022, as the study is based on these results from AEMO.

Finally, any DNSP can produce this information by employing their own tools and projections to plan their networks, and serves as a novel methodology to understand the best way to integrate distributed resources, i.e., what is the optimal schedule and the investments needed, where non-network solutions such as distributed batteries and active network management could be accounted for, to support the integration of these resources. Then, DNSPs can communicate these future investment paths (e.g., cost of distribtuion network augmentation that unlocks DER capacity) to the system planner such as

[2] **Point-to-point** – closest to the current arrangement in the market, where integration occurs between each participant in the facilitation of DER use cases and services. **Centralised data hub** – each participant only needs to integrate with a common industry data hub once, with data exchanged via a central broker (assumed to be AEMO in Project EDGE). **Decentralised data hub** – each participant only needs to integrate with a common industry data hub once, with data exchanged between participants in a way that does not rely on a single central broker.

[3] The solution has a total cost of M$ 105 for a 20-year period horizon and a discount rate of 4.43%. Thus, using the expected adoption of DER from the ISP, and a fixed investment cost for the whole period, it is possible to find the cost proposed in this report.

AEMO, enhancing the coordination over decision-making with a whole-system perspective. Furthermore, the parametric approach could be employed not only referring to DER capacity, but also for CER coordination, that is, the amount of consumer-owned resources that can be coordinated to alleviate network constraints and provide services upstream.

b. Operational framework

With the previous framework it is possible to value the upgrades needed within distribution networks to support multiple levels of DER, output that can be produced and communicated by DNSPs through their planning frameworks, allowing system planners to take more informed decisions regarding where and what technologies are cost-effective to develop power systems. Nevertheless, from a whole-system modelling point of view, integrating such cost function does not provide direct information on the operational flexibility that can be leveraged from DER, unless the whole distribution network and DER are modelled in detail (all variables and constraints). This would not differ from the approaches presented in the literature, hindering the real-world applicability of an integrated planning framework.

Therefore, to achieve a scalable whole-system planning framework it is crucial to understand how and what is the best method to represent the operational capabilities of distribution systems (within thermal and voltage limitations) that are unlocked by additional DER and investments to support them. In this context, we developed an operational framework that employs the concept of ***nodal operating envelopes*** **(NOE)** to characterise the flexibility limits of distribution systems, that is, maximum exports and imports for which the system can securely operate under network constraints [49], so that distributed resources can be aggregated and efficiently managed from a whole-system perspective.

This information can be produced for each level of DER adoption (and its temporal availability) within the parametric investment cost function and represents a suitable methodology that could be used by DNSPs to inform their network limitations and aggregated resources at different voltage levels, all the way up to the point of connection with the transmission system. Thus, as depicted in Figure 3-2, this methodology follows an iterative process where the base operation of the distribution system for each level of the investment cost function is identified, which allows for analysing the upward and downward flexible capabilities based on DER adoption and investments to support these resources.

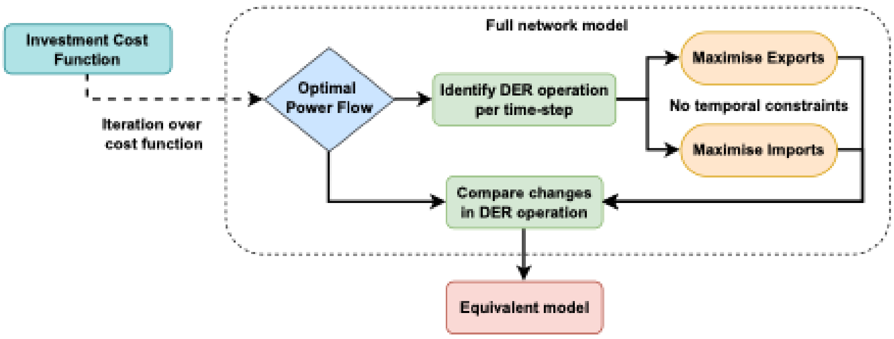


Figure 3-2: Operational framework to build equivalent model for ADNs

More in detail, this approach consists of *an optimal power flow where the objective is to maximise self-consumption with network and temporal constraints given a level of DER adoption*. From this operation, the maximum exports (i.e., minimisation of consumption from transmission system) and imports (i.e., maximisation of consumption from transmission system), are identified for each time-step. This allows to find what and the degree to which flexible assets can change their operation from the base case to support exports and imports. In this context, as DER adoption increases, as well as the investments to support this adoption, the nodal operating envelope will increase in size, meaning that more flexibility within distribution systems is available to the upstream network.

Then, distribution system's operational flexibility for each investment path (e.g., parametric cost function) can be characterised with an equivalent model consisting of a generator (renewables, curtailment, and non-renewables), flexible load (inflexible and flexible loads associated to demand response schemes), and storage component, which can be disaggregated to represent the different technologies such as batteries, EVs, thermal storage. These are determined by comparing how flexible assets can change their operational states towards exports and imports compared to the base operation, capturing the power limitations of each component while satisfying network constraints and thus, active distribution systems management can be modelled through the time-varying limits of these components within any transmission planning framework.

This is illustrated in Figure 3-3 by a dynamic representation of the active power associated to the operating envelope of a given distribution network, where the base operation, maximum imports and exports allow for capturing the time-varying parameters for the equivalent model are determined by analysing the flexibility from DER upwards (green arrows) and downwards (orange arrows).

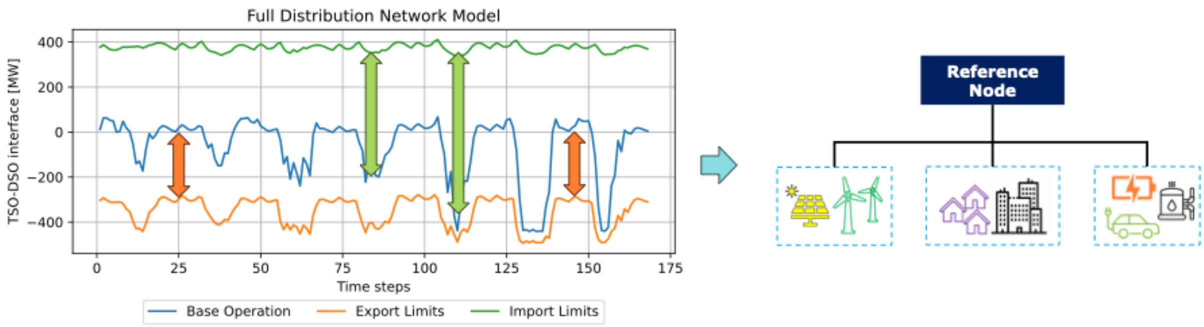


Figure 3-3: Characterisation of equivalent model according to dynamic active power operating envelope

Therefore, DNSPs could use these principles to produce information about the network limitations within their future investment paths with their own tools (e.g., power flows, operating envelopes, hosting capacity), and how some investment solutions, particularly active network management, can increase these flexible limits while reducing costs, unlocking DER upstream. This would clearly inform system planners like AEMO how much DER capacity can be leveraged from the transmission system when integrating distribution systems investment paths as options for decision-making under a whole system planning framework.

c. Integrated planning

This section describes the integrated expansion planning model that was developed for this project, emphasising the details behind the inclusion of the parametric planning of active distribution systems (i.e., investment cost and operational capabilities) as "flexible investment option" or as possible "future development paths" as seen in Figure 3-4. In this context, this whole-system formulation integrates the planning of active distribution system's management within any transission planning framework, allowing for deciding on the optimal participation from the demand side resources, DER, and the corresponding distribution network enhancement alternatives, capturing trade-offs between large- and small-scale developments from a whole-system planning perspective. Thus, the approach is based on DNSPs producing information regarding investments and operational capabilities within their networks, which is then communicated to power system planners, such as AEMO, improving the coordination of the decision-making process.

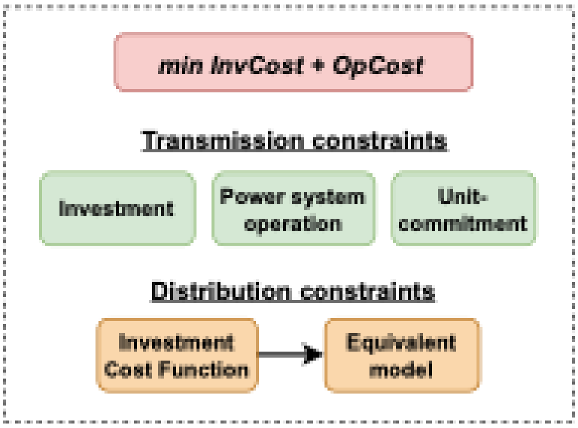


Figure 3-4: Distributed framework for investment coupled whole system planning

Moreover, whole-system planning is based on the minimisation of investment and operational costs for a planning horizon for both, transmission, and distribution systems. The system operational component of the total costs includes operational costs of all generation units and distribution systems, including demand-response bands (based on the ISP 2024) and the cost of not supplied to the customers at any given period, which in the context of this study is valued at the current market price cap for the NEM[4]. Therefore, given this formulation, the operational capabilities of distribution systems are managed in a centralised manner by the system planner entity, e.g., AEMO, but based on information produced by DNSPs with their own tools in a decentralised fashion.

Furthermore, the model imposes a set of constraints for investment and operational decisions, which include:

[4] 2024-25 market price cap. Available at: https://www.aemc.gov.au/news-centre/media-releases/2024-25-market-price-cap-now-available

- Transmission investment constraints: these include the so-called non-anticipativity constraints, which guarantee that an investment made at a certain node in the scenario tree will be present in the subsequent nodes connected to said node. These constraints also include the potential rules of investment across the portfolio of options, for instance, investment options that are mutually exclusive, investment options that must follow another investment option, or investment options that must be built simultaneously.
- Distribution investment constraints: these guarantee that only one future path can be optimally selected for a given distribution system representation, which could be one per sub-region within the ISP.
- Power system constraints: these correspond to all the constraints associated to power system operation, including energy balances, reserve provision, power flow, transmission limits, etc.
- Unit-commitment constraints: the operation of conventional units in the system is bound by their technical characteristics, for instance, ramping limits, minimum stable generation, start-up times, etc.
- Distribution operational capabilities: these are associated with managing all the components of the equivalent model proposed for this project. That is, renewable generation curtailment, storage operation including state-of-charge constraint, demand response capabilities, and the coupling with the transmission system.

d. Real-world applicability

This work developed a methodology based on principles that would allow its applicability to the real-world under current regulatory frameworks and roles from system operators. Thus, by producing information from a ***bottom-up approach*** regarding parametric investments and operational capabilities (aggregating resources) that can be communicated at different levels and between different stakeholders within power systems.

In this context, DNSPs, using their frameworks, tools, and know-how capabilities, can produce this information for multiple levels of DER adoption based on scenarios, projections, CER coordination, etc., across all levels of distribution network, going from MV-LV network up to HV or subtransmission networks, and communicate this to AEMO, who could make whole system investment decisions that coordinate transmission and distribution as depicted in Figure 3-5. Moreover, DNSPs could compare cases that consider only network reinforcements, and others that account for non-network solutions such as additional DER, active network management, etc., aligned with the methodology proposed in work package 2.9 of this project.

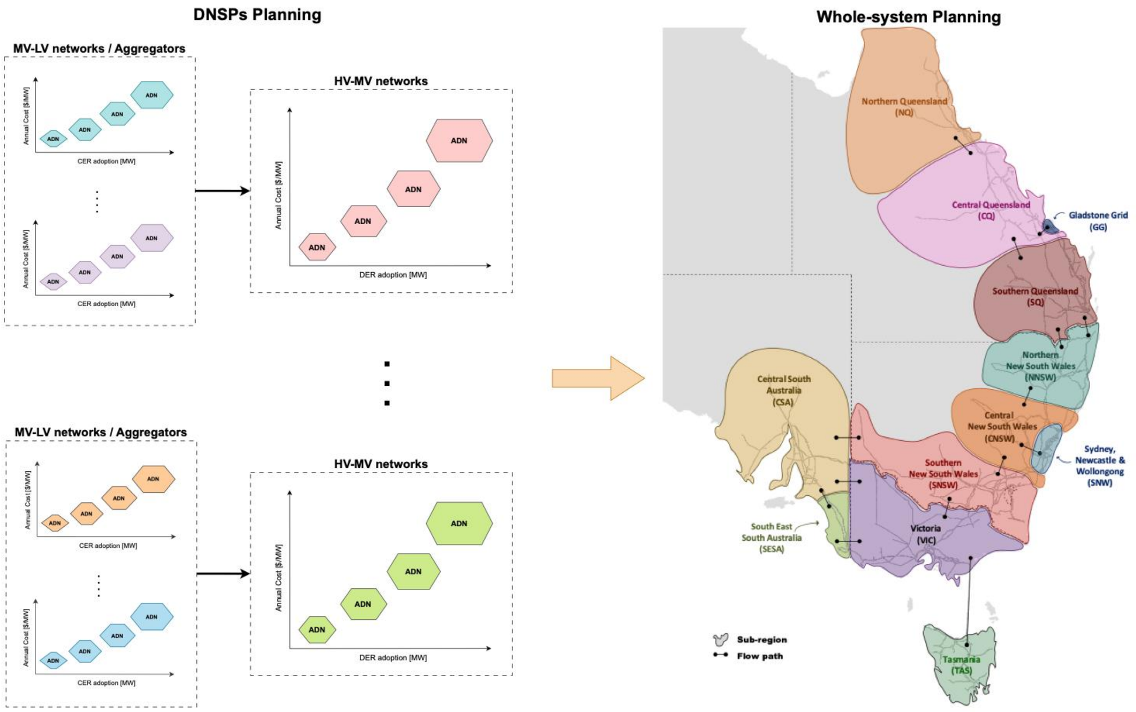


Figure 3-5: Whole system planning with communication through proposed planning methodology

Furthermore, AEMO has begun to develop a methodology to integrate distribution network capabilities and opportunities for CER and DER within the ISP [50]. ***This methodology is well aligned with the one proposed in this work package as it is based on a decentralised approach*** where to account for distribution network constraints, AEMO will consider two main limitations: the operational constraints of CER due to distribution network limitations and constraints on the uptake of CER and additional DER. These constraints ensure that the distribution network, and possible augmentations, can support CER and more broadly, DER, integration without exceeding its capacity.

In this context, it could be interpreted that the first constraint would represent the limitations within MV-LV networks, where most CER is connected, while the latter would represent HV or subtransmission, ***following a bottom-up assessment***. Moreover, although there are similarities in terms of principles, the proposed methodology allows for assessing the impact of active network management, non-networks solutions within distribution networks, and the impact of CER coordination, which could reduce investments in traditional distribution network reinforcements, while also proposing a novel method for aggregating distributed resources while accounting for network constraints. In addition, it allows for decision-making over additional DER, considering distribution networks as investment opportunities rather than infrastructure to supports expected adoption of CER.

Finally, to model these constraints effectively, AEMO will collaborate with DNSPs using two approaches. The **data asset approach** calculates the volume of CER output being enabled for each distribution data asset, using DNSP-provided network limits and disaggregated AEMO forecasts for

CER uptake and consumer load, before being aggregated back up to the sub-regional reference node. Under the **detailed modelling approach**, DNSPs would perform their own analyses using AEMO's forecasts, enabling more accurate estimations of CER integration and network constraint.

For both approaches, DNSPs will provide indicative cost curves for distribution augmentation (costs and associated augmentation capacities to enable higher levels of CER operation), that the capacity outlook model uses to choose to build to allow further output of CER to reduce curtailment. This means that AEMO is proposing a communication pattern that is aligned with the one proposed in this work package, closely collaborating with DNSPs to determine cost functions to support CER.

4. Input data

The following section describes all the input data and assumptions used in this project to deliver clear insights about the value that can be extracted from a whole-system decision-making framework, and how information can be produced by DNSPs with a bottom-up approach.

It must be noted that the aim of this work package is to deliver a clear methodology to produce this information, and the flexibility that it provides in terms of what solutions can be considered within distribution networks to make the adoption of DER more cost effective. Therefore, since case studies are performed on subtransmission networks, also assuming that MV-LV networks are unconstrained, any quantification of benefits throughout this report is illustrative rather than representative.

a. Distribution network models

This work package uses the network models developed in WP 1.4 Whole of Distribution Network Architecture[5], with a particular focus on 66 kV subtransmission networks as there is a gap that has been identified by DNSPs regarding planning these networks due to DER connections enquiries, and that this aspect is not currently considered by the ISP.

Five 66 kV subtransmission network models, property of AusNet[6], were available as a result from 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) as depicted in the following figures.

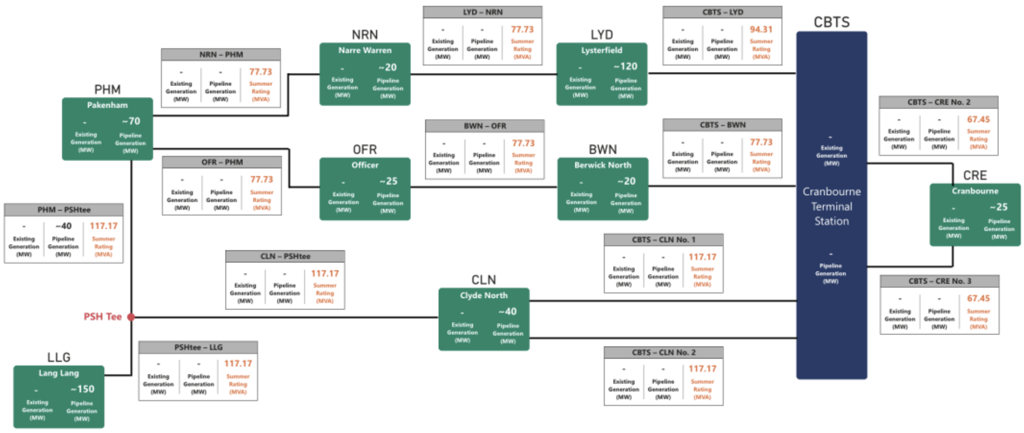


Figure 4-1: Cranbourne Terminal Station

[5] WP 1.4 Whole of Distribution Network Architecture. Final report. December 2024.
[6] https://app.powerbi.com/view?r=eyJrIjoiNGI1YmUyZjctNTA1ZS00ZTJjLTg5ZTgtYjhkMWMwNWYyN2FhIiwidCI6ImEzOTRlNDFjLWNmOGQtNDU4ZS1hYzFiLWRkYWUxYWExNTYyOSIsImMiOjEwfQ%3D%3D

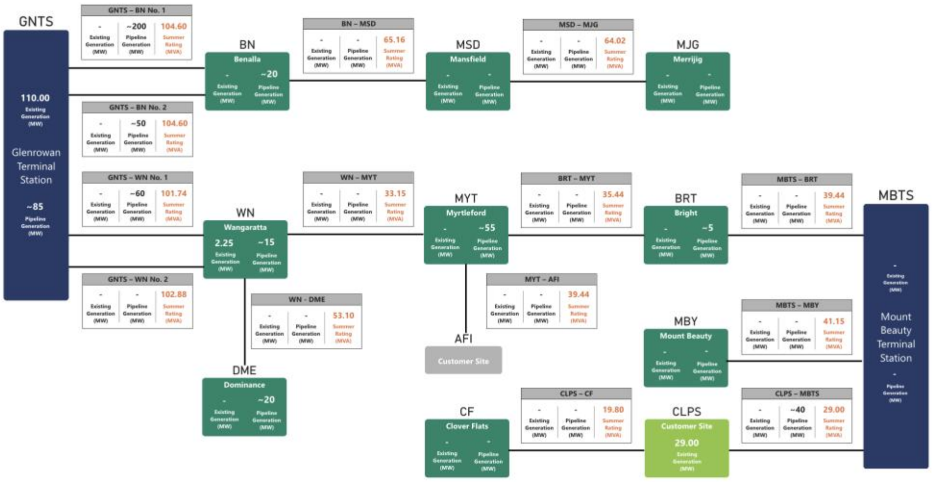


Figure 4-2: Glenrowan Terminal Station and Mount Beauty Terminal Station

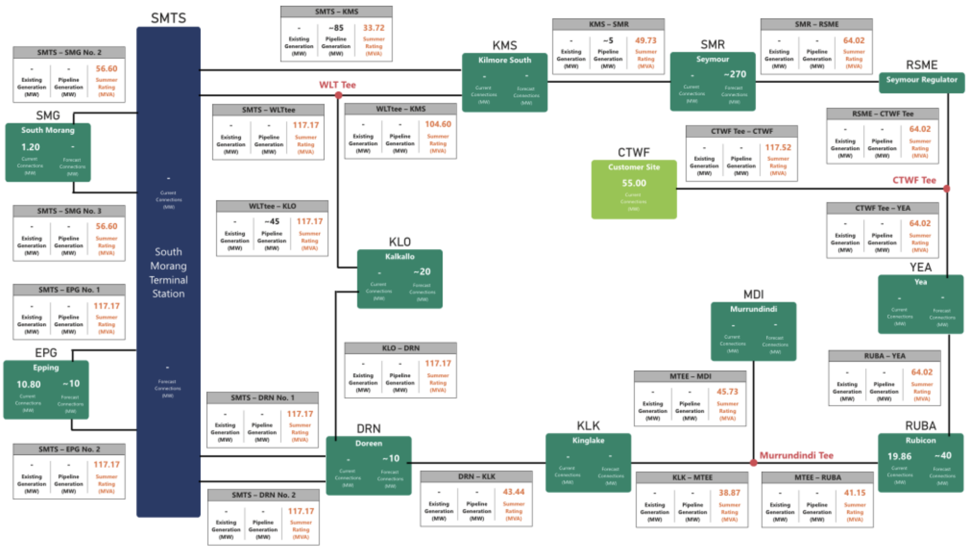


Figure 4-3: South Morang Terminal Station

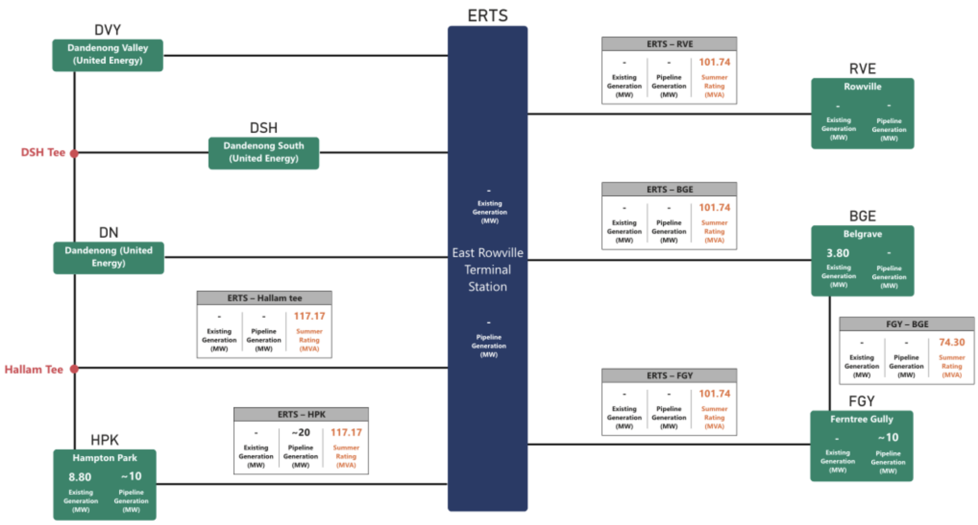


Figure 4-4: East Rowville Terminal Station

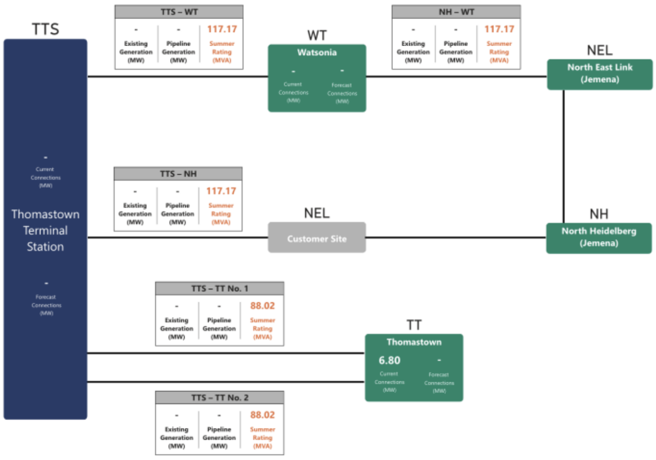


Figure 4-5: Thomastown Terminal Station

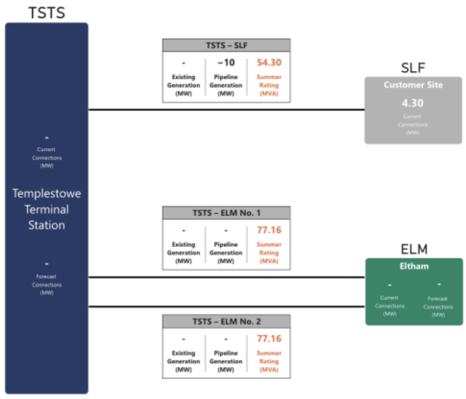


Figure 4-6: Templestowe Terminal Station

Each of these subtransmission networks are characterised with a rooftop PV capacity and a peak demand according to Table 4-1, where it is shown how much of Victoria's totals are represented by this set of networks, that is 19% for rooftop PV and 17% for peak demand. Moreover, 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 (all of these are results from WP 1.4), as presented in Table 4-2. It can be inferred that the networks used in this work mainly represent urban, and a share between short and long rural MV-LV networks.

Table 4-1: Rooftop PV capacity and peak demand, base year 2024

	Rooftop PV		Peak Demand	
ST Network	**Capacity [MW]**	**Ratio to Victoria [%]**	**Peak [MW]**	**Ratio to Victoria [%]**
CBTS	345.34	7%	471.30	4%
GNTS-MBTS	60.80	1%	119.48	1%
SMTS	206.33	4%	299.03	3%
ERTS	169.21	4%	475.90	4%
TTS	78.56	2%	251.00	2%
TSTS	26.96	1%	365.97	3%

Table 4-2: Zone substation composition for subtransmission networks

ST Network	Name	Name	Postcodes	Clients	Urban	Suburban	Short rural	Long rural
CBTS	CRE	Cranbourne	3977	23325	4	0	2	0
	LYD	Lysterfield	3156	7524	2	0	2	0
	BWN	Berwick North	3806	9009	3	0	1	0
	NRN	Narre Warren	3804, 3805	6338	4	0	1	0
	OFR	Officer	3809	22521	2	0	1	1
	CLN	Clyde North	3978	35625	4	0	4	0
	PHM	Pakenham	3810	16112	4	0	4	0
	LLG	Lang Lang	3984	7083	4	0	2	0
GNTS-MBTS	WN	Wangarrata	3677	18171	2	0	1	4
	BRT	Bright	3741	4448	0	0	3	0
	MYT	Myrtleford	3737	6107	0	0	3	1
	MJG	Merrijing	3723	1368	0	0	1	0
	MSD	Mansfield	3722	6826	0	0	0	3
	CF	Clover Flat	3315	725	0	0	2	0
	MBY	Mt Beauty	3699	2150	0	0	4	0
	BN	Benalla	3672	12462	1	0	1	3
SMTS	SMG	South Morang	3752	14086	7	0	0	0
	KLO	KalKallo	3064	13809	2	0	1	1
	SMR	Seymour	3660	11031	0	0	3	3
	RUBA	Rubicon A	3712	5058	0	0	2	1
	MDI	Murrindindi	3717	55	0	0	1	0
	KLK	Kinglake	3763	2498	0	0	3	0
	DRN	Doreen	3754	28745	2	0	5	1
	EPG	Epping	3076	28103	11	0	2	0
	KMS	Kilmore South	3764	5795	0	0	2	0
ERTS	DVY	Dandenong Valley - UE	4284	3805	11	0	1	0
	DSH	Dandenong South - UE	1707	3175	10	0	0	0
	BGE	Belgrave	12145	3160	1	0	5	0
	DN	Dandenong - UE	20264	3175	14	0	0	0
	FGY	Ferntree Gully	19678	3156	8	0	2	0
	HPK	Hampton Park	27495	3976	6	0	2	0
	RVE	Rowville	4240	3178	1	0	2	0
	UWY	Upwey	1079	3158	0	0	1	0
TTS	WT	Watsonia	3083, 3087, 3088	24943	10	0	0	0
	TT	Thomastown	3047, 3061, 3074	15043	8	0	0	0
TSTS	ELM	Eltham	3095, 3113, 3115	27454	2	0	2	0
	SLF	Sugarloaf	3234	N/A	0	0	1	0

It is worth mentioning that, even though this project seeks to analyse subtransmission networks, the proposed methodology can be applied to any distribution level and point of reference (e.g., MV or LV transformer) and thus, investment information can be produced at several reference points within distribution networks. In this sense, this methodology could help in determining the benefits that come from CER coordination for instance, at the MV-LV level, an aspect that has not been addressed within a real-world context, nor as a representative assessment. These networks are characterised by the information shown in Table 4-3, and can be visualised in Figure 4-7.

Table 4-3: MV-LV networks overview

Network Type	Number of Customers	Number of Buses	Number of Transformers	Network Length [km]	Maximum demand [MVA]
Urban	3181	6020	48	20	10.55
Suburban	5514	10902	71	33	13
Short Rural	724	2202	187	93	8.42
Long Rural	3942	9153	877	207	9

a) Urban

b) Suburban

c) Short rural

d) Long rural

Figure 4-7: MV-LV typical feeders

b. Expected DER adoption

To employ the proposed methodology, it is crucial to understand what parametrisation is suitable for each subtransmission network. Based on this, AusNet provided information regarding enquiries for DER connection within these networks as depicted in Table 4-4, for which is needed to plan the network. In this context, an increasing adoption of these resources could be employed as parametrisation, meaning that for each of these subtransmission networks a cost function can be produced.

Moreover, this parametrisation would work only when planning of the network for the next stage, i.e., 5 years, as after that period it can be assumed that these projects will either be connected or not, and thus, for analyses deep into the future and the ESP scenarios, it makes much more sense to use levels of DER/CER coordination as the parametric approach.

Table 4-4: DER connection enquiries

Subtransmission Loop	Generation Source	ZSS	Installed Export/Generation Capacity (MW)	Installed Import/Storage Capacity (MW)
CBTS	Battery	BWN	18.82	18.82
	Battery	CLN	20	20
	Battery	CLN	18.82	18.82
	Battery	NRN	18.82	18.82
	Battery	LYD	20	20
	Battery	LYD	100	100
	Battery	LLG	100	100
	Battery	OFR	4.99	4.99
	Biogas	PHM	40	-
	Biogas	PHM	65	-
	Hybrid (Solar + AC Coupled Battery)	LLG	40	10
ERTS	Biogas	HPK	20	-
	Biogas	HPK	10.5	-
GNTS-MBTS	Battery	MYT	55	55
	Hybrid (Other)	CLPS	4.99	4.99
	Hybrid (Solar + DC Coupled Battery)	BN	200	200
	Hybrid (Solar + DC Coupled Battery)	WN	60	60
	Hybrid (Solar + Hydrogen)	BN	50	50
	Hydrogen	CLPS	37.66	-
	Solar	WN	70	-
	Solar	DME	22	-
	Solar	GNTS	86	-
SMTS	Battery	RUBA	40	40
	Biogas	WLT	45	-
	Biogas	DRN	9	-
	Hybrid (Solar + DC Coupled Battery)	KMS	85	85
	Solar	KMS	4.99	-
	Solar	SMR	4.99	-
	Solar	SMR	50.6	-
	Solar	KLK	5	-
	Wind	SMR	200	-
TSTS	Solar	SLF	8.5	-

In addition, in terms of demand and CER projections (e.g., EVs, distributed BESS, rooftop PV, etc.), these are based on C4NET projections, and the outputs produced by WP 2.10. The expected adoption can be seen in Table 4-5 for the whole state of Victoria in 2040 and 2050.

Table 4-5: C4NET projections for 2040 and 2050

Parameter	2040	2050
Number EV	3,351,437	6,266,686
Number Household BESS	740,695	978,655
Dwellings	3,715,868	4,195,252
Household BESS [MW]	5,600	9,300
Rooftop Capacity [MW]	14,255	20,532

Finally, it is important to note that all these resources are assumed to be optimally coordinated, that is, they are used to reduce total investment costs in infrastructure when planning subtransmission networks. Particularly, CER coordination can be parametrised as the access to these resources will depend largely on the willingness of customers to participate in system services, but in the case of large-scale DER (connected at the subtransmission level) it is always assumed that can be optimally coordinated, meaning curtailment of energy, optimal storage usage, reactive compensation, etc.

c. Investment costs

Most of the costs used in this work are based on AEMO's inputs and assumptions from the ISP 2024 and public information associated to regulatory investment tests from DNSPs[7]. In particular, Table 4-6 shows investment costs for subtransmission network reinforcements for the areas of Morwell South and East, networks property of AusNet [51], [52]. Even though 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. This assumption was made as the two cheapest solutions only consider small cable replacements, but nothing around support infrastructure, which is important to capture. Moreover, 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 4-6: Investment costs for network reinforcements

Source	Alternative	New capacity (MVA)	Delta (MVA)	Upgrade length (km)	Total cost upgrade	$/MVA	$/MVA/km
Connection Enablement: Morwell South Area (AusNet)	ALLUMINIUM 19/3.25 - OPTION 1	**128**	49	59	$ 36,600,000	$ 746,939	**$ 12,660**
	ALLUMINIUM 19/4.75 - OPTION 2	**210**	131	59	$ 88,400,000	$ 674,809	**$ 11,437**
	ALLUMINIUM 37/3.75 - OPTION 3	**236**	157	59	$106,100,000	$ 675,796	**$ 11,454**
	ALLUMINIUM 37/3.75 - OPTION 4	**290**	211	59	$143,014,149	$ 678,757	**$ 11,504**
Connection Enablement: Morwell East Area (AusNet)	ALLUMINIUM 19/4.75 - OPTION 1	**183**	104	19	$ 4,410,000	$ 42,404	**$ 2,232**
	ALLUMINIUM 19/4.75 - OPTION 2	**202**	123	19	$ 7,050,000	$ 57,317	**$ 3,017**
	ALLUMINIUM 37/3.75 - OPTION 3	**236**	157	19	$ 34,890,000	$ 222,229	**$ 11,696**

In addition, the investment costs for technologies analysed in this work package are as presented in Table 4-7. These come directly from AEMO's inputs and assumptions [6] and are referred to large-scale investments (e.g., transmission level). Nevertheless, as the analyses conducted in this project are mainly on the subtransmission level and that many of the projects are large-scale DER, the same capital costs were assumed. For hybrid power plants, we simply added the costs of the generation source and one hour of storage as a conservative assumption, as there might be some costs savings that are not entirely clear such as DC connections, inverters, etc. Moreover, for solutions such as distributed BESS

[7] https://www.ausnetservices.com.au/projects-and-innovation/regulatory-investment-test
[8] Transmission Cost Database. AEMO. 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

for network expansion, a scaling factor of 1.25 was assumed due to economies of scale, and it is based on a review on small-scale batteries compared to large-scale transmission connected ones.

Table 4-7: Investment costs for technologies, Step Change scenario

Technology	2024-25	2030-31	2035-36	2040-41	2045-46	2050-51
Solar	1,523	1,145	987	735	668	627
Wind	1,523	1,145	987	735	668	627
Wind Offshore	5,654	4,654	4,400	4,264	4,114	4,011
BESS (1 hour)	943	666	589	542	506	474
BESS (2 Hours)	1,330	858	749	689	644	607
BESS (4 Hours)	2,130	1,253	1,074	984	928	885

5. Case studies

The following case studies aim at illustrating the proposed methodology and principles for its implementation, outlining the necessary information and communication pathways needed for real-world implementation. Achieving a fully integrated investment-coupled whole-system planning framework would require accurate representation and assessments of distribution system planning and thus, benefits quantified in this section should not be regarded as being fully representative but rather as a foundational step.

a. Key aspects of distribution system planning

i. Proactive planning

The first insight that can be obtained from this methodology is the importance of proactive distribution network planning when integrating CER and more broadly, DER, and how this approach could greatly benefit the adoption of DER when compared to large-scale investments from a whole-system perspective. This is aligned with the rule change requested by Energy Consumers Australia to the AEMC [53], calling for an integrated distribution system planning where DNSPs better utilise existing data, develop plans to collect more granular data, and enhance the scope and transparency of their network planning, publishing key data and methodologies, such as CER hosting capacity maps.

The aim is to support the National Electricity Objective by enabling smarter use of current infrastructure, improving distribution network planning and utilisation, enhancing transparency, and guiding more effective investment in CER. In this context, the methodology proposed in this work package could enable this rule change and serve as baseline for DNSPs to move towards this integrated distribution system planning, taking more efficient decisions at the distribution level that can be communicated towards national system planners and achieve whole system planning frameworks.

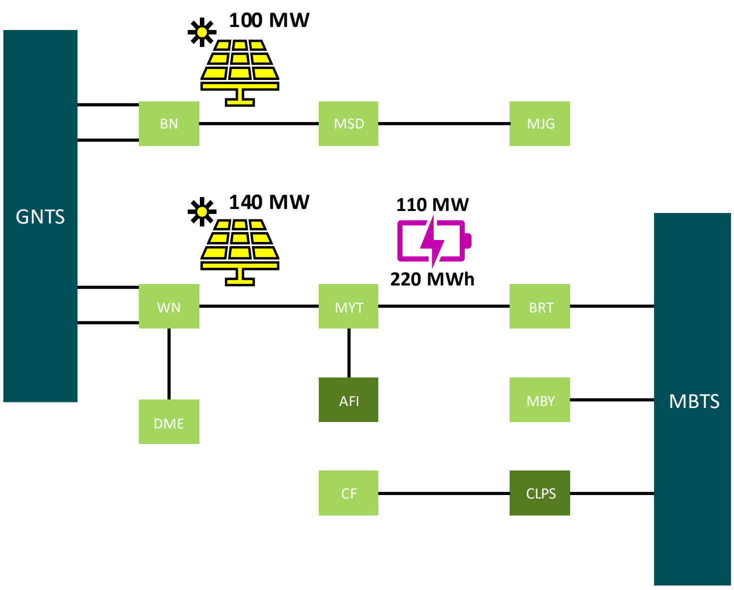


Figure 5-1: DER adoption in subtransmission network Glenrowan and Mount Beauty

To showcase this, a simple example with the Glenrowan and Mount Beauty terminal station (66 kV) was developed where there are three projects expected to connect, from which several connection schedules can be considered to plan the network. As depicted in Figure 5-1, these are two solar farms of *100 MW* at the zone substation Benalla (BN), and *140 MW* in zone substation Wangaratta (WN), and in addition a BESS of *110 MW and 220 MWh* at Myrtleford (MYT). It is worth mentioning that this analysis only includes the annual investment costs to enhance distribution infrastructure, that is, network reinforcements, reactive compensation, and distributed batteries.

Thus, by producing an investment cost function to support levels of DER (*considering only distribution network infrastructure*), it has been shown that proactively planning distribution networks jointly with expected DER can produce a huge difference in the infrastructure investments that need to be in place, as depicted in Figure 5-2. For instance, when the connection of both solar farms is prioritised, investments are needed to reinforce the network between GNTS, WN, BN, and MYT to allow for exports from the solar farms. Nevertheless, some of these investments are displaced once the BESS is connected, as this technology can help in managing both, consumption patterns and distributed generation. For this reason, if the connection of the BESS is prioritised, some infrastructure investment could be avoided or displaced, planning the network more efficiently.

In this sense, since all DER connection schedules converge to the same planning costs at the maximum capacity, one could ask, if the optimal solution is to connect the maximum DER capacity, what are the benefits of reduced investment costs for lower DER adoptions? The answer is the ***time-value of investments***, which means reducing investment costs now by proactively planning distribution networks, integrating DER in a more efficient way so that investments are made progressively (either deferred or replaced) over time, reducing the possibility of stranded assets and making a smoother transition into the maximum DER integration of 350 MW as in this example.

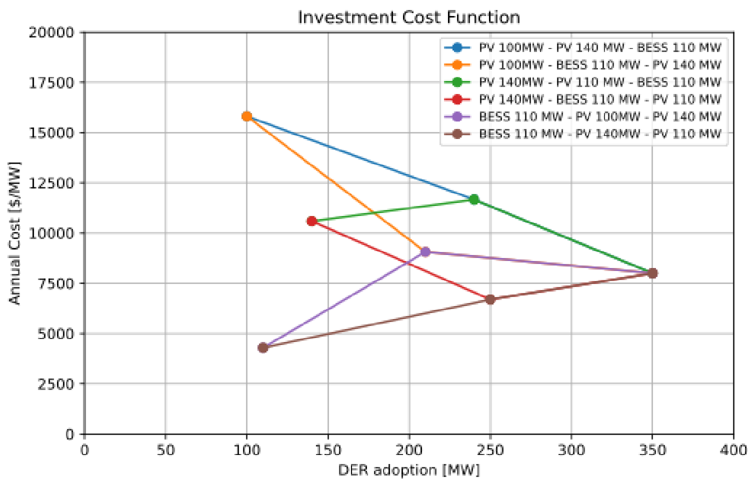


Figure 5-2: Investment cost function when proactively planning distribution systems

Therefore, proactive distribution system planning would allow for taking advantage of the synergies between different DER/CER technologies and their location, such as solar and BESS, which can help reduce total investment costs and make DER more cost-effective from a whole system perspective. Therefore, this methodology can enhance the understanding for DNSPs on the most economical way to integrate DER over time, reducing costs while enhancing network capacity more efficiently. In turn, DNSPs, through proactive planning, could provide insights on the best locations and technologies to develop DER, such as community batteries, EV charging stations, etc., enhancing benefits for customers while reducing costs.

ii. Active network management as an investment option

Other key options when planning distribution systems are active network management (ANM) and the coordination of CER. These would mean that DNSPs can make use of control schemes to operate the network, for instance, by curtailment of renewable generation, and coordinating resources to solve some of the local issues that could be faced such as voltage rise and drops or congestions, and in turn, such control schemes could displace traditional investment such as network reinforcements. To showcase this, the same example from Figure 5-1 is analysed using as reference the least-cost development path from Figure 5-2, which is associated to the solution of proactive distribution system planning when integrating the DER; that is, two solar farms of *100 MW* at the BN, and *140 MW* in WN, in addition to a BESS of *110 MW and 220 MWh* at MYT.

First, as shown in Figure 5-3, the impact of curtailment is analysed. As more curtailment is allowed, the investments needed are reduced, particularly when the solar units are connected. This scheme primarily impacts how much reactive compensation is needed to safely operate the network within the voltage limits, nevertheless, there is an opportunity cost associated to curtailing this energy.

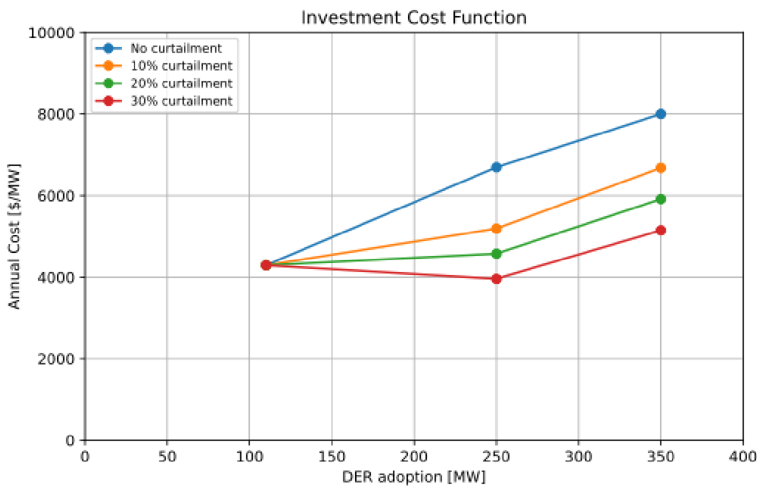


Figure 5-3: Impact of active network management in the form of curtailment

Currently, the cost used to value curtailment is the customer export curtailment value (CECV) [54], and although it is a good proxy for the purpose of planning the network, it must be noted that the optimal level of curtailment would be determined by a whole-system planning framework and thus, it might be cost-effective to either reduce or increase curtailment within distribution networks instead of the "optimal" level of curtailment that would result from distribution planning (using CECV), and this is something that will be worth exploring as it is the essence of a whole-system planning framework where trade-offs between transmission and distribution investments are captured.

Furthermore, coordinating existing DER, namely CER, will also play a role in accommodating these medium-scale DER. If these resources can be properly coordinated, they could unlock additional benefits when proactively planning distribution network and demonstrate how cost-effective additional distributed resources could be. Thus, over the optimal result from proactive planning presented in Figure 5-2, 75 MW of CER in the form of VPP[9] (as AEMO models CER coordination in the ISP), are assumed and spread in the GNTS-MBTS network according to the peak demand in each zone substation. The adoption of this storage is based on the projections of the step-change scenario from the ISP 2024 for the state of Vicotria, which can be accessed with the coordination cost of 2,000 $/MW. Based on this, we compute the investment cost function depicted in Figure 5-4.

Results show that there are reductions in total annual infrastructure costs, as well as an increase in the dispatchable capacity (CER added to the total DER capacity). Thus, coordinating CER could have a huge impact in reducing infrastructure costs and allocating additional resources within distribution networks. However, it must be noted that the effect of CER coordination within the MV-LV level is not included in this result, nor the willingness of customers to be coordinated although the cost to do so is included in the annual costs. Nevertheless, but if both these aspects are assessed properly, benefits in terms of investment costs and for customer could be increased even further.

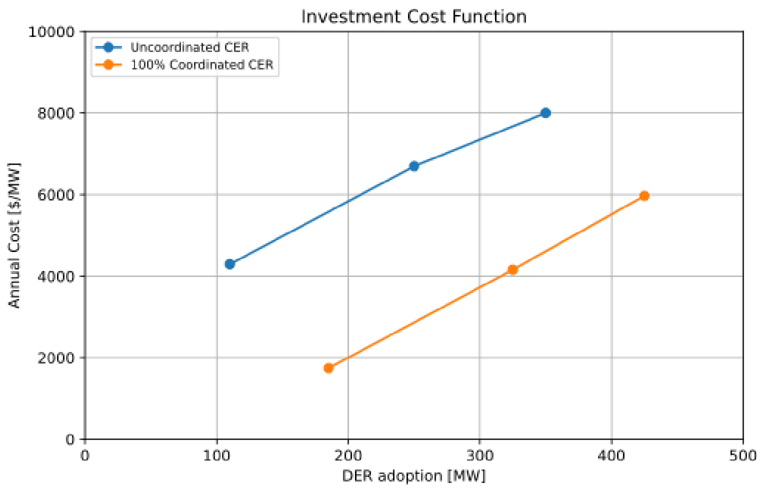


Figure 5-4: Impact of coordinating 75 MW of distributed batteries in the GNTS-MBTS network

[9] A VPP is modelled as a storage device with 2.2 hours of duration. This is based on AEMO's inputs and assumptions for the ISP.

Therefore, ANM could provide a suitable alternative for DNSPs to look at when planning their networks, and in turn, take a more active role in the operation of distribution system. Doing so could open the door for additional DER to connect, which could be more attractive from a whole-system perspective when compared to large-scale investments at the transmission level.

b. Additional DER adoption

To better understand the value of additional DER when compared against large-scale resources, this section explores the planning of subtransmission networks *CBTS*, *GNTS-MBTS*, and *SMTS* using as parametrisation the DER connection enquiries presented in Table 4-4. The reason behind analysing these networks is that they expect the most DER capacity to be connected and could serve as a suitable case study to analyse further the integration of the proposed methodology into transmission system planning frameworks, allowing for coordination during decision-making. ***Moreover, as reference, these networks are proactively planned, meaning that the integration of DER as parametric adoption is optimally allocated to reduce total infrastructure costs.***

Figure 5-5 shows the investment cost functions for these networks. These are built including the investment costs associated to each DER project as we aim to optimally compare them with large-scale resources, deciding if additional DER is cost-effective when developing future power systems. The increasing behaviour of the investment cost functions ($/MWh) for GNTS-MBTS and SMTS is due to the DER adoption mainly being distributed generation, while the decreasing behaviour for CBTS is explained because the expected resources are mainly BESS.

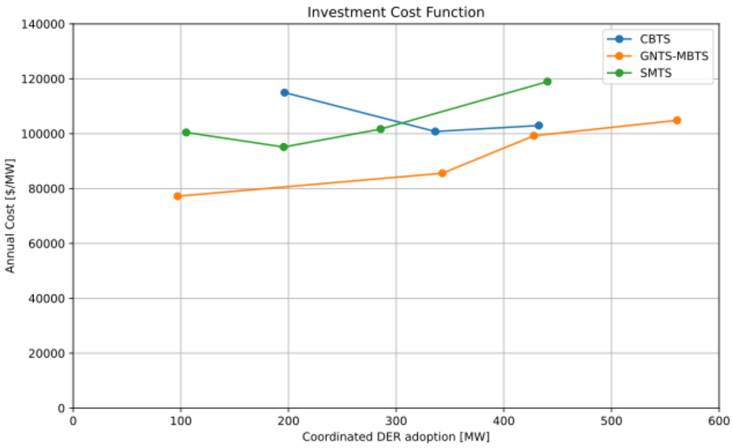


Figure 5-5: Investment cost function CBTS, GNTS-MBTS, SMTS

Moreover, from this information, the operational capabilities of each subtransmission network can be computed, finding their equivalent model for each DER adoption, as proposed in Section 3. Thus, the impact of investments and additional DER in the flexibility represented by the equivalent model will be illustrated as a ***dynamic representation of active power associated to the nodal operating envelope, in each time step, of the analysed distribution network***.

First, as depicted in Figure 5-6 and Figure 5-7, dynamic flexible limits of active power for GNTS-MBTS clearly increase with the adoption of large-scale DER, particularly due to the distributed generation and curtailment during daytime, and due to the storage from hybrid power plants throughout the day. Also, it can be concluded that the equivalent model approach represents these flexible limits with high accuracy, allowing for modelling distribution networks with a reduced set of variables and constraints.

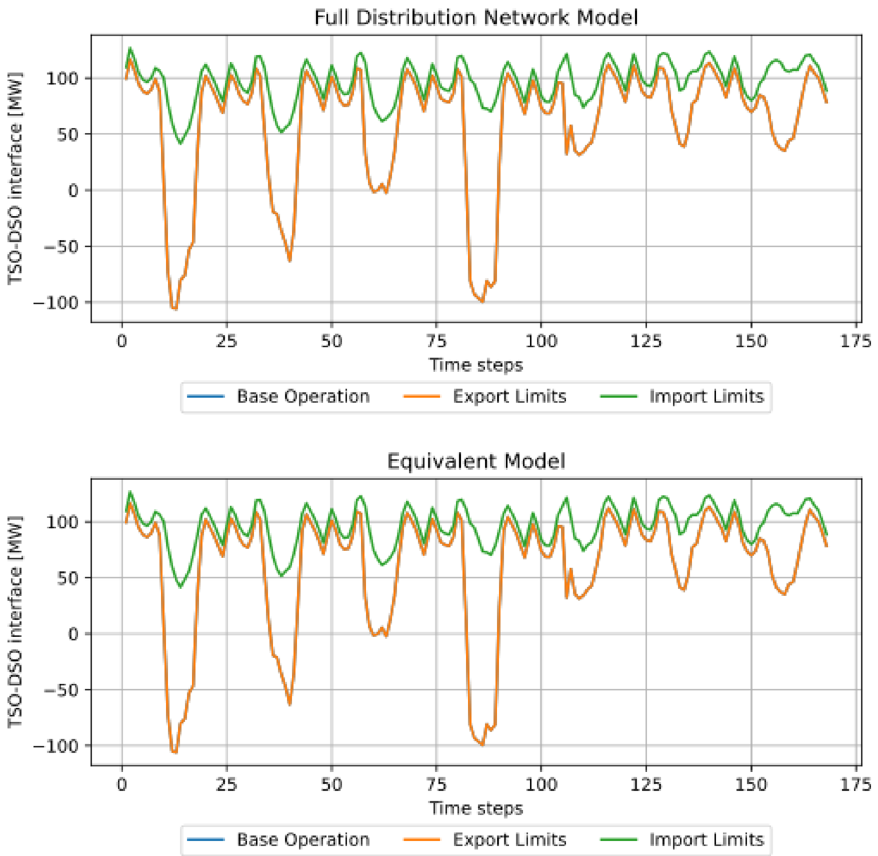
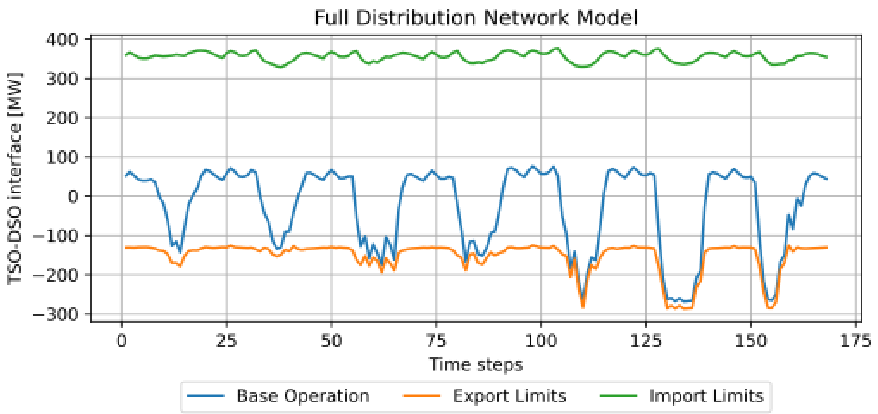


Figure 5-6: Operational limits for GNTS-MBTS, large-scale DER adoption 100 MW



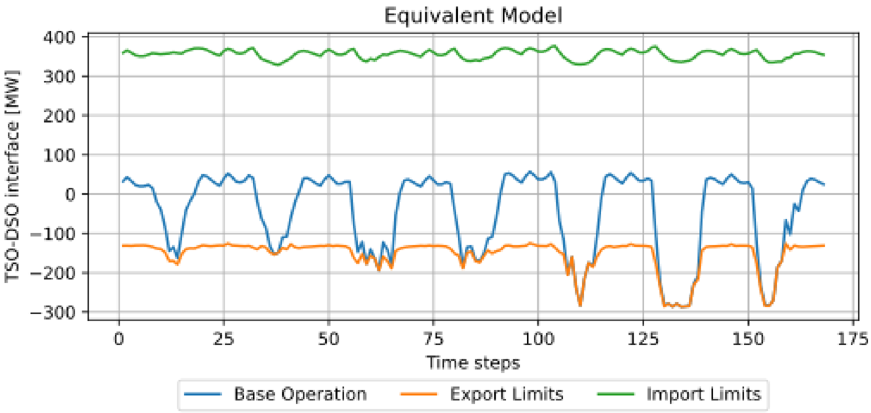


Figure 5-7: Operational limits for GNTS-MBTS, large-scale DER adoption 550 MW

In a similar fashion, the dynamic active power flexible limits of SMTS's equivalent model also increase with the adoption of large-scale DER as seen in Figure 5-8 and Figure 5-9. This network, as GNTS-MBTS, also expects the connection of distributed generation mainly, including distributed wind.

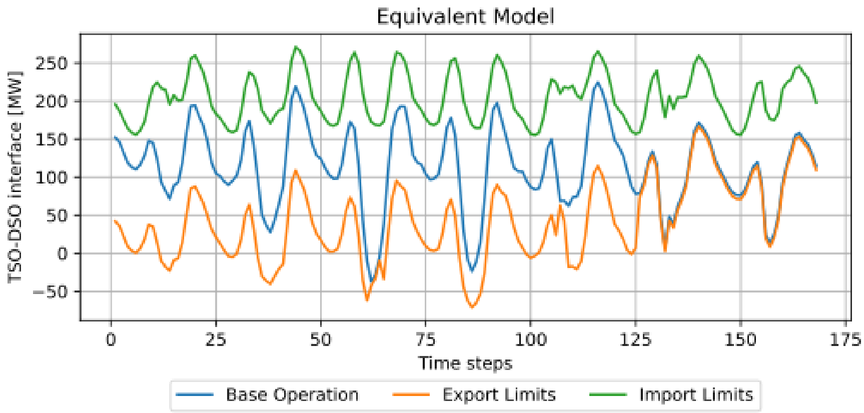


Figure 5-8: Operational limits for SMTS, large-scale DER adoption 100 MW

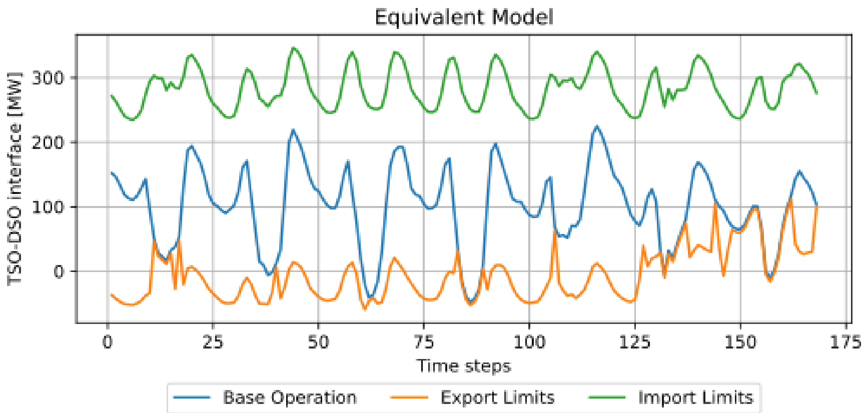


Figure 5-9: Operational limits for SMTS, large-scale DER adoption 300 MW

Finally, since the CBTS network mainly expects the integration of distributed BESS as the main technology within the parametrisation, the flexible limits do not increase significantly with the additional adoption. The reason behind this is that BESS allows for solving local issues such as congestions and reactive needs and even allows for reducing curtailment of distributed generation. Thus, there is no network reinforcements to support additional exports as was the case for GNTS-MBTS and SMTS. In this sense, even though there is no increase regarding power for imports and exports, there is a gain in terms of storage capacity.

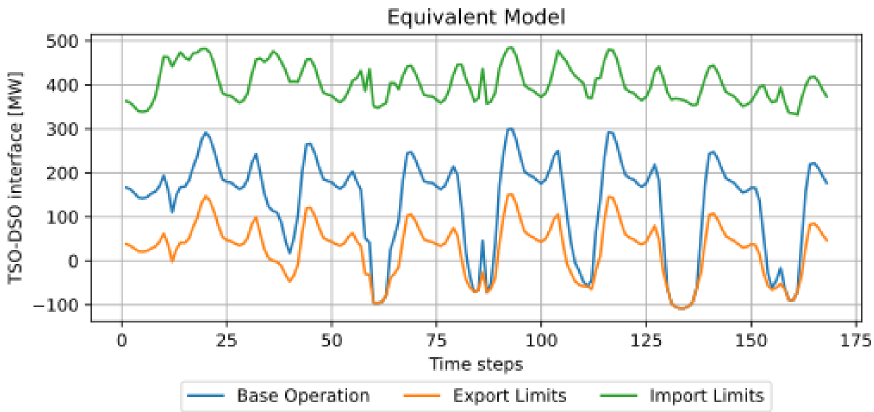


Figure 5-10: Operational limits for CBTS, large-scale DER adoption 200 MW

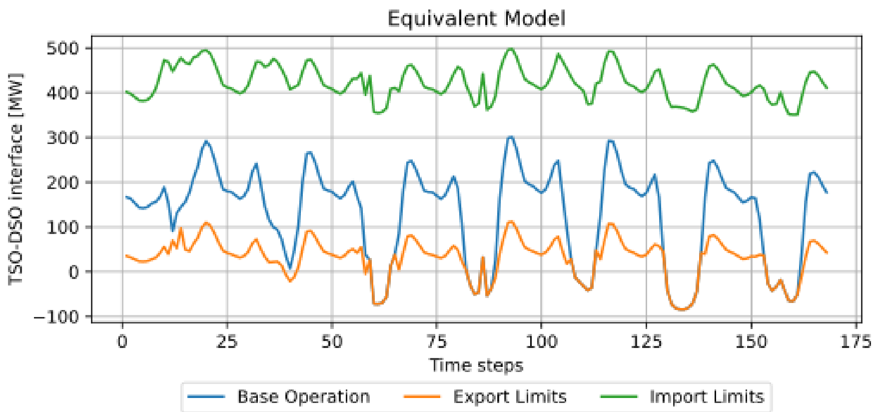


Figure 5-11: Operational limits for CBTS, large-scale DER adoption 450 MW

c. Integrated planning

This section delves into the integration of the distribution system planning methodology within transmission planning frameworks. It must be noted that the focus of this section should be on the application of the proposed methodology rather than on the quantification of benefits. The reason is that the following case studies use synthetic representations of the distribution networks, nonetheless this assumption allows for showing early insights on the value of whole system planning frameworks.

i. Trade-offs between large- and small-scale resources

As shown in previous sections, the proposed methodology allows for producing information regarding distribution system planning, which can be communicated in any transmission planning problem, allowing to decide over large- and small-scale resources within this whole-system perspective.

To showcase this approach, a case study for the state of Victoria was analysed taking as reference year 2030, aiming at comparing the benefits of developing DER in subtransmission against transmission augmentations that unlock developing large-scale solar, wind (on and offshore), and BESS within the 8 renewable energy zones (REZ) considered for Victoria as seen in Figure 5-12.

To do this, three subtransmission networks from AusNet were analysed, *CBTS*, *GNTS-MBTS*, and *SMTS* based on the results presented in Figure 5-5, where investment costs include infrastructure to support DER and the capital cost of these assets as the aim is to truly compare investments across the whole system. Moreover, in terms of large-scale investments, AEMO identifies 15 REZ augmentation options for the state of Victoria with an ***average capital cost of 0.75 $M/MW, with the highest being V6 with 2.8 $M/MW, and the lowest 0.15 $M/MW for V5*** [6].

It is worth noting that all these assumptions are based on AEMO's inputs for the ISP 2024, particularly the REZ data, and thus, results presented in this section may vary substantially from the 2025 Victorian Transmission Plan[10], expected to be published by mid-year.

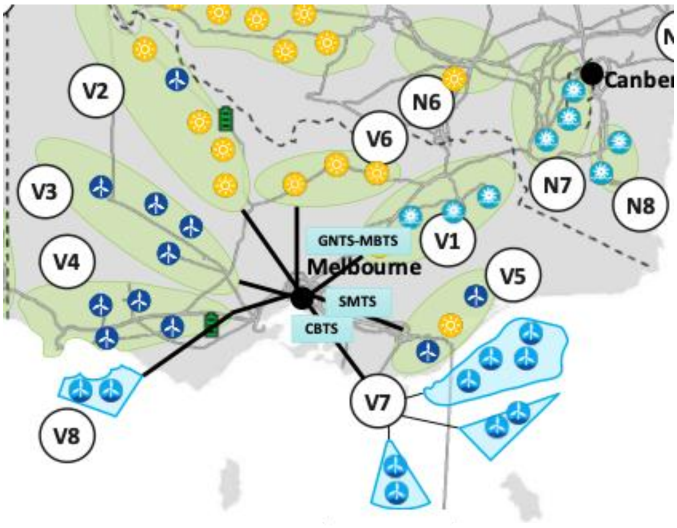


Figure 5-12: Renewable energy zones in the state of Victoria

As illustrated in Figure 5-13, if decision-making over DER is neglected, ***13.4 GW of transmission augmentations are needed, unlocking V4, V5, V6, and V7***. This is to support the development of ***100 MW of solar in V6, and 5.8 GW of wind in V4, V5, V6 and V7 (where offshore wind is developed), plus 4.1 GW of large-scale storage (4 hours) are built in V4.***

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[10] 2025 Victorian Transmission Plan. Available at: https://www.energy.vic.gov.au/renewable-energy/vicgrid/the-victorian-transmission-plan

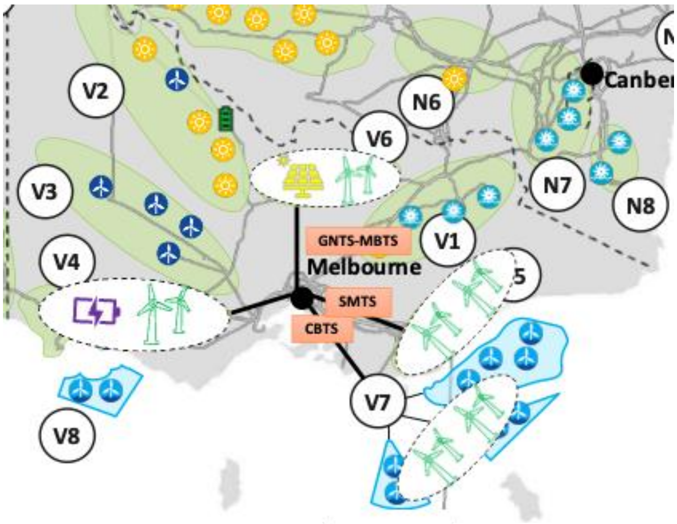


Figure 5-13: Victoria's development with no decision-making over large-scale DER

On the contrary, as seen in Figure 5-14, once we unlock the possibility of investing in DER, ***the total transmission needed is only 8 GW*, *reduction of 5.4 GW***, while developing ***800 MW of solar, and 5.4 GW of wind, with only 3.5 GW of large-scale storage, representing a reduction of 600 MW***. Therefore, from this simple case study it can be demonstrated that taking a whole-system decision-making perspective allows to develop resources across the system in a more efficient way, combining the development of large- and small-scale resources.

Moreover, one of the keys for this to happen is the hosting capacity of subtransmission networks to accommodate larger DER. Depending on this, this adoption can be supported by proactive planning and considerations of non-network solutions such as ANM, reactive compensation, and even CER coordination (not part of this analysis), reducing infrastructure costs within distribution networks. In turn, developing additional DER could avoid discussions over building transmission augmentations, which face deep uncertainties regarding construction times, costs, and social opposition.

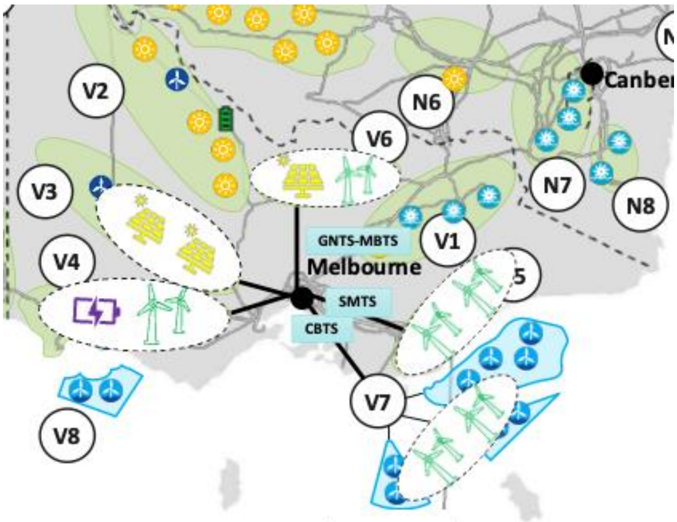


Figure 5-14: Victoria's development including decision-making over large-scale DER

ii. Methodological integration into the NEM

Going deeper into the integration of this methodology in transmission planning, a case study was developed assuming the *Step Change scenario from the inputs and assumptions from the ISP 2024* [2], as the ESP revolution and evolution scenarios are based on this. Here, the objective is delving into how coordinating CER may impact both distribution and transmission planning, highlighting how the methodology can be applied within a broader representation of the NEM. As seen in Figure 5-15, this case study considers the state of New South Wales, which is modelled by 4 subregions in the ISP, ***using the CBTS network as a synthetic representation of their distribution side***.

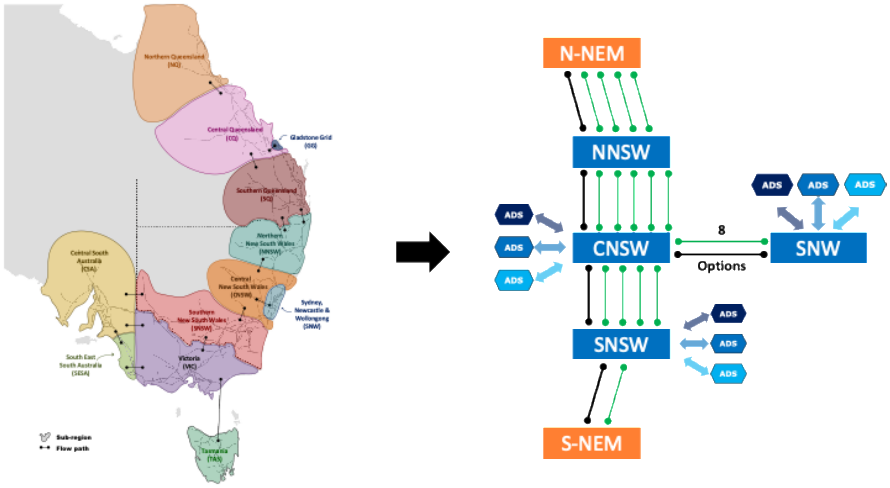


Figure 5-15: NSW representation, small case study for the NEM

We employed the ISP projections to allocate demand traces and CER adoption in this synthetic representation, producing cost functions for Central and South New South Wales, and for Sydney, Newcastle, and Wollongong. As seen in Figure 5-16, the impact of coordinating CER is huge when planning the network, deferring almost all the initial investments (no CER coordination), highlighting the importance of making usage of the expected resources, particularly the storage capacity. This coordination is modelled as rooftop PV curtailment, storage in the form of VPP (2.2 hours of duration) and demand side participation in the form of load reduction.

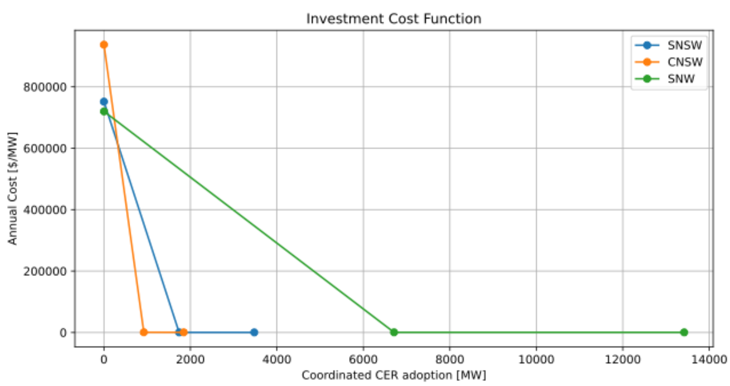
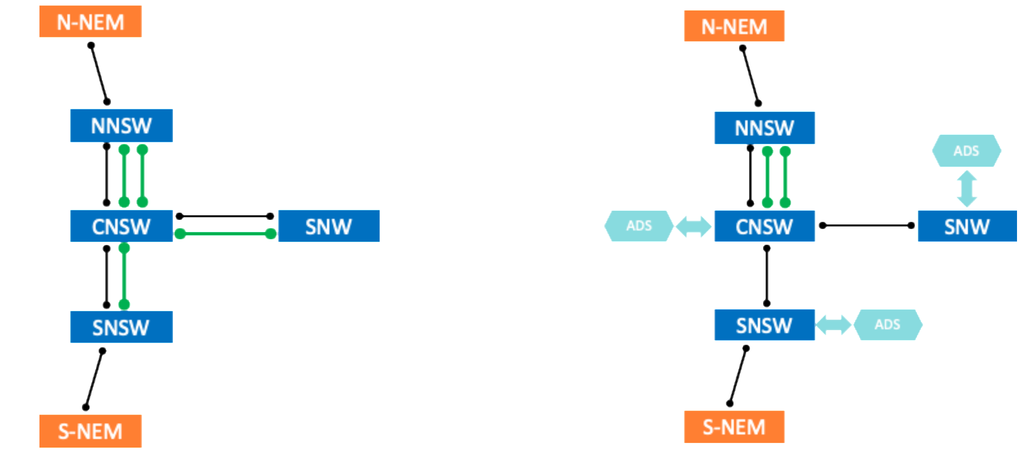


Figure 5-16: Cost functions for CNSW, SNW, and SNSW for 0%, 50%, and 100% DER coordination

This information, along with the equivalent model of each option within the parametrisation, can be communicated to the transmission planning problem. This would represent the outputs obtained from DNSPs planning their networks and communicate them to AEMO. The main outcome from this integration is the deferral of large-scale transmission investments, particularly between CNSW and SNSW, and CNSW and SNW, which along with reductions investment costs within distribution planning. In this case study, this represents a **reduction in total cost of 26% and curtailment of 5%, nonetheless, to gain certainty over the quantification of these benefits, proper representations of distribution limitations must be in place across the NEM**.



a) No decision-making over distribution

b) Decision-making over distribution

Figure 5-17: Differences in transmission expansion with whole-system perspective

Therefore, even though the results are promising, these benefits should not be considered as representative as they are based on synthetic representations of the distribution network capabilities of these subregions within the ISP. Moreover, another key aspect is how to properly model the resources that can be coordinated, particularly when focused on CER (modelled as VPP or storage of 2.2 hours), as it consists of electric vehicles, thermal storage, etc. Nevertheless, the methodology allows for enhancing coordination in an efficient manner, representing an actionable approach under current roles of system planners and operators. In this sense, DNSPs should be able to produce information of investments and operational capabilities (e.g., CER capacity available upstream, network limits, etc.) deep into distribution systems, considering the impact within MV-LV networks.

d. Consequences of CER coordination

The final insights provided in this work package relate to the value provided by CER coordination when properly modelling the flexibility available from expected distributed storage, that is BESS, EVs, domestic hot water (DHW), and heating and cooling (curtailment from rooftop PV is assumed to be available). In this vein, based on C4NET scenarios and, particularly, early outputs from WP 2.10, the modelling of storage within MV-LV networks (e.g., EVs and DHW) and how much of this is expected, was included in each subtransmission network used in this work package. However, this analysis does not consider the techno-economic impact within MV-LV networks of unlocking such CER capacity and coordination, but this needs to be accounted for to properly understand the investments and limitations deep into distribution systems, as there might be storage that is accessible upstream the network, constrained by network capacity, and available only for local services.

Figure 5-18 and Figure 5-19 illustrate the investment cost functions for reference years 2040 and 2050 respectively, using 0%, 25%, 50%, 75%, and 100% of CER coordination as parametric approach for planning the subtransmission networks, where all technologies increase the same percentage per iteration and it includes the coordination cost presented in Section 3 to unlock these resources.

Furthermore, although we are modelling and valuing the coordination of CER up to 100% to understand the impact on subtransmission networks, the participation of these resources will largely be governed by customer preferences, nonetheless, from the information produced by these results, assessments on the whole system can be carried out to understand the possible benefits that all levels of coordination can produce in terms of investment costs across the system and as a consequence, what customers would see for their willingness to be coordinated.

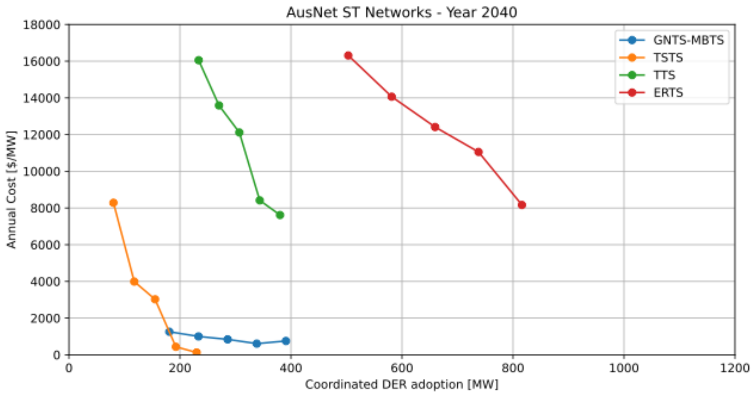


Figure 5-18: Impact of CER coordination on subtransmission network planning, reference year 2040[11]

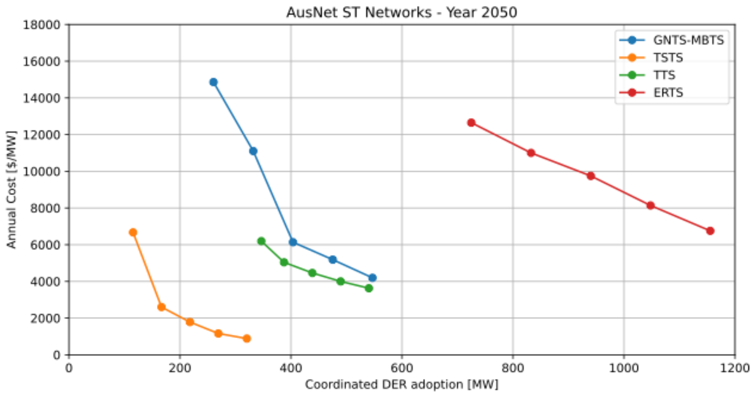


Figure 5-19: Impact of CER coordination on subtransmission network planning, reference year 2050

[11] Not all the networks have results yet but would be updated accordingly. Nevertheless, this won't affect the main conclusions drawn from this case studies

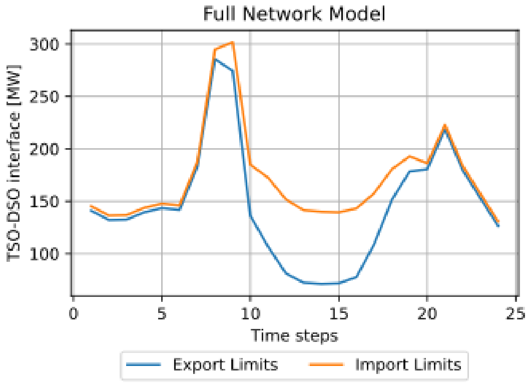
On the one hand, **in 2040** the overall reductions in total annual investment costs (network and coordination infrastructure) due CER coordination, i.e., comparing $/MW from 0% to 100% of coordination, ***account for up to 40% for GNTS-MBTS, 98% for TSTS, 53% for TTS, and 50% for ERTS***. On the other hand, **in 2050** these benefits ***account for up to 72% for GNTS-MBTS, 87% in TSTS, 41% for TTS, and 47% for ERTS***. Effectively, this means that the more CER capacity that DNSPs can coordinate, out of the expected adoption within distribution networks, the total annual investment costs will be reduced.

Therefore, coordinating expected resources allows solving several local problems that defer most of the initial investments, but these benefits will depend on the characteristics of the network (e.g., peak load, composition, topology, etc.) and its hosting capacity. This aspect is clearly reflected on networks like *TSTS* and *GNTS-MBTS*, which show the least investment costs, particularly in 2040, and are the ones with less peak load, out of all the networks analysed, and are mainly composed by rural MV-LV networks. Nevertheless, by 2050, it is shown that the level of investments in *GNTS-MBTS* greatly increase due to demand and CER surpassing its hosting capacity, requiring network reinforcements. Moreover, networks like *ERTS* and *TTS*, also benefit from CER coordination although need more investments to supply the load.

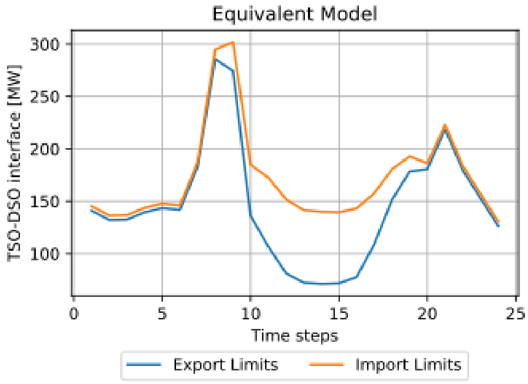
In addition, the following figures illustrate how flexible limits change for some of the networks, for 2040 and 2050, due to the investments to support demand growth and CER, as well as the coordination of these resources. It is evident both, that the equivalent model represents the flexibility limits from the network accurately, and that this flexibility can provide huge value upstream the network in an aggregated fashion.

Moreover, as aforementioned, this assessment only considers the subtransmission networks and thus, the flexibility that is found can be overestimated as some of the resources, such as EVs, DHW, distributed batteries, could be constrained by limitations of MV-LV networks unless, of course, proper investments are made at that level to unlock the full capacity of CER, but also by customer preferences to participate in the provision of services as mentioned before in this section.

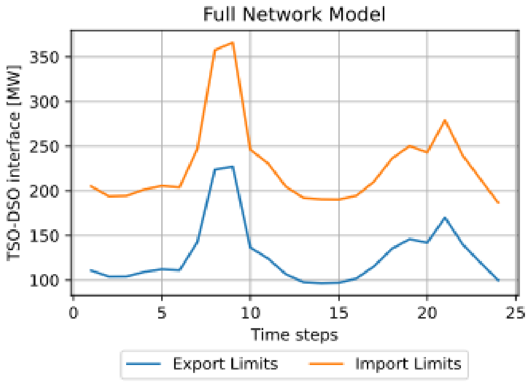
In this sense, there is a trade-off between these investments and the provision of local services by CER, and this balance would depend entirely on the objective function of the planning approach. For instance, at the extreme, DNSPs could present planning paths that allow for exploiting all these resources upstream, meaning additional investments so that CER can be fully coordinated by AEMO, and could open the possibility for considering distribution networks as investment options when planning power systems at a national level, such as within the ISP. The approach would be to plan distribution networks by just minimising costs, where CER coordination would help reducing investments for DNSPs, but the amount of flexibility that these resources could provide upstream would be limited, nevertheless benefits would come regardless due to more efficient consumption patterns in a decentralised manner.



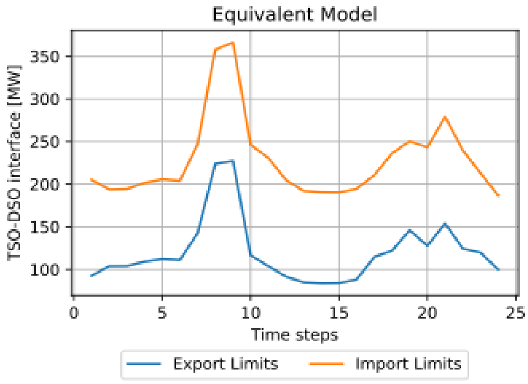
a) 0% CER coordination, network model



b) 0% CER coordination, equivalent model

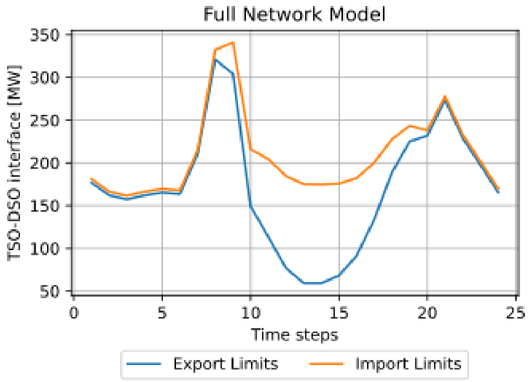


c) 100% CER coordination, network model

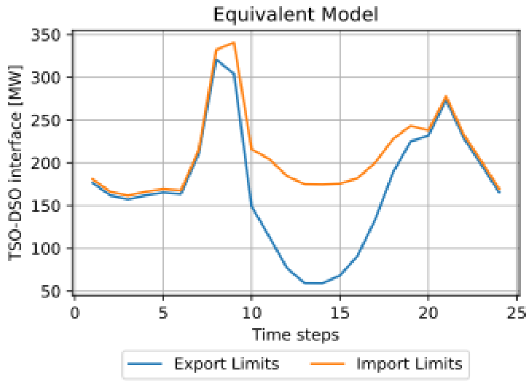


d) 100% CER coordination, equivalent model

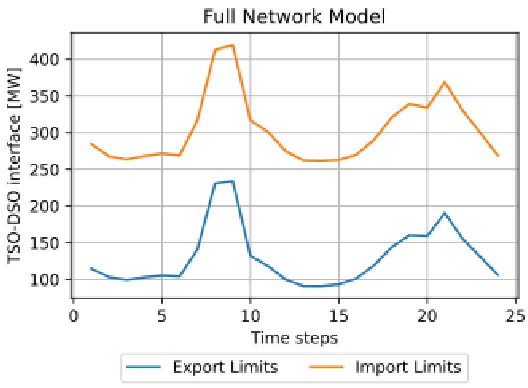
Figure 5-20: Flexibility limits of TSTS shoulder day, 2040

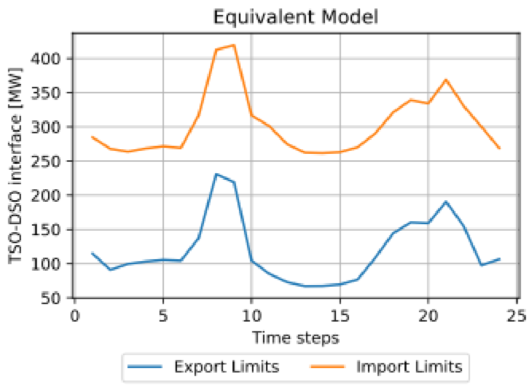


a) 0% CER coordination, network model



b) 0% CER coordination, equivalent model

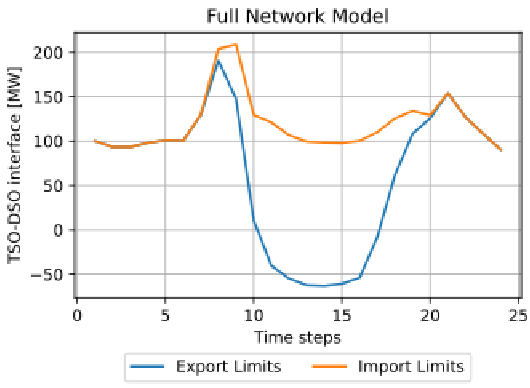


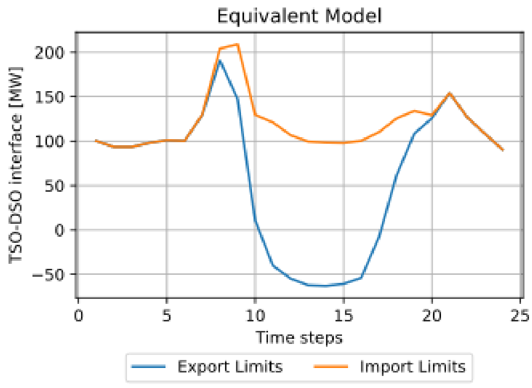


c) 100% CER coordination, network model

d) 100% CER coordination, equivalent model

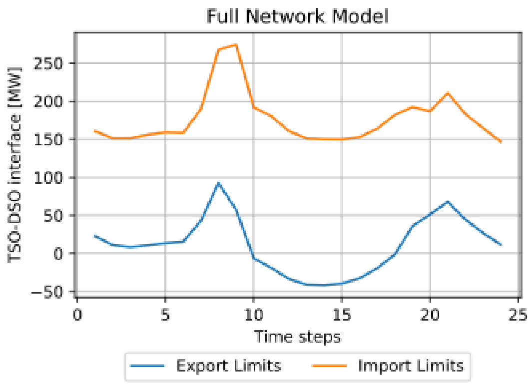
Figure 5-21: Flexibility limits of TSTS shoulder day, 2050

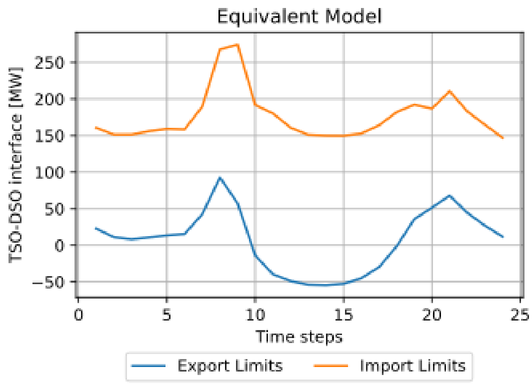




a) 0% CER coordination, network model

b) 0% CER coordination, equivalent model

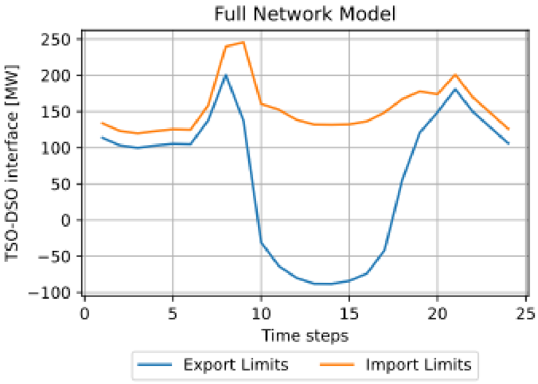




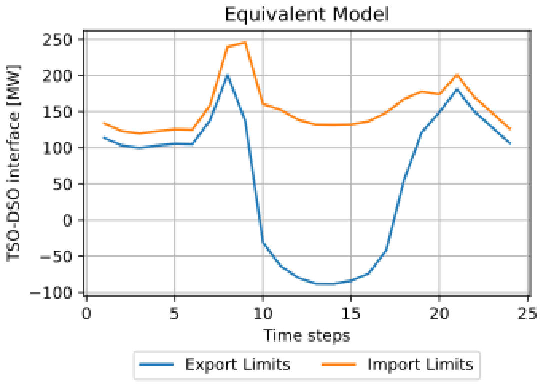
c) 100% CER coordination, network model

d) 100% CER coordination, equivalent model

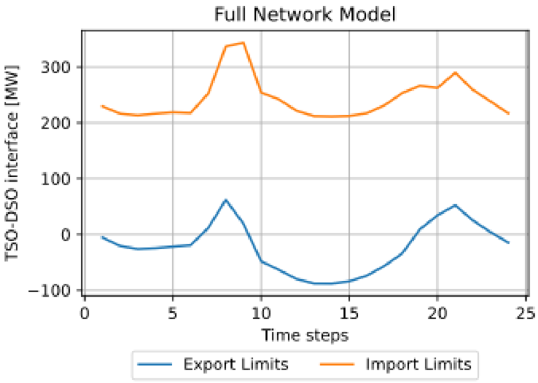
Figure 5-22: Flexibility limits of TTS shoulder day, 2040



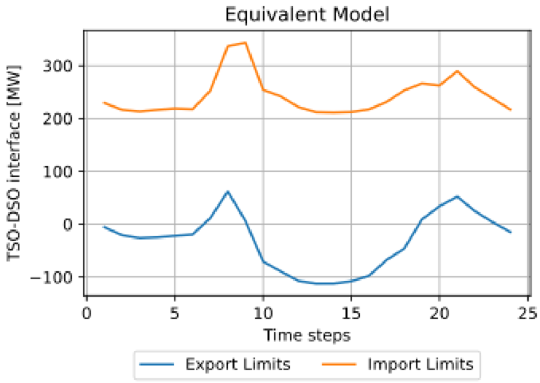
a) 0% CER coordination, network model



b) 0% CER coordination, equivalent model

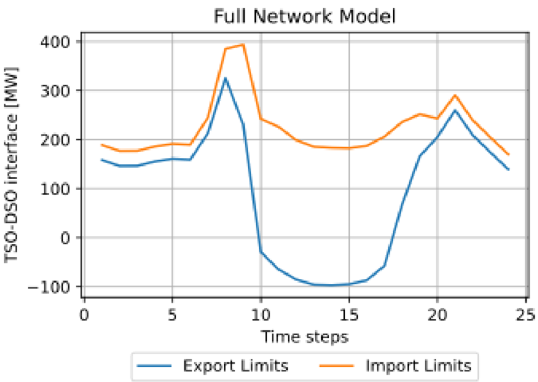


c) 100% CER coordination, network model

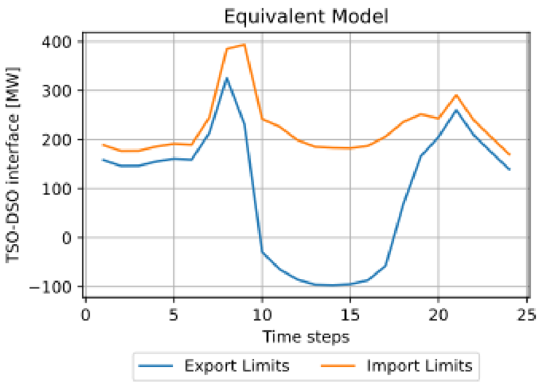


d) 100% CER coordination, equivalent model

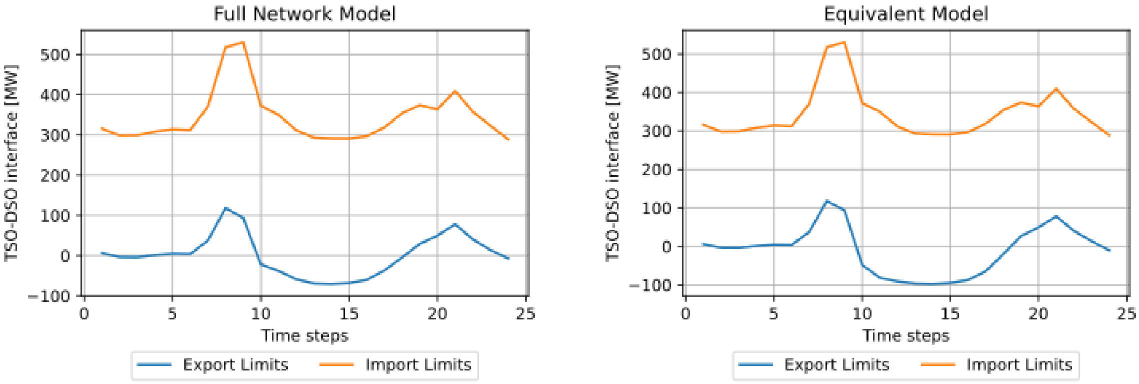
Figure 5-23: Flexibility limits of TTS shoulder day, 2050



a) 0% CER coordination, network model

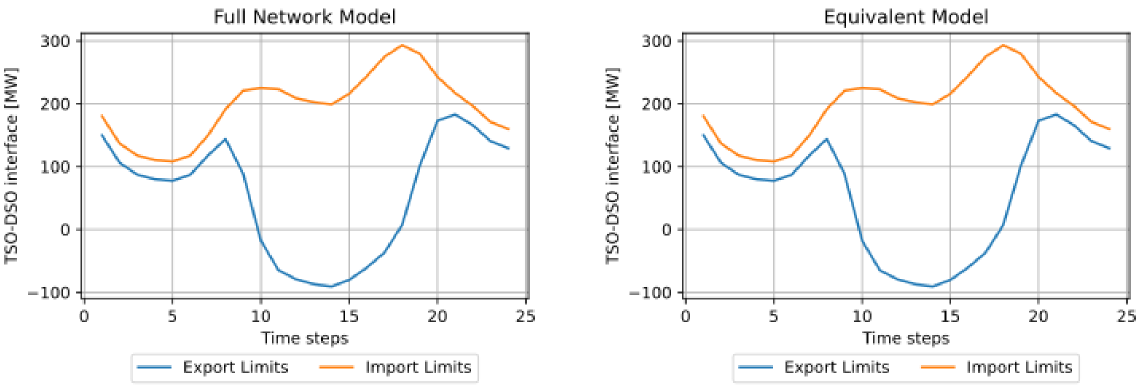


b) 0% CER coordination, equivalent model

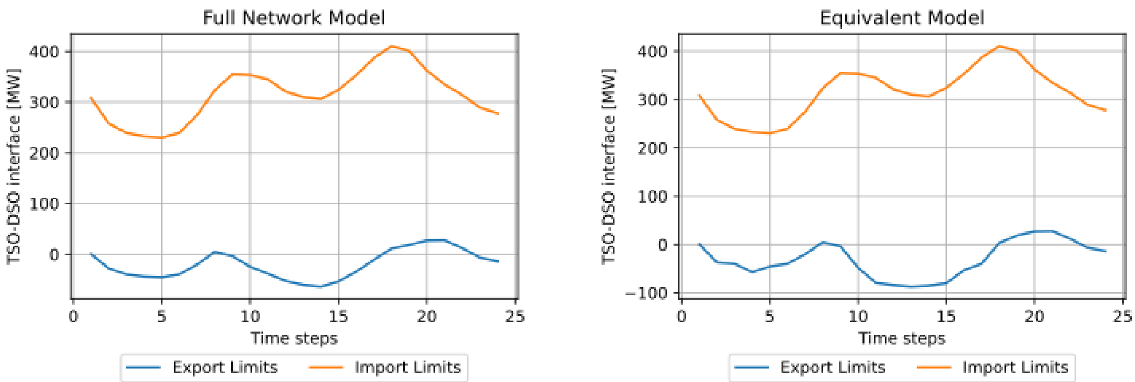


c) 100% CER coordination, network model d) 100% CER coordination, equivalent model

Figure 5-24: Flexibility limits of ERTS shoulder day, 2040



a) 0% CER coordination, network model b) 0% CER coordination, equivalent model



c) 100% CER coordination, network model d) 100% CER coordination, equivalent model

Figure 5-25: Flexibility limits of ERTS shoulder day, 2040

6. Key insights

This project proposed a bottom-up methodology for integrating distribution systems and transmission systems planning, providing clear actionable steps for the implementation of an investment coupled whole-system planning framework. This approach is based on distributing decision-making across the system, producing a parametric representation of investment requirements and operational capabilities across different distribution networks (going from LV to MV to HV networks) to support levels of DER adoption, that could represent expected scenarios, coordination of resources, etc., and hierarchically communicate this all the way up to transmission planning problems, enhancing coordination between DNSPs and system planners.

Based on this, DNSPs can independently use their own planning tools to evaluate network constraints and required investments for unlocking distributed resources and their operational flexibility (through dynamic operating envelopes and/or equivalent modelling), and share this information with system planners, such as AEMO in Australia, so that investment decisions can be made more efficiently across the entire system, leading to better resource allocation, enabling optimal decision-making for demand-side resources, DER, and distribution and transmission network reinforcements, capturing trade-offs between large- and small-scale developments.

Analyses in this work prove that there are multiple alternatives that can help in planning distribution systems. Starting off with the importance of connection schedules as taking advantage of the synergies between different technologies and location, such as solar and BESS, could reduce total investment costs. Moreover, active network management (e.g., curtailment, reactive compensation etc.) could provide a suitable alternative for DNSPs to plan their networks, transitioning into a more active role in the operation of the distribution network. Consequently, these aspects could open the door for additional large-scale DER to connect at the subtransmission level and make them more cost-effective from a whole-system perspective when compared to large-scale investments at the transmission level.

Similarly, CER coordination, modelled in the form of storage from EVs, DHW, heating/cooling, and distributed BESS, was also proven to bring benefits to subtransmission planning. Results presented in this work highlight that this coordination could illustratively displace traditional investments in network reinforcements, producing benefits (comparing 0% to 100% of CER coordination) that range from **40% to 98% in 2040**, while **41% to 87% in 2050**, depending on the characteristics of the network such as composition, topology, peak load, etc. Thus, this result underscores the importance of CER coordination as otherwise, huge benefits would be left out. Also, such benefits could open the door for additional large-scale DER to connect at the subtransmission level (less connection costs) and compete against large-scale transmission connected projects, decentralising the whole power system,

In addition, these illustrative benefits only quantify the impact on subtransmission networks and thus, a proper assessment needs to be carried out on the MV-LV level of distribution systems, as investments will be needed to unlock the flexibility from CER, or at least a portion of this capacity, as there will be trade-offs between the provision of local services and investments in network reinforcements. In this sense, DNSPs could adopt different strategies, either minimising investment costs by leveraging CER coordination, or produce portfolios with additional investments in distribution networks to enable CER participation at the transmission level, and although the latter may not be the least-cost option for the distribution network, it could unlock significant value across the entire power system by reducing the need of large-scale transmission projects.

The integration of this methodology into a whole-system planning framework was assessed through case studies that explored trade-offs between large- and small-scale resources and quantified the illustrative system-wide benefits of CER coordination. Findings indicate that DER investments can offset the need for transmission augmentation and large-scale renewable energy projects, demonstrating the efficiency of a whole-system decision-making approach. Additionally, CER coordination can reduce total system costs, particularly by deferring large-scale transmission and distribution investments.

In this context, achieving the real-world implementation of an integrated framework would bring the direct benefit of avoiding major discussions about building transmission augmentations. These large-scale project face deep uncertainties regarding construction times, costs, as well as social opposition, which can be reduced by taking advantage of the hosting capacity of subtransmission networks, CER coordination, and coordinated planning.

Although these case studies provide promising insights, achieving a fully integrated investment-coupled whole-system planning framework requires accurate representation of distribution system limitations. The benefits quantified in this study serve as a foundational step, outlining the necessary information and communication pathways needed for real-world implementation. Ultimately, DNSPs from different regions could generate parametric investment cost functions and assess operational capabilities across all levels of their distribution networks, using their own expertise and planning tools to contribute to a more coordinated and efficient energy system.

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Appendix 1: Equivalent model to represent operational capabilities of distribution systems

This section delves into the mathematical formulation employed to find the equivalent model of distribution system proposed in this work. As context, Figure 7-1 illustrates a dynamic representation of the active power associated to the operating envelope, *for each time step*, of a given distribution network. Here, the base operation, maximum imports and exports allow for capturing the time-varying parameters for the equivalent model are determined by analysing the upwards (green arrows) and downwards (orange arrows) flexibility (operational headroom) of DER.

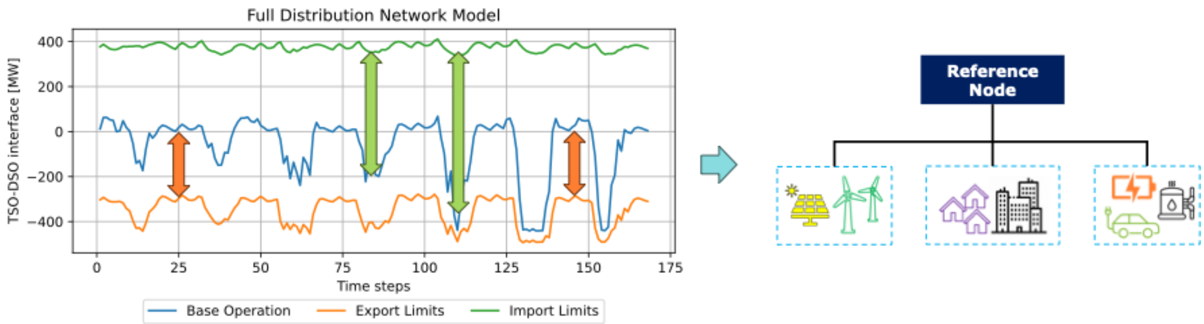

Figure 7-1: Characterisation of equivalent model according to dynamic active power operating envelope

Thus, to compute this equivalent representation of the operational capabilities of distribution networks, the following set of equations can be employed, according to the variables presented in Table 7-1.

Table 7-1: Description of variables to find equivalent model of distribution systems

Variable	Description
$P^{Eq,BESS}_{ch,t}$	Charging limit of aggregated storage component
$P^{Eq,BESS}_{dch,t}$	Discharging limit of aggregated storage component
$P^{ch,Imp}_{b,t}, P^{dch,Imp}_{b,t}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the imports case
$P^{ch,Base}_{b,t}, P^{dch,Base}_{b,t}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the base case
$P^{ch,Exp}_{b,t} - P^{dch,Exp}_{b,t}$	Charging and discharging of individual distributed storage *b*, at time *t*, for the exports case
$InstESS^{Base}_{b}, minESS^{Base}_{b}$	Installed and minimum storage capacity (MWh) for distributed storage *b*
E_{max}, E_{min}	Storage limits (MWh) of the aggregated storage component
$L^{Imp}_{DR,,t}$	Demand response scheme for flexible load *DR*, at time *t,* for imports case
$L^{Base}_{DR,t}$	Demand response scheme for flexible load *DR*, at time *t,* for base case
$L^{Exp}_{DR,t}$	Demand response scheme for flexible load *DR*, at time *t,* for exports case
$L^{Eq,DR}_{up,t}, L^{Eq,DR}_{dn,t}$	Power limits for aggregated demand response, upwards and downwards at time *t*
$P^{TSO-DSO}_{Imp,t}$	TSO-DSO power exchange, imports case, at time *t*
$Load_{t}$	Inflexible load of the equivalent model at time *t*
$Gen^{VRE}_{t}, Gen^{NonVRE}_{t}$	Generation limits at time *t*, for renewable and non-renewable component of equivalent model

$Gen_t^{Exp,VRE}, Gen_t^{Imp,VRE}$	Generation of all renewable DER at time t, for exports and imports case
$Gen_t^{Exp,NonVRE}, Gen_t^{Imp,NonVRE}$	Generation of all non-renewable DER at time t, for exports and imports case
C_{NonVRE}	Operational cost of non-renewable DER
C_{Curt}^{VRE}	Curtailment cost of renewable DER

Equations (1)-(4) determine the parameters associated to the storage component. To find the equivalent charge and discharge rating in each time-step, the base operation of every BESS is compared with the imports and exports case, respectively. As for the storage, this is equivalent to the sum of all the available storage within the system. Through the same comparison, the time-varying parameters of demand-response schemes are determined based on equations (5)-(7). Finally, equations (8)-(12) define the inflexible load, the generation component associated to renewable and non-renewable generation with their respective curtailment and operational cost.

$$P_{ch,t}^{Eq,BESS} = \sum_{b}^{BESS} (P_{b,t}^{ch,Imp} - P_{b,t}^{dch,Imp}) - (P_{b,t}^{ch,Base} - P_{b,t}^{dch,Base}) \tag{1}$$

$$P_{dch,t}^{Eq,BESS} = \sum_{b}^{BESS} (P_{b,t}^{dch,Exp} - P_{b,t}^{ch,Exp}) - (P_{b,t}^{dch,Base} - P_{b,t}^{ch,Base}) \tag{2}$$

$$E_{max} = \sum_{b}^{BESS} InstESS_b^{Base} \tag{3}$$

$$E_{min} = \sum_{b}^{BESS} minESS_b^{Base} \tag{4}$$

$$L_{up,t}^{Eq,DR} = \sum_{DR}^{Flex\ Loads} L_{DR,,t}^{Imp} - L_{DR,t}^{Base} \tag{5}$$

$$L_{dn,t}^{Eq,DR} = \sum_{DR}^{Flex\ Loads} L_{DR,,t}^{Base} - L_{DR,t}^{Exp} \tag{6}$$

$$C_{DR} = max\ C_{DR} \tag{7}$$

$$Load_t = P_{Imp,t}^{TSO-DSO} - P_{ch,t}^{Eq,BESS} - L_{up}^{Eq,DR} \tag{8}$$

$$Gen_t^{VRE} = Gen_t^{Exp,VRE} - Gen_t^{Imp,VRE} \tag{9}$$

$$Gen_t^{NonVRE} = Gen_t^{Exp,NonVRE} - Gen_t^{Imp,NonVRE} \tag{10}$$

$$C_{NonVRE} = max\ C_{NonVRE} \tag{11}$$

$$C_{Curt}^{VRE} = max\ C_{Curt}^{VRE} \tag{12}$$