Enhanced System Planning Project

C4NET | ESP Enhanced System Planning

C4NET Project Overview

Assessment of Electrification Impact for Victorian Sub-transmission, Medium and Low Voltage Networks

Work Package 1.5 & 1.6

April 2025

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1. Purpose of the report

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

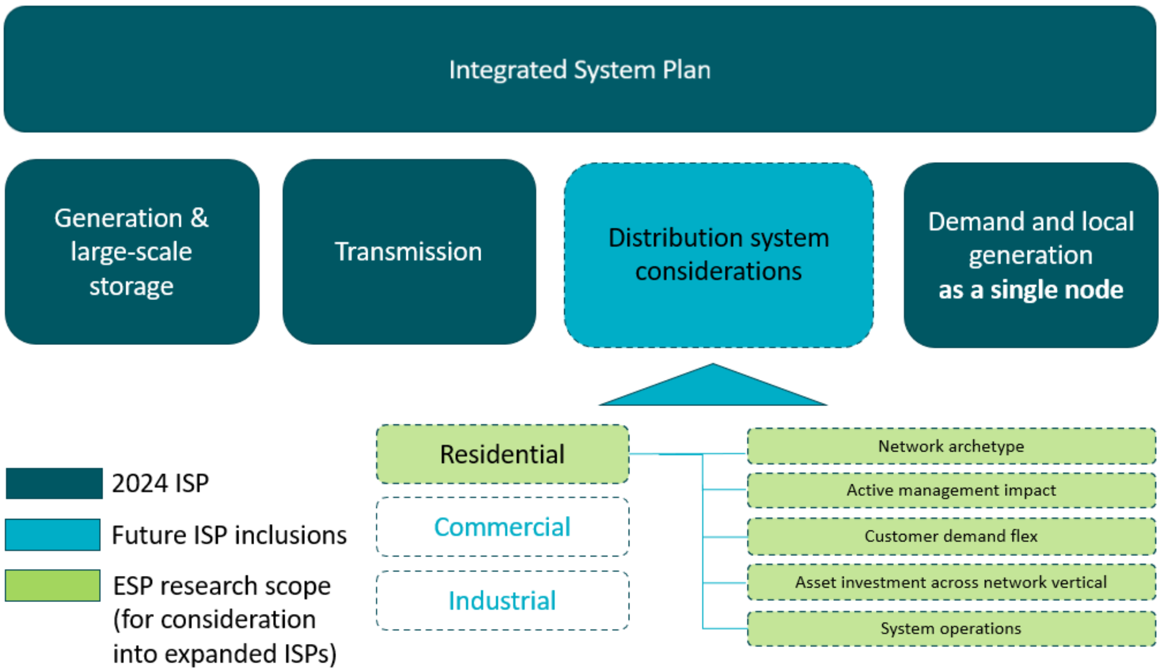

Figure 1 – Relationship between ISP and ESP

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

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

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

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

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

A key project of work package one, Melbourne University undertook two independent research projects: Integrated MV-LV Network Studies to Assess Electrification Impact (WP 1.5) and Whole-State Network Impact Assessment (WP 1.6), with the goal of estimating the quantum of future network impact of CER/DER by performing power flow studies over the time horizon from 2023 to 2053, and extrapolating the study results to cover the whole Victorian MV and LV distribution networks, and seven sub-transmission networks. The two projects used the network models developed in WP1.4 and implemented improvements to voltage control that reduced the adverse impact of CER/DER. In addition, the projects explored the use of Dynamic Operating Envelopes (DOEs) for both import and export control and demonstrated the quantum of improvement that could be achieved.

This report is designed to guide stakeholders in their understanding of the potential network challenge from the increasing penetration of CER/DER in a long-term planning perspective and how the use of DOEs can reduce the adverse impact.

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

2. Project Summary

The Assessment of Electrification Impact for Victorian Sub-transmission, Medium and Low Voltage Networks research project sought to evaluate the impacts of electrification (considering rooftop PV systems, electric vehicles, and gas electrification) in the time period from 2023 to 2053 on the Victorian electricity distribution networks. WP 1.5 focused on the impact on the MV and LV networks while WP 1.6 extended the modelling to assess the impact on seven sub-transmission networks and extrapolated WP 1.5 modelling results across the whole Victorian electricity distribution networks. The project's relationship with other research projects in Work Packages 1 is illustrated in *Figure 2* below.

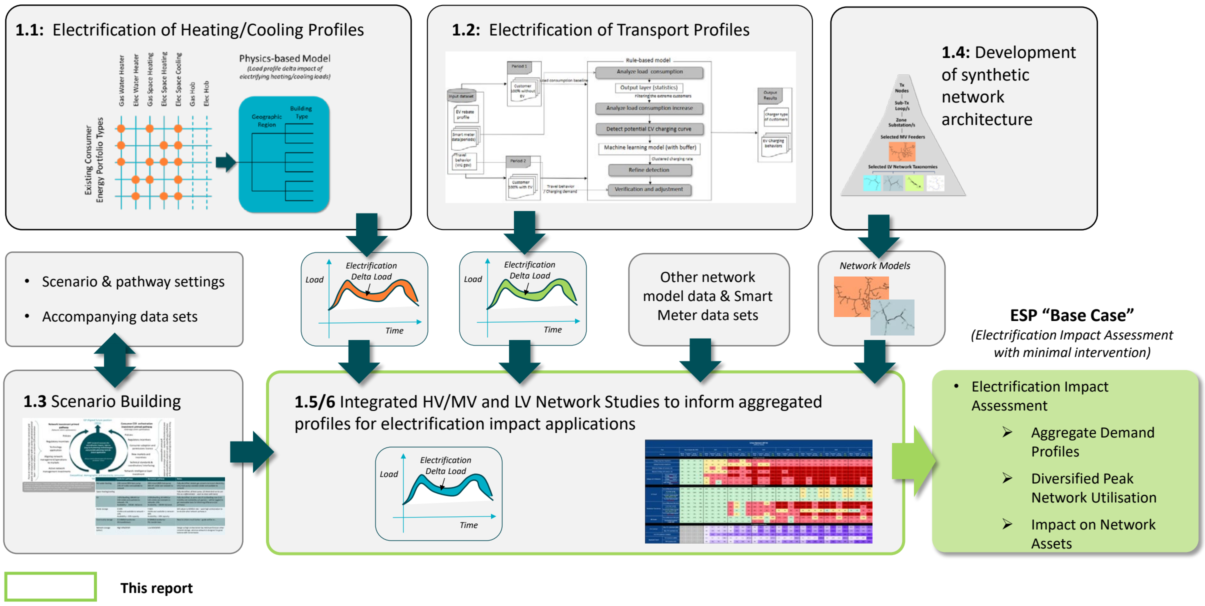

Figure 2 – Relationship between this research project and other projects in Work Package 1

Under high CER/DER penetration scenarios forecasted between 2023 to 2053[3], the project's modelling indicated that on peak summer, peak winter and spring shoulder season days high residential PV penetration caused significant voltage rise issue on the LV networks which resulted in curtailment of existing PV systems and limiting further PV uptake. The increase in peak demand from EV adoption and residential electrification (i.e., heating/cooling and hot water systems) further exacerbated voltage issues (voltage drop) and caused significant asset overloading across the whole electricity distribution network from terminal stations, sub-transmission lines, zone substation transformers, MV lines and distribution transformers. While only slight overloads were found on LV lines, the modelling might have underestimated LV conductor utilisation by adopting the modern design of LV conductors in the pseudo-LV networks (featuring lower impedance and higher ampacity) provided by WP 1.4.

[3] C4NET Scenario Planning Data

Significant investment in augmenting the capacity of the distribution networks is deemed required to meet the forecasted uptake of CER/DER, between now and 2053. Summarised in Tables 1 & 2 are the impact tables for one terminal station (East Rowville Terminal Station, or ERTS) and extrapolation result for MV/LV across the state of Victoria. Colour coding is used to indicate the relative seriousness of the impact (green – OK, yellow – starting to have issue, orange – issue becomes more serious, red – issue is serious; and darker shade of the same colour implies progressively more impact).

Sub-transmission Network – ERTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations in WP1.6)									
Maximum Demand at Terminal Station (MVA)			504	653	906	1254	1631	2049	2350
Increase of Max. Demand at Terminal Station (MVA)			-	30%	39%	38%	30%	26%	15%
Power Factor at Terminal Station for Max. Demand			1.00	0.97	0.91	0.83	0.77	0.69	0.64
HV Voltage Assessment (model-based simulations in WP1.6)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	26%	43%
Maximum Voltage (pu)			1.06	1.08	1.08	1.08	1.08	1.08	1.08
Minimum Voltage (pu)			0.98	0.98	0.98	0.97	0.94	0.75	0.71
HV Thermal Assessment (model-based simulations in WP1.6)									
Zone substations Transformers	% of Transformers with Maximum Utilisation	<= 100%	88%	88%	65%	47%	47%	47%	47%
		100%-110%	12%	0%	12%	6%	0%	0%	0%
		Avg. Overloading Duration (hr)	3	0	3.3	4	0	0	0
		110%-150%	0%	12%	12%	24%	29%	0%	0%
		Avg. Overloading Duration (hr)	0	5.5	5	6.6	13.5	0	0
		> 150%	0%	0%	12%	24%	24%	53%	53%
		Avg. Overloading Duration (hr)	0	0	4.5	6	13.9	10.2	14.2
	Max. Utilisation of the Worst Performing Transformer		110%	150%	187%	282%	302%	307%	318%
Sub-transmission lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	94%	75%	75%	62%	44%
		100%-110%	0%	0%	6%	6%	0%	12%	12%
		Avg. Overloading Duration (hr)	0	0	4	2.5	0	1	0.5
		110%-150%	0%	0%	0%	19%	12%	0%	19%
		Avg. Overloading Duration (hr)	0	0	0	5.8	6.8	0	1.2
		> 150%	0%	0%	0%	0%	12%	25%	25%
		Avg. Overloading Duration (hr)	0	0	0	0	4.3	9	12.1
	Max. Utilisation of the Worst Performing Line		66%	81%	108%	133%	168%	205%	241%
MV-LV Voltage Assessment (extrapolation of metrics using results from WP1.5)									

Residential Voltage Rise Non-Compliance		0%	1%	3%	5.3%	9%	12%	14%
Residential Voltage Drop Non-Compliance		1%	3%	9%	14%	19%	23%	26%
% of LV Networks with Voltage Rise Issues		1%	12%	20%	24%	26%	28%	28%
% of LV Networks with Voltage Drop Issues		12%	22%	26%	30%	34%	41%	45%
% of LV Networks with Both Voltage Rise & Drop Issues		1%	12%	20%	24%	25%	28%	28%
MV-LV Thermal Assessment (extrapolation of metrics using results from WP1.5)								
% of Distribution Transformers with Maximum Utilisation	<= 100%	100%	97%	82%	67%	61%	56%	54%
	100%-110%	0%	3%	7%	4%	4%	3%	2%
	110%-150%	0.2%	0.2%	11%	22%	17%	11%	11%
	> 150%	0%	0.2%	0.3%	6%	18%	30%	33%
PV Curtailment Assessment (extrapolation of metrics using results from WP1.5)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	28	55	84	120	163	216	268
	% of PV Curtailment	6%	9%	12%	15%	18%	21%	24%

Table 1 - Impact of CER/DER on distribution networks supplied from ERTS 2023-2053, without DOEs

Whole-State (211 ZSS out of 246) (without DOEs)								
Year		2023	2028	2033	2038	2043	2048	2053
Voltage Assessment								
Residential Voltage Rise Non-Compliance	All ZSS	0.2%	1%	4%	6%	10%	12%	16%
	<50 MVA	0.2%	2%	4%	7%	10%	13%	18%
	50-100 MVA	0.2%	2%	4%	7%	10%	12%	16%
	>100 MVA	0.1%	1%	3%	5%	8%	11%	13%
Residential Voltage Drop Non-Compliance	All ZSS	2%	4%	9%	13%	18%	22%	26%
	<50 MVA	2%	4%	9%	13%	17%	21%	27%
	50-100 MVA	2%	4%	9%	13%	18%	22%	26%
	>100 MVA	1%	3%	9%	14%	18%	23%	25%
% of LV Networks with Voltage Rise Issues	All ZSS	0.7%	8%	13%	15%	16%	18%	21%
	<50 MVA	0.6%	5%	9%	10%	11%	13%	18%
	50-100 MVA	0.7%	9%	14%	16%	18%	20%	22%
	>100 MVA	0.8%	11%	18%	21%	23%	26%	28%
% of LV Networks with Voltage Drop Issues	All ZSS	8%	14%	17%	20%	23%	28%	36%
	<50 MVA	5%	10%	12%	14%	17%	21%	31%
	50-100 MVA	9%	15%	18%	21%	25%	30%	37%
	>100 MVA	11%	20%	23%	26%	31%	38%	45%

% of LV Networks with Both Voltage Rise & Drop Issues		All ZSS	0.7%	8%	13%	15%	16%	18%	20%
		<50 MVA	0.6%	5%	9%	10%	11%	12%	16%
		50-100 MVA	0.7%	9%	14%	16%	17%	19%	21%
		>100 MVA	1%	13%	22%	26%	27%	30%	31%
Thermal Assessment									
% of Distribution Transformers with Maximum Utilisation	<= 100%	All ZSS	99%	96%	86%	76%	70%	64%	62%
		<50 MVA	99%	96%	89%	81%	76%	70%	67%
		50-100 MVA	99%	96%	86%	75%	69%	63%	62%
		>100 MVA	100%	96%	76%	58%	51%	46%	45%
	100%-110%	All ZSS	0.4%	2%	5%	4%	3%	3%	3%
		<50 MVA	1%	1%	3%	3%	3%	3%	3%
		50-100 MVA	0.4%	2%	5%	4%	3%	3%	2%
		>100 MVA	0.2%	4%	9%	5%	4%	4%	2%
	110%-150%	All ZSS	0.5%	1%	8%	15%	13%	11%	11%
		<50 MVA	0.6%	2%	6%	10%	10%	11%	11%
		50-100 MVA	0.4%	1%	8%	16%	13%	11%	11%
		>100 MVA	0.1%	0.5%	15%	29%	22%	12%	12%
	> 150%	All ZSS	0%	0.5%	2%	6%	14%	22%	25%
		<50 MVA	0%	0.7%	2%	6%	11%	17%	19%
		50-100 MVA	0%	0.4%	1%	6%	14%	23%	25%
		>100 MVA	0%	0.1%	0.5%	8%	23%	38%	42%
PV Curtailment									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		410	793	1218	1733	2353	3123	3878
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	24%

Table 2 - Whole state extrapolation of the Impact of CER/DER 2023-2053, without DOEs, using results from WP1.5

To reduce the adverse impact of increasing CER/DER, the research project modelled the use of Dynamic Operating Envelopes (DOEs) for both import and export control at residential premises. The modelling indicated that export DOEs effectively mitigated voltage rise issue caused by high residential PV penetration although at the expense of increasing PV export curtailment. Import DOEs, on the other hand, was modelled for Level 2 EV charging. It was effective initially but as demand from electrification of gas heating and hot water became more significant, non-compliant voltage drops and heavy network asset utilisation resurfaced. Overall, the use of DOEs reduces the impact of high CER/DER penetration and hence the investment required to address the issues arising.

Tables 3 & 4 are the impact tables for ERTS and extrapolation result for MV/LV across the state of Victoria with DOEs applied:

Sub-transmission Network – ERTS (With DOEs)									
Year			**2023**	**2028**	**2033**	**2038**	**2043**	**2048**	**2053**
Terminal Station Assessment (model-based simulations in WP1.6)									
Maximum Demand at Terminal Station (MVA)			504	653	896	1189	1462	1858	2032
Increase of Max. Demand at Terminal Station (MVA)			-	30%	37%	33%	23%	27%	9%
Power Factor at Terminal Station for Max. Demand			1.00	0.97	0.90	0.84	0.80	0.74	0.71
Sub-transmission Voltage Assessment (model-based simulations in WP1.6)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	17%	26%
Maximum Voltage (pu)			1.06	1.08	1.08	1.08	1.08	1.08	1.08
Minimum Voltage (pu)			0.98	0.98	0.98	0.97	0.96	0.80	0.74
Sub-transmission Network Thermal Assessment (model-based simulations in WP1.6)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	88%	88%	71%	47%	47%	47%	47%
		100%-110%	12%	0%	6%	6%	0%	0%	0%
		Avg. Overloading Duration (hr)	3	0.0	3	1	0	0	0
		110%-150%	0%	12%	12%	24%	29%	12%	0%
		Avg. Overloading Duration (hr)	0	4.5	5.5	3.5	10.5	17.3	0
		> 150%	0%	0%	12%	24%	24%	41%	53%
		Avg. Overloading Duration (hr)	0	0	6	5.9	13.5	10	10.2
	Max. Utilisation of the Worst Performing Transformer		110%	137%	194%	232%	271%	303%	313%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	94%	81%	75%	75%	62%
		100%-110%	0%	0%	6%	0%	0%	0%	12%
		Avg. Overloading Duration (hr)	0	0	4	0	0	0	1
		110%-150%	0%	0%	0%	19%	12%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	5.8	5.8	0	0
		> 150%	0%	0%	0%	0%	12%	25%	25%
		Avg. Overloading Duration (hr)	0	0	0	0	1.8	5.6	9.4
	Max. Utilisation of the Worst Performing Line		66%	81%	106%	129%	156%	204%	207%
MV-LV Voltage Assessment (extrapolation of metrics using results from WP1.5)									
Residential Voltage Rise Non-Compliance			0.1%	1%	2%	3%	4%	5.1%	4%
Residential Voltage Drop Non-Compliance			1%	3%	8%	12%	15%	20%	24%
% of LV Networks with Voltage Rise Issues			1%	11%	17%	18%	16%	19%	19%
% of LV Networks with Voltage Drop Issues			12%	21%	26%	28%	31%	35%	39%

			2023	2028	2033	2038	2043	2048	2053
% of LV Networks with Both Voltage Rise & Drop Issues			1%	11%	17%	18%	16%	18%	18%
MV-LV Thermal Assessment (extrapolation of metrics using results from WP1.5)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	97%	85%	68%	64%	60%	56%
		100%-110%	0%	3%	4%	7%	3%	4%	4%
		110%-150%	0.2%	0.2%	11%	22%	19%	13%	12%
		> 150%	0%	0.2%	0.3%	3%	13%	23%	28%
PV Curtailment Assessment (extrapolation of metrics using results from WP1.5)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		38	65	125	244	336	450	536
	% of PV Curtailment		6%	8%	13%	23%	28%	33%	36%
EV Management Assessment (extrapolation of metrics using results from WP1.5)									
% of EVs Affected			-	-	9%	13%	16%	21%	24%
Average EV Charging Delay (h)			-	-	3.7	5.2	5.6	5.5	5.4

Table 3 - Impact of CER/DER on distribution networks supplied from ERTS 2023-2053, with DOEs

Whole-State (211 ZSS out of 246) (with DOEs)								
Year		**2023**	**2028**	**2033**	**2038**	**2043**	**2048**	**2053**
Voltage Assessment								
Residential Voltage Rise Non-Compliance	**All ZSS**	0.2%	1%	3%	4%	5.1%	6%	7%
	<50 MVA	0.2%	1%	3%	5.1%	6%	6%	10%
	50-100 MVA	0.2%	1%	3%	5%	5.4%	6%	7%
	>100 MVA	0.1%	0.9%	2%	3%	4%	5%	3%
Residential Voltage Drop Non-Compliance	**All ZSS**	2%	4%	7%	11%	14%	19%	24%
	<50 MVA	2%	4%	7%	11%	14%	19%	25%
	50-100 MVA	2%	4%	7%	11%	14%	19%	24%
	>100 MVA	1%	3%	7%	11%	15%	20%	23%
% of LV Networks with Voltage Rise Issues	**All ZSS**	0.7%	7%	11%	11%	11%	13%	15%
	<50 MVA	0.6%	5%	7%	8%	7%	9%	14%
	50-100 MVA	0.7%	8%	12%	12%	11%	13%	16%
	>100 MVA	0.8%	10%	15%	16%	14%	17%	19%
% of LV Networks with Voltage Drop Issues	**All ZSS**	8%	14%	16%	18%	21%	25%	32%
	<50 MVA	5%	9%	11%	13%	16%	20%	29%
	50-100 MVA	9%	15%	17%	19%	23%	27%	33%
	>100 MVA	11%	19%	23%	24%	29%	30%	38%
	All ZSS	0.7%	7%	11%	11%	11%	12%	14%

% of LV Networks with Both Voltage Rise & Drop Issues		<50 MVA	0.6%	5%	7%	8%	7%	8%	12%
		50-100 MVA	0.7%	7%	12%	12%	11%	13%	15%
		>100 MVA	1%	11%	18%	19%	17%	19%	20%
Thermal Assessment									
% of Distribution Transformers with Maximum Utilisation	<= 100%	All ZSS	99%	96%	89%	77%	73%	69%	66%
		<50 MVA	99%	96%	91%	83%	80%	75%	72%
		50-100 MVA	99%	96%	88%	76%	73%	68%	65%
		>100 MVA	100%	96%	81%	59%	54%	50%	46%
	100%-110%	All ZSS	0.4%	2%	3%	5%	3%	4%	4%
		<50 MVA	0.7%	1%	2%	4%	2%	4%	4%
		50-100 MVA	0.4%	2%	3%	5%	3%	4%	4%
		>100 MVA	0.2%	3%	5%	9%	4%	5%	4%
	110%-150%	All ZSS	0.5%	1%	7%	14%	14%	11%	11%
		<50 MVA	0.6%	2%	5%	9%	10%	9%	10%
		50-100 MVA	0.4%	1%	8%	15%	14%	11%	11%
		>100 MVA	0.1%	0.5%	14%	28%	25%	16%	14%
	> 150%	All ZSS	0%	0.5%	1%	4%	10%	16%	20%
		<50 MVA	0%	0.7%	2%	4%	8%	12%	14%
		50-100 MVA	0%	0.4%	1%	4%	10%	17%	20%
		>100 MVA	0%	0.1%	0.5%	4%	17%	30%	35%
PV Curtailment									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		581	983	1865	3656	4974	6600	7872
	% of PV Curtailment		6%	8%	13%	22%	27%	32%	34%
EV Management									
Percentage of EVs Affected			-	-	9%	13%	16%	20%	24%
Average EV Charging Delay (h)			-	-	3.5	5	5.3	5.2	5.1

Table 4 - Whole state extrapolation of the Impact of CER/DER 2023-2053, with DOEs, using results from WP1.5

3. Research methodology and approach

In the research project WP 1.5, the challenges created by increased adoption of CER/DER on LV and MV distribution networks were simulated for the period from 2023 to 2053. Power flow simulations were carried out on the MV/LV network models of four actual Victorian DNSP MV feeders covering urban, suburban, short-rural and long-rural feeder categories. The LV circuits for each MV feeder are modelled using a pseudo-LV network approach due to the lack of complete LV network electrical data and the extensive diversity of LV network topologies. Detailed commentary of the network modelling approach can be found in the summary report of WP 1.4[4]. A comparison of the simulation results comparing pseudo-LV network approach with ten real LV networks can be found in Appendix 5.

Research project WP 1.6 used the LV and MV network models developed in WP 1.5 and extend the impact assessment to seven sub-transmission networks covering Cranbourne Terminal Station (CRTS), East Rowville Terminal Station (ERTS), Glenrowan Terminal Station (GNTS), Mount Beauty Terminal Station (MBTS), Thomastown Terminal Station (TTS), South Morang Terminal Station (SMTS) and Templestowe Terminal Station (TSTS). The impact assessment covered the transformers and lines from the terminal stations through to the zone substations (ZSSs).

The relationship between power flow simulations for WP 1.5 and WP 1.6 is illustrated in Figure 3.

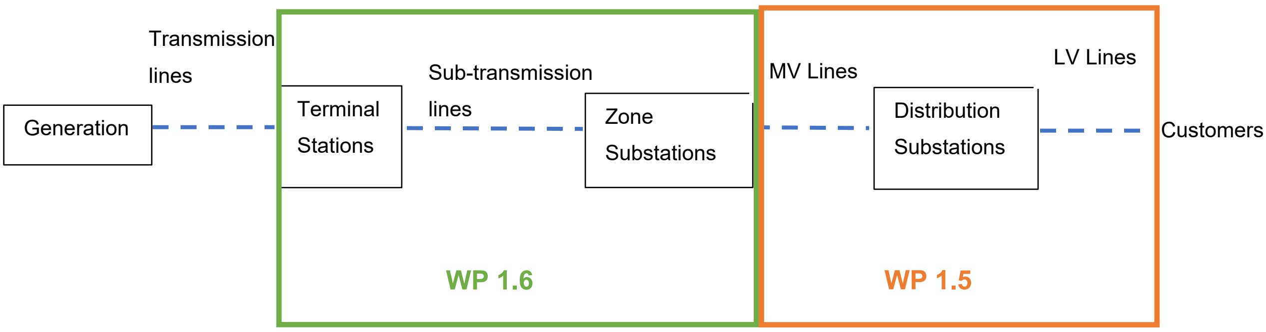

Figure 3 – Relationship between WP1.5 and WP1.6

WP 1.6 also assessed the Victoria-wide impact of CER/DER on LV/MV networks by extrapolating the four MV/LV feeder network results of WP 1.5.

For the impact assessment, power flow simulations were carried out for two scenarios: a base scenario and an alternate scenario with the application of Dynamic Operating Envelopes (DOEs) – Import and Export - to LV customers.

3.1 Methodology

The project methodologies are depicted in Figures 4 & 5 and briefly described below:

[4] C4NET project overview: Development of illustrative distribution network models for Victoria, March 2025

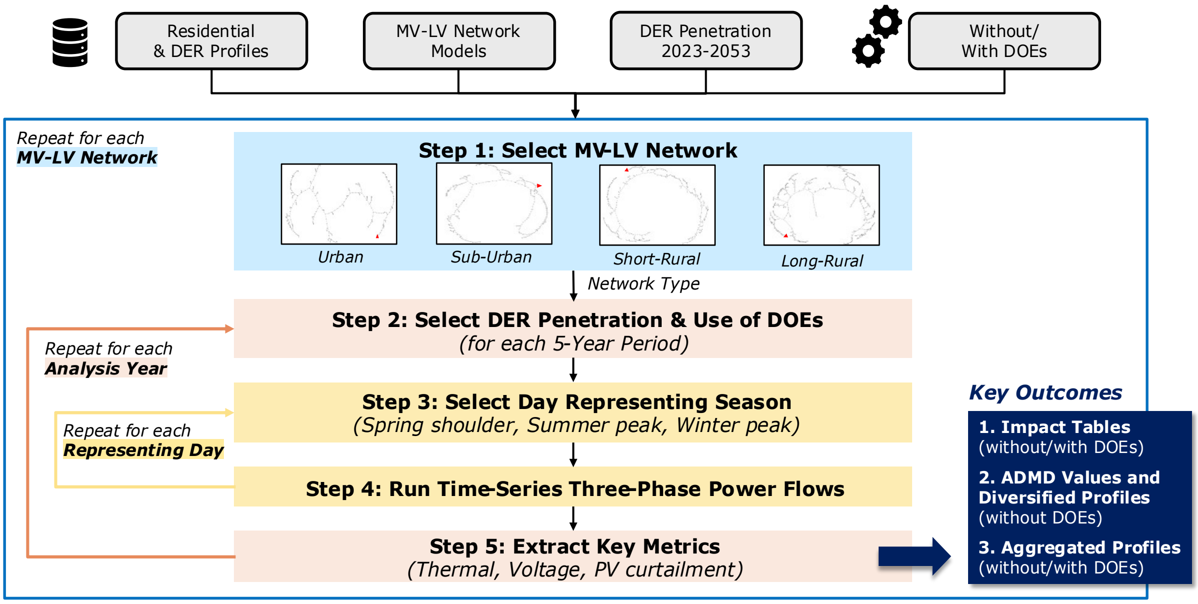

Figure 4 - Project methodology for WP 1.5

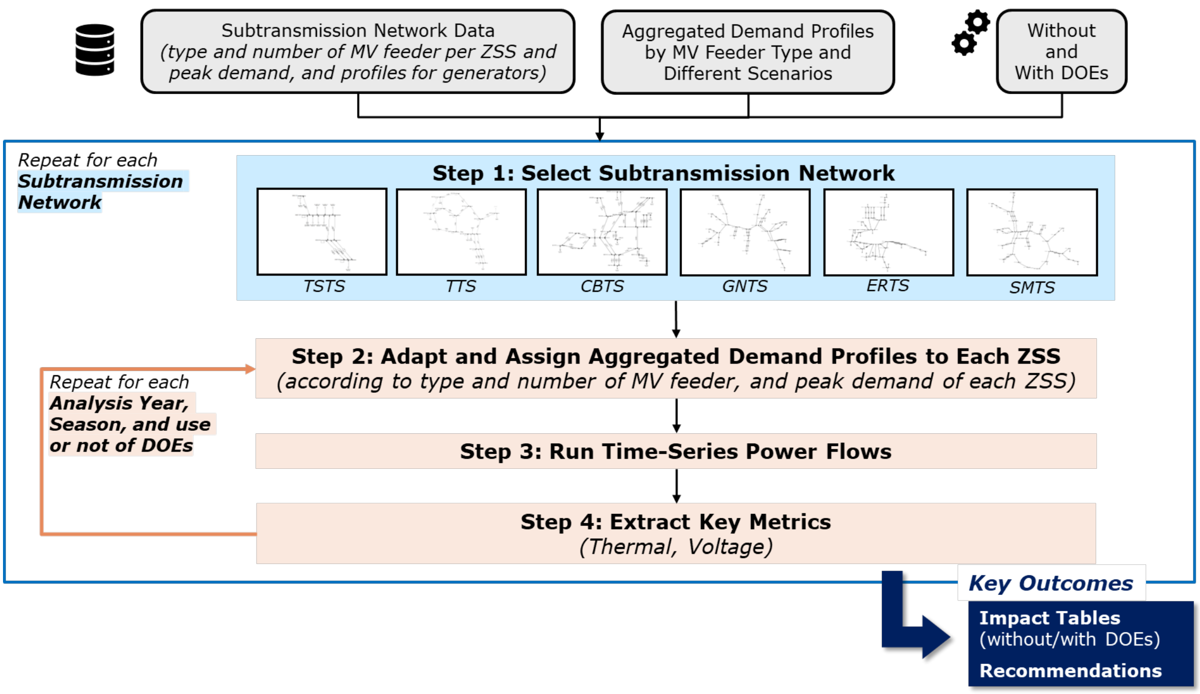

Figure 5 - Project methodology for WP 1.6

3.1.1 Inputs – Scenario Planning Data

The modelling covered the time period from 2023 to 2053. Power flow simulations were performed for 2023, and the last year of each subsequent 5-year block i.e. 2028, 2033, 2038, 2043, 2048 and 2053. The modelling of households and DERs for each analysis year was based on original scenario planning data provided by C4NET. The planning data was based on the published inputs for the 2024 ISP "Step Change" scenario and interpolating within this for the residential sector and accelerating electrification of domestic heating/cooling and hot water to saturation in 2053 with a straight-line increase from 2023. The table of scenario data used in WP 1.5 is summarised in Appendix 2 of the research report[5].

3.1.2 Inputs – Network Data

- **MV-LV Network Types:** The study examined four MV-LV distribution networks, corresponding to four geographic areas: Urban, Sub-Urban, Short-Rural, and Long-Rural. CBD network models were also considered; however, they were excluded from analysis because this would have required a different set of scenario parameters and assumptions to the other networks. The vastly different nature of prospective CER deployments suggested that this network "type" required its own independent analysis and could not reasonably be compared with the other network types. The adopted network models, initially developed in WP 1.4, were modified in WP 1.5 for operational analysis[6].
- **Analysis Year and DER Uptake:** The impact assessment was conducted every five years across the study horizon (i.e., 2023–2053), resulting in seven analysis years. For each analysis year, futuristic DER uptake data of PV, EV, gas electrification were sourced from the Scenario Planning conducted by C4NET[7].
- **Representing Day:** For each analysis year, three representing days were selected to capture demand and generation seasonality as well as different network challenges. These included a Spring Shoulder Day, a Summer Peak Day, and a Winter Peak Day. Different residential demand and DER profiles were applied to each representing day comprising 30-minute energy data randomly selected from a large set of smart meter data from premises without CER and not specifically related to a given network type[8]. The choice of representing day was based on days which were more likely to expose both thermal and voltage issues arising from the electrification of gas and the transport sector.
- **Assign and Adapt Net Demand Profiles to Each ZSS:** Considering the demand profiles for the four types of MV feeders, three peak demand days, seven analysis years, and using the type and number of MV feeders connected to each ZSS, this step built an initial demand profile for each ZSS by summing the relevant MV feeder profiles. For example, if a ZSS had two urban MV feeders, their sum created the initial ZSS demand profile for a given day and year without DOEs. Then, using the known original peak demand for each ZSS, the initial ZSS demand profiles were adapted to match the corresponding peak demands, ensuring accurate representation of loading conditions.
- **Sub-transmission Networks:** This process was repeated for every ZSS of the selected sub-transmission network, and it was done for both active and reactive power.

[5] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, Appendix 2, pages 68-69
[6] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, Section 3a, page 26
[7] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, Section 3b, page 31
[8] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, Section 3c, page 31

3.1.3 Inputs – Modelling Use of DOEs

A DOE is a limit on the power that can be imported or exported at any point in time to avoid sustained breach of operational limits. While they could be applied at a premises level, they have been interpreted here as only applying to specific loads which can be controlled through their inverters - the export from solar and the rate at which EVs are charging. They are dynamic in that they are only applied if and when the network is experiencing constraint. If applied, they would temporarily limit solar export (in effect, curtailing the solar generated to just what the house is consuming and the available export limit), or in the case of EV charging temporarily lowering the charge rate of the EV (in effect meaning it would take longer to charge).

DOEs are emerging as a key strategy for managing DER while ensuring network integrity and is expected to be widely implemented across Victoria in the coming years. To evaluate its effectiveness and provide recommendations for implementation, this study compares the impacts of electrification under two scenarios: “Without DOEs” and “With DOEs”.

- Scenario 1 (Without DOEs): Only embedded PV inverter functions (i.e. Volt-Watt and Volt-Var, following AS/NZS4777.2:2020 Australia A settings) are implemented as non-network solutions to manage PV generation, reflecting current approach adopted by Victorian DNSPs.
- Scenario 2 (With DOEs): In addition to existing PV inverter functions, both Export DOEs and Import DOEs are introduced to manage PV generation and EV charging respectively[9].

A rule-based approach was used to calculate DOEs, which heuristically examined different limit values through power flow simulations at each time interval until it found an adequate limit value that could maintain network integrity (i.e., complying with network constraints). DOEs were allocated based on an “Equal Allocation” strategy i.e. all flexible customers within the same LV network were given the same DOE values. Both export and import DOEs were assumed to be calculated at the meter level (i.e. as a limit for the household net demand), and these DOEs were calculated for active power only, as reactive power is not considered controllable.

[9] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, Section 2c, page 21

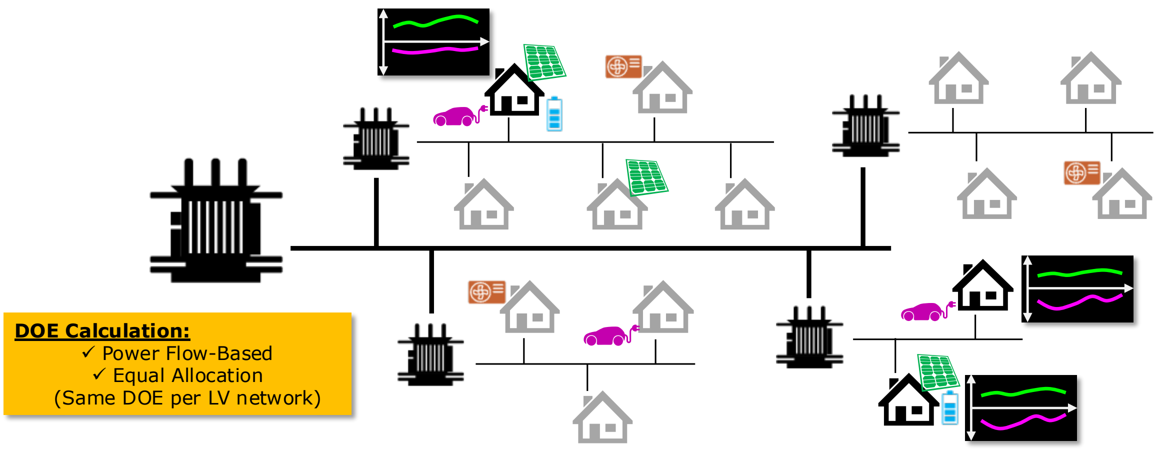

Figure 6 - DOE Implementation in MV-LV Distribution Networks

The following assumptions were made for the adoption rate of export and import DOEs:

- Export DOEs (including upgrades to 10 kVA PV systems and inverters)
  - 2028: Applies to new PV customers.
  - 2033: Applies to 50% of existing PV customers.
  - 2038: Applies to 100% of existing PV customers.
- Import DOEs
  - 2033: Applies to new EV customers.
  - 2038: Applies to 100% of existing EV customers.

3.1.4 Power Flow Simulations

Time series three-phase power flows were conducted at every 30 minutes for the three representing days and the seven analysis years, for the two scenarios of with and without DOEs. The following assumptions were made in power flow simulations for the integrated MV/LV networks:

- DER allocations were randomised, as were the residential customer profiles selected from a large pool of smart meter data. For 2023, it is assumed that 30% of residential customers already have their heating device electrified and 50% of them having their cooling devices electrified. The adoption of electrified heating, cooling, and hot water is assumed to reach 100% by 2053
- PV generation profiles are assumed to follow clear-sky irradiance conditions (i.e., no clouds)
- The voltage at the head of the MV feeder (i.e., secondary bus of the zone substation) was assumed to remain constant at 1 per unit (pu)
- MV and LV networks are assumed to be unchanged for the whole period of analysis from 2023 to 2053.

The following assumptions were made in power flow simulations for the sub-transmission networks:

- Time-series power flows were run using the sub-transmission network model, the adjusted ZSS demand profiles and the profiles of non-ZSS loads and generators directly connected to the sub-transmission network
- The voltage at either the 220kV or 66kV side of the terminal station transformer was assumed to remain constant (e.g.1.02 pu)
- Sub-transmission networks are assumed to be unchanged for the whole period of analysis from 2023 to 2053.

3.1.5 Voltage Management During Power Flow Simulations

As voltage non-compliance is a key impact arising from increased penetration of CER/DER, the research projects have taken additional steps in modelling voltage management. While the research projects use the network models developed in WP 1.4, significant improvement has been implemented in how voltage was managed to better reflect current DNSP practice and explore the full potential of voltage regulating devices.

The following principles were followed in the operation of voltage regulation devices:

- **Prioritizing local voltage solutions:** Voltage regulation devices operated in a sequence that prioritized the most localized solutions before broader network-wide solutions. This approach minimized the number of customers affected by network operations. In this study, the priority sequence was as follows: off-load tap changer (at the distribution transformer) → line capacitor banks (at the end of the MV feeder) → line voltage regulators (at the middle of the MV feeder) → on-load tap changer (at the zone substation, i.e., the head of the MV feeder).
- **Ensuring equal voltage headroom and footroom:** With the increasing adoption of various technologies, both voltage rise (caused by net export) and voltage drop (caused by net import) issues could occur in LV networks. To address both voltage issues, this approach aimed to maintain the median customer voltage (among all residential customers within the same MV-LV network) at 1.02 pu, which was the midpoint of the compliance range (i.e., 0.94 pu to 1.1 pu). By doing so, equal voltage headroom and footroom can be ensured across the entire MV-LV network. Note that this calculation assumed that voltage measurements from residential customers (i.e. from smart meters) were available in real-time.
- **Selecting the closest tap position to achieve the voltage target:** To model the discrete control nature of voltage regulation devices (i.e., tap adjustments), the closest tap position that brought the voltage within the compliance range was selected. For example, if the voltage target was calculated as 0.99 pu, the closest available tap at 1.0 pu was chosen.

Compared to online voltage regulation devices (i.e., OLTC, line voltage regulators, and line capacitor banks), whose settings varied throughout the day, the settings of off-load tap changers were relatively fixed for medium-term operation (e.g., from several months to years). To model the "offline" operation of off-load tap changers, the simulations were carried out in two runs to arrive at the optimal off-LTC setting for each distribution transformer (Figure 7). In association with online voltage regulation devices which operated in real-time, the voltage profiles for all the customers in the same MV-LV network were determined (Figure 8).

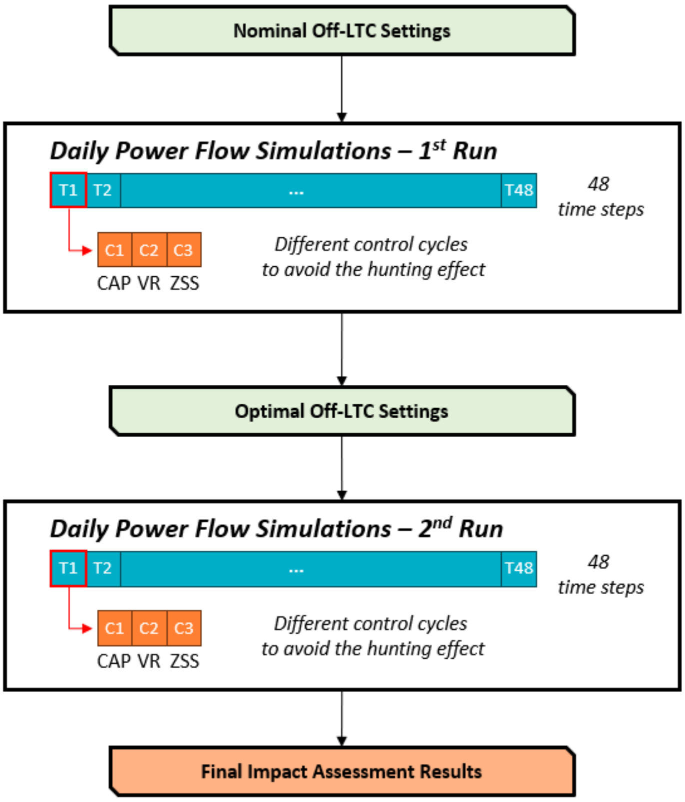

Figure 7 - Steps to Operationalise Voltage Regulation Devices

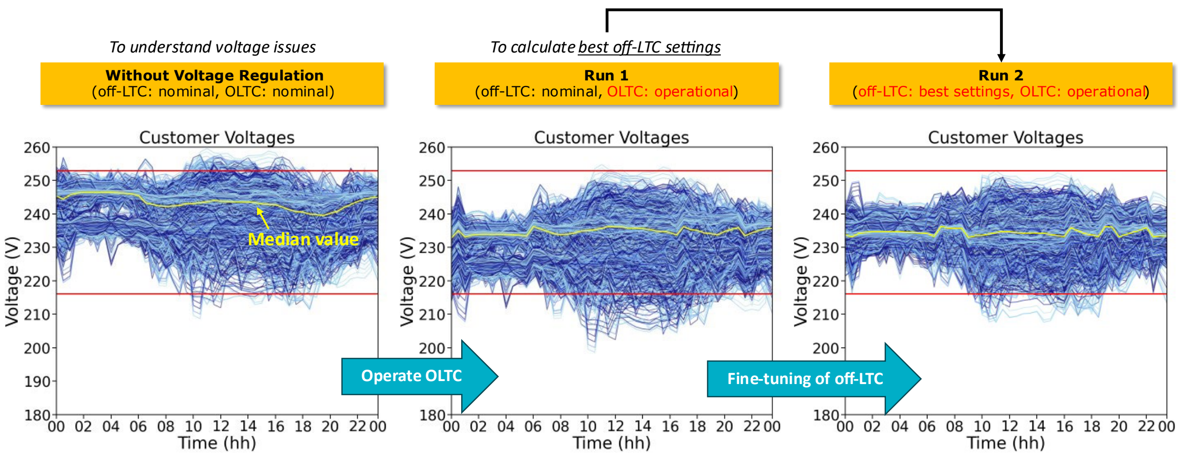

Figure 8 - Examples of Voltage Profiles with Voltage Regulation

The proposed voltage regulation scheme attempted to explore fully the potential of voltage regulating devices to improve customer voltage as much as possible. If voltage issues persisted in this ideal case, it indicated that other network and non-network solutions should be considered to further address the voltage issues.

3.1.6 Assessing Compliance from Power Flow Simulations

The following metrics are derived from power flow simulation results (i.e., voltages, currents, and power) to assess various aspects, including voltage assessment, thermal assessment, PV curtailment, and EV management.

Metrics - Overview

- **Maximum Absolute Power Flow (MVA):** The highest absolute power flow observed among the three representing days (i.e., spring shoulder day, summer peak day, and winter peak day).
- **Increase of Maximum Absolute Power Flow (%):** The percentage increase in maximum power flow compared to the previous analysis year.

Metrics - Voltage Assessment

Sub-Transmission Network

The voltage in pu (pu is the ratio of the voltage to the rated voltage e.g. one pu on a 66kV voltage level means a voltage of 66kV, one pu on a 220kV voltage level means a voltage of 220kV and so on) for every bus of the sub-transmission network. The main voltage levels considered are of 220kV, 66kV, and 22kV, depending on the sub-transmission network being studied.

For 220kV and 66kV areas:

- *Good*: between 0.9 pu and 1.1 pu
- *Concerning*: below 0.9 pu or above 1.1 pu

For 22kV and 6.6kV areas:

- *Good*: between 0.94 pu and 1.06 pu
- *Concerning*: below 0.94 pu or above 1.06 pu

For areas below 1kV:

- *Good*: between 0.94 pu and 1.1 pu
- *Concerning*: below 0.94 pu or above 1.1 pu

MV/LV Network

- Voltage Rise/Drop Non-Compliance Rate (%):
- The percentage of residential customers in the entire MV-LV network experiencing voltage rise issues (i.e., above 253V, 1.1 pu) or voltage drop issues (i.e., below 216V, 0.94 pu).
- **Maximum/Minimum Customer Voltage (V):** The highest and lowest residential customer voltage observed across the MV-LV network.
- **Ratio of LV Networks with Voltage Rise/Drop/Rise&Drop Issues (%):** The percentage of LV networks (associated with each distribution transformer) that have residential customers experiencing voltage rise issues, voltage drop issues, or both.

<u>Metrics - Thermal Assessment</u>

HV Transformer (terminal station transformer or ZSS transformer)

Utilisation of HV transformer is defined as the total apparent power (MVA) passing through the transformer divided by its rated capacity. This is done for every transformer of the sub-transmission network, considering ZSSs and terminal stations (when data is available). The following criteria is used to classify the different loading conditions:

- *Ideal load*: below 100%
- *Acceptable overload*: between 100% and 110%
- *Significant overload*: between 110% and 150%
- *Extreme overload*: above 150%

Sub-Transmission Line

Utilisation of sub-transmission line is defined as the total apparent power (MVA) passing through the line divided by its rated capacity. This is done for every line (when data is available) of the sub-transmission network. The following criteria is used to classify the different loading conditions:

- *Ideal load*: below 100%
- *Acceptable overload*: between 100% and 110%
- *Significant overload*: between 110% and 150%
- *Extreme overload*: above 150%

MV Feeder

- **Overloaded Conductor Length (km):** The total length of overloaded MV conductors (i.e., utilisation above 100% for any time step). Utilisation is defined as the ratio of maximum demand to ampacity ratings.
- **Max. Utilisation of the Worst Performing MV Segment (%):** The highest utilisation percentage (based on ampacity ratings) among all MV conductor segments.

Distribution Transformer

- **Ratio of Distribution Transformer with Max. Utilisation within Each Range:** The percentage of distribution transformers with their peak one-time-step utilisation falling within different ranges (i.e., ≤100%, 100-110%, 110-150%, and >150%).
- **Avg. Overloading Duration (hr):** The average number of hours that distribution transformers remain overloaded within each utilisation range.
- **Max. Utilisation of the Worst Performing Transformer (%):** The highest utilisation percentage (based on kVA rating) among all distribution transformers.

LV Circuit

- **Ratio of LV Circuit with Max. Utilisation within Each Range**: The percentage of LV circuits with their peak one-time-step utilisation falling within different ranges (i.e., ≤100%, 100-110%, 110-150%, and >150%).
- **Max. Utilisation of the Worst Performing LV Circuit (%):** The highest utilisation percentage (based on ampacity ratings) among all LV circuits.

Metrics - PV Curtailment Assessment

Per Customer

- **Max. PV Curtailment (kWh):** The highest PV curtailment observed for any customer with a PV system in the MV-LV network.
- **Ratio of Max. PV Curtailment (%):** The highest percentage of total PV curtailment relative to total PV generation, per PV customer. Annual PV generation is calculated considering a combination of 30 summer peak days, 30 winter peak days and 305 shoulder days.
- **Ratio of PV Customers Curtailed (%):** he percentage of PV customers experiencing curtailment in the MV-LV network.

Aggregate Export

- **PV Curtailment (MWh):** The total PV curtailment across the entire MV-LV network.
- **Ratio of PV Curtailment (%):** The percentage of total PV curtailment relative to total PV generation in the MV-LV network.

Metrics - EV management Assessment *(Applicable to the "With DOEs" Scenario Only)*

- **Ratio of EVs Affected (%):** The percentage of EVs subject to charging management via import DOEs (i.e., charging demand is reduced).
- **Avg. EV Charging Delay (hrs):** The average charging delay for affected EVs across the MV-LV network.

The various metrics are summarised in impact tables. Colour coding is used to indicate the relative seriousness of the impact.

3.1.7 Impact Assessment (Without DOEs) – Selected Sub-Transmission Networks

Impact tables are provided in WP 1.6 research report, incorporating metrics from the power flow simulations on the selected sub-transmission network and metrics of the associated MV/LV networks. Metrics of the associated MV/LV networks are based on extrapolation of the power flow simulation results from WP 1.5. An example of the impact table for CBTS sub-transmission network is shown in Table 5. Impact tables for other sub-transmission networks can be found in Appendix Three of this summary report.

Sub-transmission Network – CBTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			483	543	625	732	861	1027	1145
Increase of Max. Demand at Terminal Station (MVA)			-	12%	15%	17%	18%	19%	11%
Power Factor at Terminal Station for Max. Demand			0.98	0.98	0.96	0.94	0.91	0.85	0.8
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	37%	42%	63%
Maximum Voltage (pu)			1.06	1.06	1.06	1.06	1.06	1.06	1.06
Minimum Voltage (pu)			0.97	0.96	0.93	0.90	0.84	0.75	0.67
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	83%	75%	8%	8%	8%	8%	8%
		100%-110%	17%	8%	50%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	1.5	5	2.2	0	0	0	0
		110%-150%	0%	17%	42%	58%	42%	0%	0%
		Avg. Overloading Duration (hr)	0	2.5	5.5	5.9	9.7	0	0
		> 150%	0%	0%	0%	33%	50%	92%	92%
		Avg. Overloading Duration (hr)	0	0	0	2.6	6.2	8.4	10.7
	Max. Utilisation of the Worst Performing Transformer		106%	119%	138%	158%	195%	219%	228%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	85%	77%	38%	38%	38%
		100%-110%	0%	0%	0%	0%	15%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	1.8	0	0
		110%-150%	0%	0%	15%	23%	31%	31%	0%
		Avg. Overloading Duration (hr)	0	0	3.3	7.2	4.9	6.6	0
		> 150%	0%	0%	0%	0%	15%	31%	62%
		Avg. Overloading Duration (hr)	0	0	0	0	7	9.8	8.6
	Max. Utilisation of the Worst Performing Line		82%	98%	119%	148%	187%	245%	280%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	2%	6%	9%	12%	14%	18%
Residential Voltage Drop Non-Compliance			2%	5.3%	10%	14%	18%	23%	27%
% of LV Networks with Voltage Rise Issues			1%	9%	15%	18%	19%	21%	22%
% of LV Networks with Voltage Drop Issues			9%	17%	20%	23%	28%	33%	39%
% of LV Networks with Both Voltage Rise & Drop Issues			1%	9%	15%	18%	19%	21%	22%
MV-LV Thermal Assessment (extrapolation of metrics)									

% of Distribution Transformers with Maximum Utilisation	**<= 100%**	100%	97%	86%	75%	70%	64%	62%
	100%-110%	0.1%	2%	5%	4%	3%	3%	2%
	110%-150%	0.3%	0.5%	8%	16%	14%	10%	10%
	> 150%	0%	0.3%	0.8%	5%	14%	23%	26%
PV Curtailment Assessment (extrapolation of metrics)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	**Total PV Curtailment (GWh)**	15	29	45	70	86	114	142
	% of PV Curtailment	6%	9%	12%	15%	18%	21%	24%

Table 5 - Impact assessment for the CBTS sub-transmission network without DOEs

In summary, terminal stations are expected to face severe overloading issues between 2033 and 2048, with 2033 peak utilization rates of 119-146% and overutilization periods of 8-14 hours during peak demand days. ERTS and TTS are the earliest to face significant overloading by 2033, reaching 133% and 146% utilization respectively. By 2053, the situation worsens across all networks selected for power flow simulations, with overloading reaching 131-345% and overutilization periods extending to 14-24 hours. ERTS and TTS show the most severe projections, potentially exceeding 340% utilization, while GNTS shows the least severe overloading at 131% by 2053, though still critical.

Sub-transmission networks are expected to face varying degrees of undervoltage issues projected to occur between 2033 and 2048, with TSTS being the only exception, showing no voltage issues throughout the assessment period (2023-2053). The percentage of affected buses ranges from 7% in GNTS-MBTS by 2033 to 39% in SMTS by 2038. These undervoltage problems primarily affect the 66kV networks, but some 22kV networks (secondary of ZSSs) are also impacted, indicating that OLTCs at both terminal stations and ZSSs, as well as capacitor banks, have reached their operational limits in maintaining voltage levels. The issues generally occur during early morning and peak periods (morning and evening) of the worst day (winter peak), attributed to high loading conditions caused by electrified heating systems, increased adoption of cooling systems, and rising EV usage by residential customers.

ZSS transformers across all sub-transmission networks are expected to face escalating overloading issues. ERTS, SMTS, and TTS encounter concerning problems by 2033, CBTS and GNTS-MBTS by 2038, and TSTS by 2048. By 2053, overloading becomes critical, with 36% (GNTS-MBTS) to 100% (TTS) of transformers exceeding 150% utilization. Peak rates reach up to 441% (SMTS), with some networks experiencing overloads for an average of 11 hours during peak demand days.

Sub-transmission lines are expected to face varying degrees of overloading issues between 2038 and 2053. Four networks (CBTS, ERTS, SMTS, and TTS) face significant challenges, while GNTS-MBTS and TSTS are expected to remain without issues throughout the assessment period (2023-2053). By 2038, the affected networks show 10-23% of lines experiencing significant overload (110-150%) for 5-

7 hours on average, with some lines in TTS already facing extreme overload (>150%). The situation worsens by 2053, with CBTS experiencing the most severe issues (62% of lines exceeding 150% utilization for over 8 hours), followed by TTS (40% of lines exceeding 150%). Peak utilization rates reach up to 241% in ERTS and 244% in TTS.

3.1.8 Impact Assessment (Without DOEs) – MV/LV Networks for the Whole State of Victoria

The following impact table for MV/LV networks across the state of Victoria is provided in WP 1.6 research report, based on extrapolation of the power flow simulation results of the four MV/LV networks from WP 1.5. Note that as CBD network type is not included in the analysis, not all the ZSS are included in the impact table.

Whole-State (211 ZSS out of 246) (without DOEs)								
Year		2023	2028	2033	2038	2043	2048	2053
Voltage Assessment								
Residential Voltage Rise Non-Compliance	All ZSS	0.2%	1%	4%	6%	10%	12%	16%
	<50 MVA	0.2%	2%	4%	7%	10%	13%	18%
	50-100 MVA	0.2%	2%	4%	7%	10%	12%	16%
	>100 MVA	0.1%	1%	3%	5%	8%	11%	13%
Residential Voltage Drop Non-Compliance	All ZSS	2%	4%	9%	13%	18%	22%	26%
	<50 MVA	2%	4%	9%	13%	17%	21%	27%
	50-100 MVA	2%	4%	9%	13%	18%	22%	26%
	>100 MVA	1%	3%	9%	14%	18%	23%	25%
% of LV Networks with Voltage Rise Issues	All ZSS	0.7%	8%	13%	15%	16%	18%	21%
	<50 MVA	0.6%	5%	9%	10%	11%	13%	18%
	50-100 MVA	0.7%	9%	14%	16%	18%	20%	22%
	>100 MVA	0.8%	11%	18%	21%	23%	26%	28%
% of LV Networks with Voltage Drop Issues	All ZSS	8%	14%	17%	20%	23%	28%	36%
	<50 MVA	5%	10%	12%	14%	17%	21%	31%
	50-100 MVA	9%	15%	18%	21%	25%	30%	37%
	>100 MVA	11%	20%	23%	26%	31%	38%	45%
% of LV Networks with Both Voltage Rise & Drop Issues	All ZSS	0.7%	8%	13%	15%	16%	18%	20%
	<50 MVA	0.6%	5%	9%	10%	11%	12%	16%
	50-100 MVA	0.7%	9%	14%	16%	17%	19%	21%
	>100 MVA	1%	13%	22%	26%	27%	30%	31%
Thermal Assessment								

% of Distribution Transformers with Maximum Utilisation	<= 100%	All ZSS	99%	96%	86%	76%	70%	64%	62%
		<50 MVA	99%	96%	89%	81%	76%	70%	67%
		50-100 MVA	99%	96%	86%	75%	69%	63%	62%
		>100 MVA	100%	96%	76%	58%	51%	46%	45%
	100%-110%	All ZSS	0.4%	2%	5%	4%	3%	3%	3%
		<50 MVA	1%	1%	3%	3%	3%	3%	3%
		50-100 MVA	0.4%	2%	5%	4%	3%	3%	2%
		>100 MVA	0.2%	4%	9%	5%	4%	4%	2%
	110%-150%	All ZSS	0.5%	1%	8%	15%	13%	11%	11%
		<50 MVA	0.6%	2%	6%	10%	10%	11%	11%
		50-100 MVA	0.4%	1%	8%	16%	13%	11%	11%
		>100 MVA	0.1%	0.5%	15%	29%	22%	12%	12%
	> 150%	All ZSS	0%	0.5%	2%	6%	14%	22%	25%
		<50 MVA	0%	0.7%	2%	6%	11%	17%	19%
		50-100 MVA	0%	0.4%	1%	6%	14%	23%	25%
		>100 MVA	0%	0.1%	0.5%	8%	23%	38%	42%
PV Curtailment									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		410	793	1218	1733	2353	3123	3878
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	24%

Table 6 - Impact assessment for the MV/LV networks across the whole state of Victoria, without DOEs

In the next decade (starting from 2023), PV penetration is expected to grow steadily, and voltage issues can emerge as a limiting factor for further PV uptake. Typically for those ZSS with MV-LV networks less robust to voltage changes.

From 2033, the PV uptake slows down and net demand rises significantly due to the presence of increasing EV adoption and residential electrification (i.e., heating/cooling and hot water systems), which further exacerbate voltage issues. Note that since the voltage regulation devices in this study are operated to ensure equal voltage headroom and footroom, more voltage drop issues have emerged as a result of managing PV-related voltage rise issues. This indicates that voltage regulation devices (i.e., tap positions) have been exhausted to maintain customer voltages within both upper and lower limits.

By 2028, about 4% (~6,800, out of the estimated 170, 000) of state distribution transformers are expected to experience overloading, escalating to 14% (~23,800) by 2033, and 24% (~40,800) by 2038. This rapid increase in overloaded transformers could severely limit further DER uptake without network augmentation.

PV curtailment increases from 410 GWh (6%) in 2023 to 3,878 GWh (24%) in 2053 as PV penetration grows from 27% to 47%. This curtailment is mainly due to 5 kVA inverter capacity limits and Volt-Watt function constraints, limiting renewable energy penetration across MV-LV networks.

3.1.9 Impact Assessment (With DOEs) – Selected Sub-Transmission Networks

Impact tables are provided in WP 1.6 research report, incorporating metrics from the power flow simulations on the selected sub-transmission network and metrics of the associated MV/LV networks. Metrics of the associated MV/LV networks are based on extrapolation of the power flow simulation results from WP1.5. An example of the impact table for CBTS sub-transmission network is shown in Table 7. Impact tables for other sub-transmission networks can be found in Appendix Four of this summary report.

Sub-transmission Network – CBTS (With DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			483	543	620	721	836	970	1078
Increase of Max. Demand at Terminal Station (MVA)			-	12%	14%	16%	16%	16%	11%
Power Factor at Terminal Station for Max. Demand			0.98	0.98	0.96	0.94	0.90	0.86	0.83
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	37%	42%	47%
Maximum Voltage (pu)			1.06	1.06	1.06	1.06	1.06	1.06	1.06
Minimum Voltage (pu)			0.97	0.96	0.93	0.90	0.84	0.78	0.70
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	83%	75%	33%	8%	8%	8%	8%
		100%-110%	17%	8%	33%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	1.5	5	4.5	0	0	0	0
		110%-150%	0%	17%	33%	75%	50%	33%	0%
		Avg. Overloading Duration (hr)	0	2.5	6.8	7.7	10.3	14.5	0
		> 150%	0%	0%	0%	17%	42%	58%	92%
		Avg. Overloading Duration (hr)	0	0	0	2	6.3	8.8	8.6
	Max. Utilisation of the Worst Performing Transformer		106%	119%	136%	155%	187%	218%	218%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	85%	77%	46%	38%	38%
		100%-110%	0%	0%	0%	0%	8%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0.5	0	0
		110%-150%	0%	0%	15%	23%	31%	38%	15%
		Avg. Overloading Duration (hr)	0	0	3	6.3	2.8	5.9	7.3
		> 150%	0%	0%	0%	0%	15%	23%	46%

		Avg. Overloading Duration (hr)	0	0	0	0	6	10.5	7.4
	Max. Utilisation of the Worst Performing Line		82%	98%	118%	146%	180%	228%	259%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.3%	2%	4%	7%	8%	8%	10%
Residential Voltage Drop Non-Compliance			2%	5.1%	8%	12%	15%	20%	25%
% of LV Networks with Voltage Rise Issues			0.8%	8%	13%	14%	13%	15%	16%
% of LV Networks with Voltage Drop Issues			9%	16%	19%	22%	25%	30%	34%
% of LV Networks with Both Voltage Rise & Drop Issues			0.8%	8%	13%	13%	13%	14%	15%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	97%	89%	76%	73%	68%	65%
		100%-110%	0.1%	2%	3%	5%	3%	4%	4%
		110%-150%	0.3%	0.5%	8%	16%	15%	11%	10%
		> 150%	0%	0.3%	0.7%	3%	10%	17%	21%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		23	38	74	150	198	255	304
	% of PV Curtailment		6%	8%	13%	24%	28%	31%	34%
EV Management Assessment (extrapolation of metrics)									
% of EVs Affected			-	-	9%	12%	16%	20%	24%
Average EV Charging Delay (h)			-	-	3.3	4.9	5	4.9	4.8

Table 7 - Impact assessment for the CBTS sub-transmission network with DOEs

In summary, the adoption of import DOEs by residential customers consistently reduces load across all terminal stations, with impacts ranging from less than 1% in 2023 to 14% by 2053. ERTS shows the most significant reduction (14%, 318 MVA) by 2053. However, despite these reductions, all seven terminal stations continue to exceed their thermal limits in the same years as in the scenario without DOEs. TSTS experiences a brief respite in 2033, with load reduction bringing it within thermal capacity (531 MVA) and potentially delaying upgrades by 5 years, but this benefit is short-lived. While import DOEs provide some load relief, they are insufficient to resolve the long-term thermal capacity issues or significantly delay the need for upgrades at these terminal stations.

The adoption of import DOEs by residential customers generally results in slight improvements to sub-transmission voltages, with effects becoming noticeable between 2038 and 2053, depending on the network. However, these improvements are largely insufficient to bring voltages within statutory limits for most networks, when compared to the scenario without DOEs. The TTS sub-transmission network stands out as an exception, where the small voltage improvement in 2038 is enough to eliminate voltage issues for that year, potentially delaying necessary upgrades by 5 years.

Nevertheless, even for TTS, the improvements are not sufficient to maintain voltages within statutory limits after 2043.

The adoption of import DOEs by residential customers across all seven sub-transmission networks results in slight loading reductions on ZSS transformers, observed from as early as 2028 in GNTS-MBTS to 2038 in TSTS. These reductions decrease both the intensity and duration of overloads, but upgrades remain necessary for all networks as the number of overutilized transformers has not significantly decreased, and capacity issues persist.

The adoption of import DOEs by residential customers reduces the intensity and duration of sub-transmission line overloads in CBTS, ERTS, SMTS, and TTS networks from 2033-2038. However, while providing some relief, these reductions are insufficient to eliminate the need for network upgrades as capacity issues persist.

3.1.10 Impact Assessment (With DOEs) – MV/LV Networks for the Whole State of Victoria

The following impact table for MV/LV networks across the state of Victoria is provided in WP 1.6 research report, based on extrapolation of the power flow simulation results of the four MV/LV networks from WP 1.5. Note that as CBD network type is not included in the analysis, not all the ZSS are included in the impact table.

Whole-State (211 ZSS out of 246) (with DOEs)								
Year		2023	2028	2033	2038	2043	2048	2053
Voltage Assessment								
Residential Voltage Rise Non-Compliance	All ZSS	0.2%	1%	3%	4%	5.1%	6%	7%
	<50 MVA	0.2%	1%	3%	5.1%	6%	6%	10%
	50-100 MVA	0.2%	1%	3%	5%	5.4%	6%	7%
	>100 MVA	0.1%	0.9%	2%	3%	4%	5%	3%
Residential Voltage Drop Non-Compliance	All ZSS	2%	4%	7%	11%	14%	19%	24%
	<50 MVA	2%	4%	7%	11%	14%	19%	25%
	50-100 MVA	2%	4%	7%	11%	14%	19%	24%
	>100 MVA	1%	3%	7%	11%	15%	20%	23%
% of LV Networks with Voltage Rise Issues	All ZSS	0.7%	7%	11%	11%	11%	13%	15%
	<50 MVA	0.6%	5%	7%	8%	7%	9%	14%
	50-100 MVA	0.7%	8%	12%	12%	11%	13%	16%
	>100 MVA	0.8%	10%	15%	16%	14%	17%	19%

% of LV Networks with Voltage Drop Issues		All ZSS	8%	14%	16%	18%	21%	25%	32%
		<50 MVA	5%	9%	11%	13%	16%	20%	29%
		50-100 MVA	9%	15%	17%	19%	23%	27%	33%
		>100 MVA	11%	19%	23%	24%	29%	30%	38%
% of LV Networks with Both Voltage Rise & Drop Issues		All ZSS	0.7%	7%	11%	11%	11%	12%	14%
		<50 MVA	0.6%	5%	7%	8%	7%	8%	12%
		50-100 MVA	0.7%	7%	12%	12%	11%	13%	15%
		>100 MVA	1%	11%	18%	19%	17%	19%	20%
Thermal Assessment									
% of Distribution Transformers with Maximum Utilisation	<= 100%	All ZSS	99%	96%	89%	77%	73%	69%	66%
		<50 MVA	99%	96%	91%	83%	80%	75%	72%
		50-100 MVA	99%	96%	88%	76%	73%	68%	65%
		>100 MVA	100%	96%	81%	59%	54%	50%	46%
	100%-110%	All ZSS	0.4%	2%	3%	5%	3%	4%	4%
		<50 MVA	0.7%	1%	2%	4%	2%	4%	4%
		50-100 MVA	0.4%	2%	3%	5%	3%	4%	4%
		>100 MVA	0.2%	3%	5%	9%	4%	5%	4%
	110%-150%	All ZSS	0.5%	1%	7%	14%	14%	11%	11%
		<50 MVA	0.6%	2%	5%	9%	10%	9%	10%
		50-100 MVA	0.4%	1%	8%	15%	14%	11%	11%
		>100 MVA	0.1%	0.5%	14%	28%	25%	16%	14%
	> 150%	All ZSS	0%	0.5%	1%	4%	10%	16%	20%
		<50 MVA	0%	0.7%	2%	4%	8%	12%	14%
		50-100 MVA	0%	0.4%	1%	4%	10%	17%	20%
		>100 MVA	0%	0.1%	0.5%	4%	17%	30%	35%
PV Curtailment									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		581	983	1865	3656	4974	6600	7872
	% of PV Curtailment		6%	8%	13%	22%	27%	32%	34%
EV Management									
Percentage of EVs Affected			-	-	9%	13%	16%	20%	24%
Average EV Charging Delay (h)			-	-	3.5	5	5.3	5.2	5.1

Table 8 - Impact assessment for the MV/LV networks across the whole state of Victoria, with DOEs

In summary, the adoption of export DOEs by residential customers effectively mitigate voltage rise issues caused by PV export once applied to all residential PV customers (by 2038). However, since PV inverters functions (i.e., Volt-Watt and Volt-Var) already enforce PV curtailment to help regulate voltages in the scenario without DOEs, the additional benefits of export DOEs may be limited.

Since import DOEs are applied by the researchers only to Level-2 EV charging, only a small fraction of the demand is managed (up to 30%). Over time, the demand from residential electrification (i.e., heating/cooling and hot water systems) becomes significant, resulting in more voltage drops and heavy asset utilisation. Consequently, managing Level-2 EV demand alone is insufficient to resolve both voltage and thermal issues.

The adoption of import DOEs by residential customers shows positive impacts on thermal performance of distribution transformer from 2033 onwards. The number of overloaded transformers decreases by 1% (~1,700) to 5% (~8,500) annually between 2033 and 2053, with 2% (~3,400) to 5% (~8,500) fewer transformers experiencing extreme overloading (>150%). These improvements will significantly reduce required network augmentation investments across the state.

Initially export DOEs reduce PV curtailment slightly (8% or 983 GWh in 2028, compared to 9% or 793 GWh without DOEs). However, as export DOE adoption increases, curtailment surpasses the without-DOEs scenario due to additional constraints and the "Equal Allocation" strategy. By 2033, curtailment reaches 1,865 GWh (13%), and by 2053, it reaches 7,872 GWh (34%). Note that PV inverters are upgraded to 10 kVA in the DOEs scenario, unlocking greater PV potential but also increasing curtailment.

With residential customers adopting import DOEs for Level-2 EVs from 2033, Victorian residential customers should expect some EV charging delays. Analysis shows these delays are under 6 hours throughout the study period for the four MV/LV network types considered. Nevertheless, these delays primarily occur overnight, minimizing disruptions for EV users. It is worth noting that the application of DOEs is informative more broadly of an instrument to physically limit supply/export. Whether such an instrument need be mandated, opt in, the degree to which it can be over-ridden, the commercial incentive shared with consumers and so on will depend on the level of consumer acceptance and balancing alternate options.

3.2 Inclusions, exemptions and limitations

WP 1.5 and WP 1.6 were set an ambitious goal to quantify the long-term impact of increasing CER/DER on the Victorian distribution networks covering the sub-transmission, HV, MV and LV networks. The research projects utilise the bottom-up models developed by other research projects in work package one, specifically the electrified heating/cooling profiles and domestic hot water models from WP 1.1, and the sub-transmission and MV/LV network models from WP 1.4.

To contain the tasks within the limited timeframe of the research projects, some simplified design characteristics are incorporated that have inherent limitations. Detailed lists of consideration and assumptions can be found in the research reports[10, 11]. A summary of the key limitations is provided below:

- Network augmentation or planned connections/expansions are not considered in this study, i.e. distribution networks (sub-transmission, HV, MV and LV) are assumed to remain unchanged throughout the assessment period (2023-2053).
- Only peak demand days (winter and summer) and shoulder days are considered in the impact assessment, while minimum demand days are out of scope.
- Annual PV generation is calculated considering a combination of 30 summer peak days, 30 winter peak days and 305 shoulder days.
- The effect of energy efficiency on residential demand is not considered (i.e. the same residential profiles apply to the 30-year analysis period).
- Commercial and Industrial (C&I) customers are assumed to have the same type of profiles, with load operated for 24 hours and higher during the daytime (i.e., 9am-5pm)
- For 2023, it is assumed that 30% of residential customers already have their heating device electrified and 50% of them having their cooling devices electrified.
- Only MV feeder types considered are Urban, Suburban, Rural-Short and Rural-Long. The CBD MV feeder type is not considered. This means that in the whole-state extrapolation any zone substation containing CBD MV feeder type was excluded from the impact assessment.
- For zone substations containing urban MV feeder type, it was assumed that half of these feeders are urban, while the other half are suburban.
- For zone substations containing rural MV feeder type, it was assumed that half of these feeders are short rural, while the other half are long rural.
- Single-wire earth return (SWER) networks are not modelled or considered in rural feeders.
- All LV conductors assume to adopt the modern design (i.e. lower impedance and larger ampacity).
- The voltage at the terminal station is assumed to be fixed to a certain value (depending on the station) at either the 220kV or 66kV side.
- For MV/LV power flow simulations, the voltage at the head of the MV feeder (i.e., secondary bus of the zone substation) is assumed to remain constant at 1 pu.
- No battery storage is assumed in this study.

Due to these simplifying assumptions, the impact assessment should be viewed as illustrative rather than definitive.

[10] WP 1.5 Integrated MV-LV Network Studies to Assess Electrification Impact: Final Report, List of Considerations and Assumptions, page 10
[11] WP 1.6 Whole-State Network Impact Assessment: Final Report, List of Considerations and Assumptions, page 10

4. Observations, insights and key reflections for stakeholders

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

4.1 DNSPs

The simulation outcomes show significant increase in incidences of asset overloading and voltage non-compliance across the whole distribution network from terminal station supply points to distribution substations as Victoria goes through the electrification journey from 2023 to 2053, under a do-nothing investment scenario using forecast uptake of solar PV, electric vehicles and gas electrification. From a consumer perspective, there are increasing constraints on the operation of their CERs, such as solar export curtailment and EV charging constraint. The impact on the distribution network poses significant challenge for the performance of existing and new connections of CERs/DERs and will limit their beneficial contribution to the electricity supply system.

Other research projects in the C4NET ESP have examined ways to reduce the network impact by investigating flexibility instruments (WP 2.7/2.8) and storage technologies (WP 2.9). The modelling carried out in WP 1.5/1.6 examine the use of DOEs as a mechanism to reduce the network impact. The beneficial effects of DOEs have been illustrated using power flow simulations for distribution network comprising selected Victorian sub-transmission and MV/LV networks.

Here are some insights from the simulations:

- Voltage management
    - Voltage rise phenomenon caused by solar export is the current concern for DNSPs. With increasing consumption coming from EV and gas electrification and non-coincidence of peak solar generation and load consumption patterns, DNSPs are going to face both voltage rise and volage drop challenges. The refined voltage management approach used in the power flow simulations demonstrates that attention to transformer tapping range, tap settings and voltage control settings could help to improve voltage management and therefore the capacity of the existing network to host more CER/DER. Actual implementation of advanced voltage management scheme has already occurred for some DNSPs e.g. the Dynamic Voltage Management System that adjusts zone substation voltage regulating setpoint based on near real-time analysis of smart meter voltage data.

- Power Quality Response Mode of solar PV inverters
    - The mandatory Volt/Var and Volt/Watt power quality response modes on solar PV inverters have been demonstrated to be effective in reducing the adverse impact (voltage rise) of excess solar export. One thing worth considering (but not covered in the power flow simulations) is to incentivise solar PV owners to provide reactive support during peak demand period when solar generation is in decline. The current Australian Standard AS/NZS 4777.2 -2020 does not require PV inverters to provide reactive power when the real power is less than 20% rated value.
- Distribution asset performance metrics – the research reports have used a number of performance metrics relating to asset utilisation, voltage compliance, PV curtailment and EV charging curtailment. These are by no means the only performance metrics that can be used. It is important to develop a set of performance metrics that are agreed to by all stakeholders.
- Export DOEs
    - Export DOEs have been demonstrated to be effective in managing voltage rise impact and should be rolled out as soon as practicable (noting that the approach in the allocation of available network capacity can be refined over time)
    - Export DOEs works in conjunction with mandatory inverter power quality response modes (Volt/Var and Volt/Watt) to further alleviate voltage rise issue.
- Import DOEs
    - Import DOEs have been demonstrated to be effective in reducing voltage drop and asset overload impact when applied to EV level 2 charging in the short term.
    - In the longer term, however, import DOEs would need to be applied to other flexible loads within a home to be effective.
    - Import DOEs are likely to carry risk to consumers in the consumption of an essential service where applied to other flexible loads. This should be factored into any consideration of introduction.
- While DOEs are useful, there is no one silver bullet and hence DNSPs should consider deploying other approaches such as flexibility instruments, network support services and energy storage.

Strategic planning and investment in long term infrastructure, combined with operational measures can lower the costs for all consumers. The regulatory and market frameworks however will need to be modernised if we want incentives for all actors to participate in a means that does so. The more harmonised and consistent the approach is across distribution areas the easier it will be for regulators and policy makers to respond, as well as streamline solutions for consumers. DNSPs may consider how they could support the development of such changes. The same could be said for working with AEMO to facilitate long term distribution considerations within a whole-of-system planning approach.

4.2 AEMO

AEMO's Integrated System Plan (ISP) includes forecast of highly coordinated CERs (CERs that are centrally coordinated through arrangements such as VPP) primarily for the benefits of the energy market. The simulations conducted indicate that significant network constraints will need to be overcome for the performance and connection of CERs especially if they are not coordinated to match the available network capacity. The sheer scale of the distribution network impact has been demonstrated through the simulations. The impact and the resulting significant investment can be mitigated by innovative approaches such as DOEs. To unlock the full potential of CER/DER will require close collaboration between AEMO and DNSPs as well as policy makers, researchers and consumers.

4.3 Policy makers

The project demonstrates the mammoth challenge faced by the electricity distribution industry to accommodate the forecast increase in the connection of CER/DER and the increased peak consumption from gas electrification.

Simulations have confirmed the beneficial effect of import and export DOEs, working alongside solar inverter power quality response modes, in alleviating the network impact. As CERs are owned by consumers, the willingness of consumers to accept limitations posed by DOEs depends on government policy and incentive framework.

Policy makers can play a significant role in introducing a range of mechanisms or incentives that improve customer acceptance of DOEs noting that adaptation needs to balance the value for both the individual and communal system benefits, in a manner that avoids complexity for households:

(1) Standards – import DOEs as applied to EV charging control will require standards to ensure EV charging equipment supports the use of DOEs
(2) Incentives to increase the type of flexible loads that can be coordinated:
    a. simulations demonstrate that import DOE applied to EV Level 2 charging alone is not sufficient in alleviating demand increase from other electrification processes
    b. there will need to be clear rules with regard to the responsibility for adhering to premise level DOE when multiple flexible BTM loads are being coordinated
    c. any considering of flexible imports would have to be guided by very clear roles and responsibilities, advice on which loads it can be applied to, explicit informed consent and consumer protections.
(3) Balance between mandatory and market mechanisms – DOE can be a form of mandatory mechanism whereas consumers generally favour a voluntary/market approach. A guiding principle could be that benefits should be shared with the asset owner (e.g. Consumer) first and mandatory mechanisms are only pursued where necessary.

(4) Allocation principle of DOEs – the project performed simulations of the effect of DOEs using the "equal allocation" principle whereby available network capacity is distributed equally to participating consumers. This approach does not result in optimal use of available network capacity because the DOE will be determined by the consumer in the worst location of the local network (generally at the end of a LV feeder).

(5) Awareness - raise awareness of consumers to the incentives/automation opportunities that are designed to reduce the overall costs to support the move to the acquisition of CER.

4.4 Consumer

EV consumers need to be aware of the challenges and opportunities created by their charging behaviour and be aware of the incentives (e.g. tariff structures that incentivise charging at solar soak times, rewards for providing network support services through V2G products, rewards for accepting a flexible import product) to support the behaviour that will ultimately benefit the electricity system and all energy consumers.

4.5 Research

A gap exists in the network models used for the simulations in that SWER networks have not been represented. It is important that consumers living in the rural areas are not left behind in the energy transformation journey. Hence a need to extend the network models to cover the SWER networks.

There is opportunity for the research communities to refine the modelling approach to come up with better representative network models. Any approach is recommended to have deep engagement and input from those with deep distribution network knowledge to ensure any modelled approach is as close to real-world as possible and is sufficiently developed to include the impact of using modern network management tools. As networks become increasingly dynamically managed it will be important to update modelling approaches to reflect this. Any model development requires timely and complete data to develop. Researchers can facilitate this through the use of consistent nomenclature and well-considered complete data specifications upfront that are co-developed with the respective network champion who can facilitate the delivery of such data.

Appendix One

Researcher profile

Conducted by: University of Melbourne, Melbourne

	WP 1.5	WP 1.6
Lead Researcher:	Jing Zhu	Dr Arthur G. Givisiez
Research Team:	Dr Arthur G. Givisiez, Andres Avila Rojas	Prof Luis (Nando) Ochoa

About C4NET

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

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

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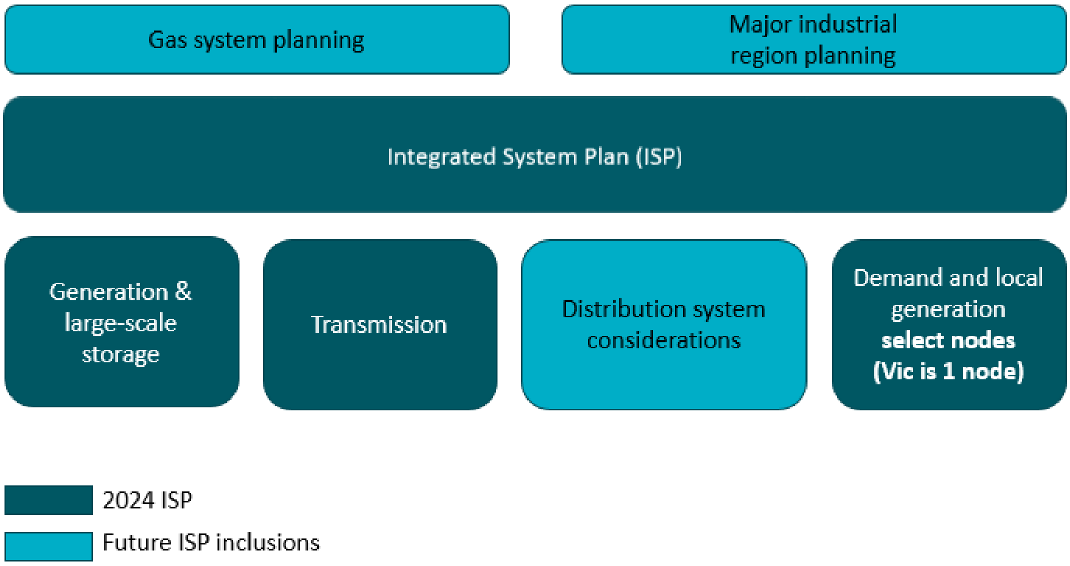
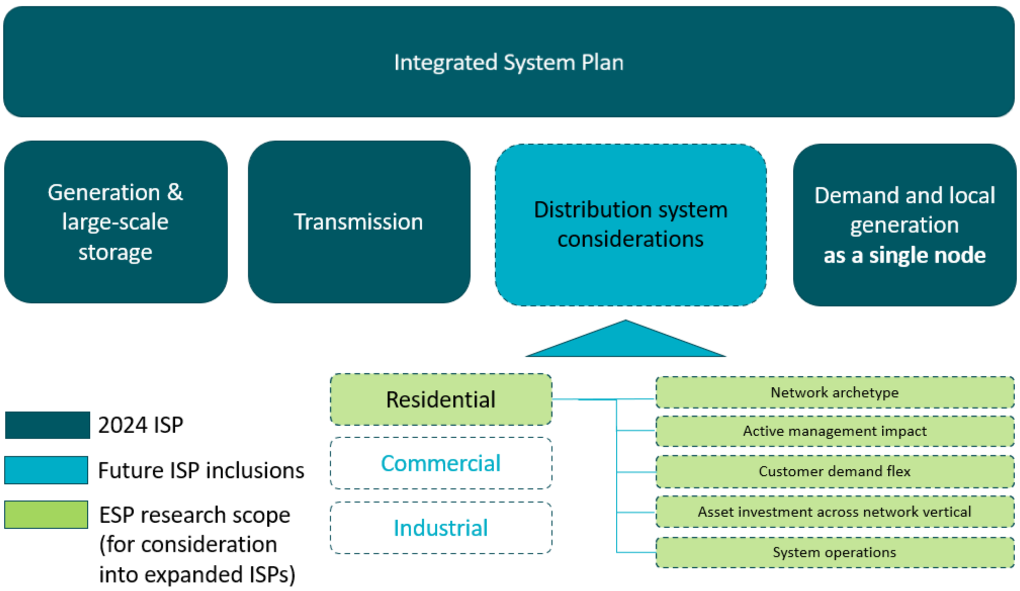
Appendix Two – Bigger picture integration with the ISP

Shift towards whole of system planning



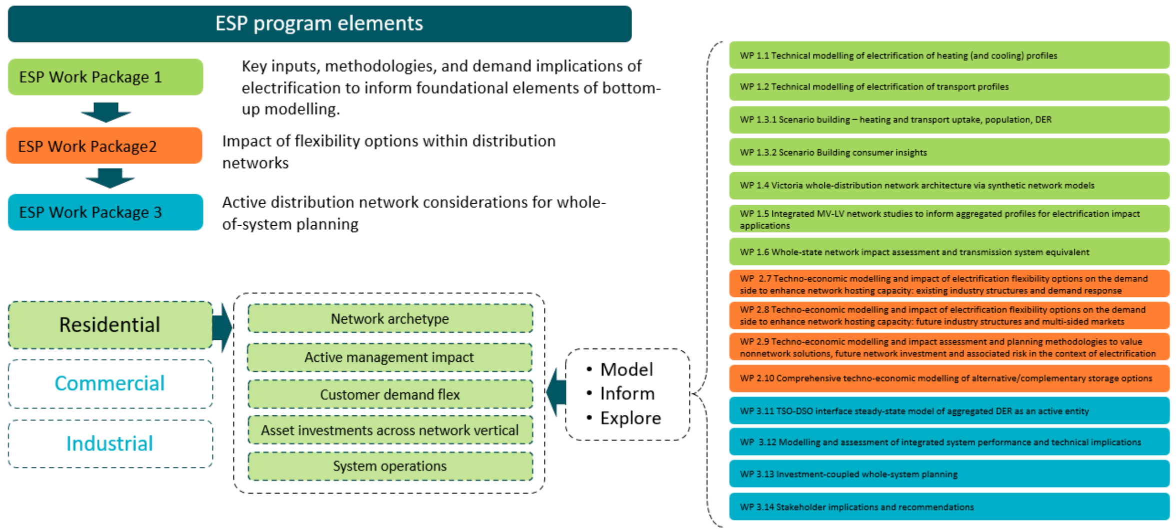
The Energy and Climate Change Ministerial Council (ECMC) accepted the recommendations of the review of the ISP which target transformation of the energy system as a whole, with particular reference to gas system planning, major industrial region planning and distribution systems.

Distribution system components of whole of system planning

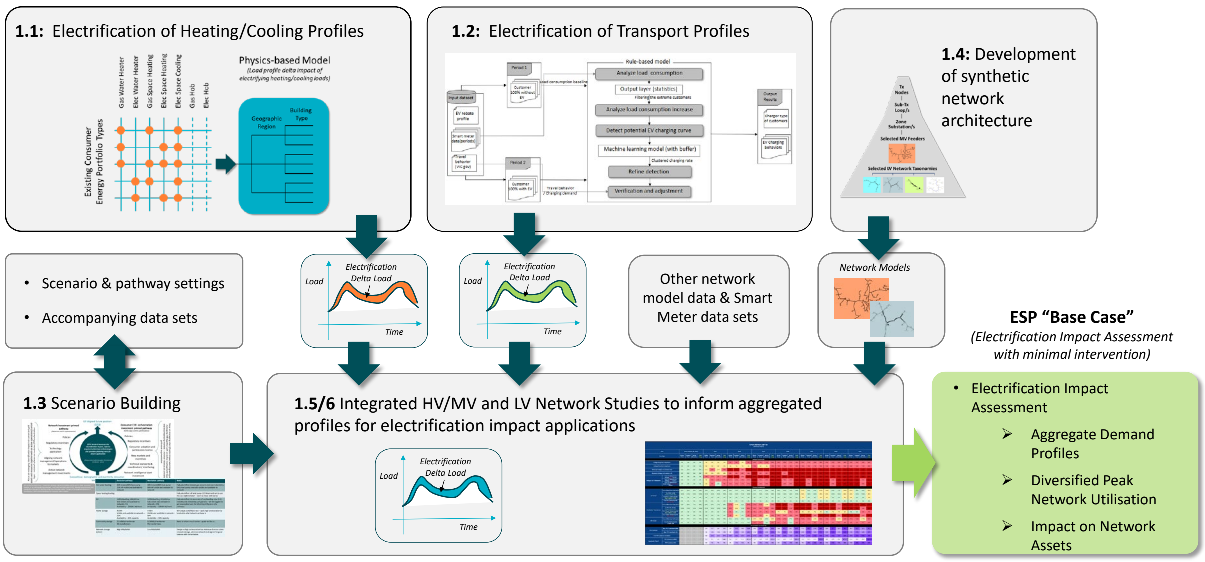


The ESP was scoped to be deliverable with the resources and time at hand to inform feasibility of broader application. It focussed on the more complex areas around residential and low voltage assets of the distribution system, with an application across Victorian networks with methodologies applicable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

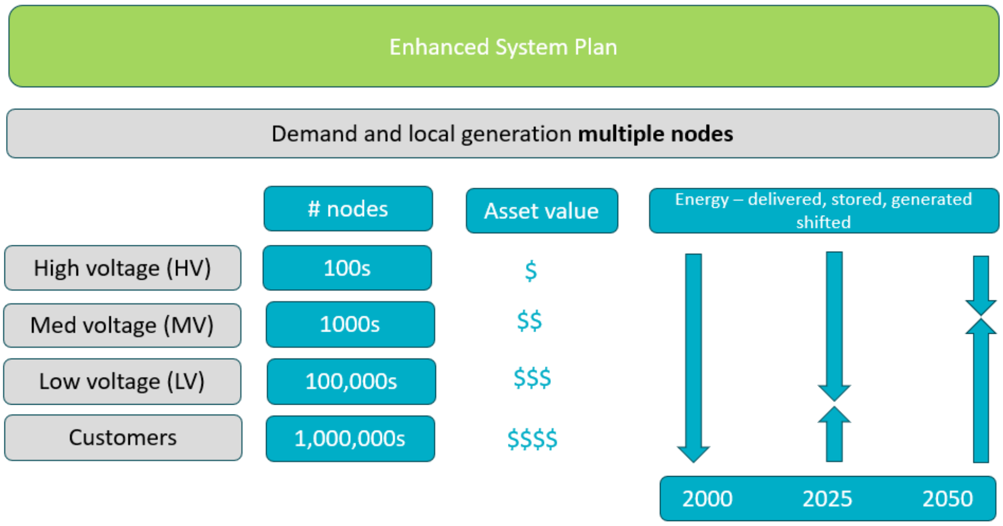
ESP alignment with distribution system components of whole of system planning



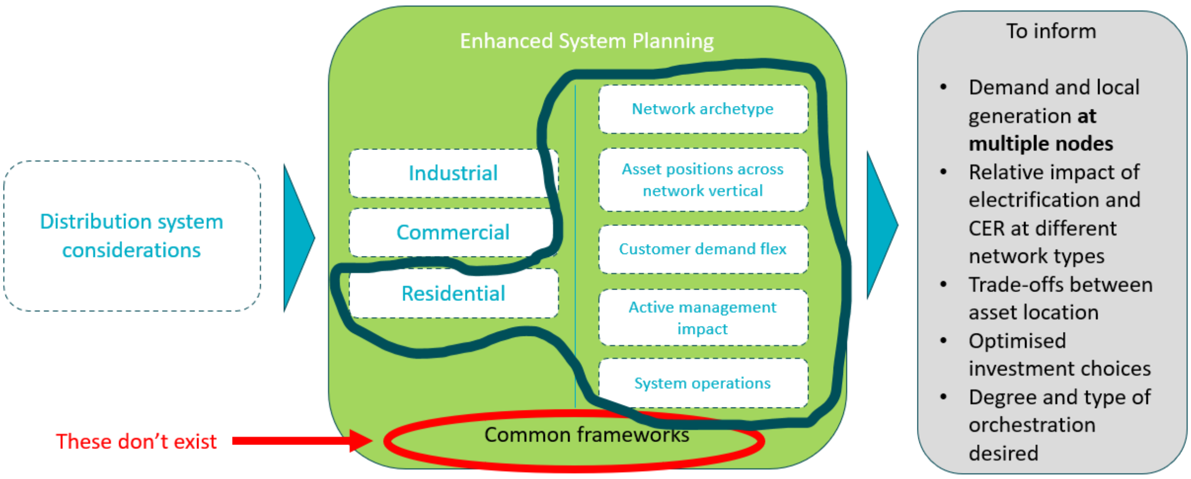
The 'base case' for residential electrification impact assessment, the flex options and relativity to other investment options



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



Methodological gaps in whole of system planning



Appendix Three – Impact assessment for selected sub-transmission networks without DOEs

Sub-transmission Network – CBTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			483	543	625	732	861	1027	1145
Increase of Max. Demand at Terminal Station (MVA)			-	12%	15%	17%	18%	19%	11%
Power Factor at Terminal Station for Max. Demand			0.98	0.98	0.96	0.94	0.91	0.85	0.8
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	37%	42%	63%
Maximum Voltage (pu)			1.06	1.06	1.06	1.06	1.06	1.06	1.06
Minimum Voltage (pu)			0.97	0.96	0.93	0.90	0.84	0.75	0.67
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	83%	75%	8%	8%	8%	8%	8%
		100%-110%	17%	8%	50%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	1.5	5	2.2	0	0	0	0
		110%-150%	0%	17%	42%	58%	42%	0%	0%
		Avg. Overloading Duration (hr)	0	2.5	5.5	5.9	9.7	0	0
		> 150%	0%	0%	0%	33%	50%	92%	92%
		Avg. Overloading Duration (hr)	0	0	0	2.6	6.2	8.4	10.7
	Max. Utilisation of the Worst Performing Transformer		106%	119%	138%	158%	195%	219%	228%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	85%	77%	38%	38%	38%
		100%-110%	0%	0%	0%	0%	15%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	1.8	0	0
		110%-150%	0%	0%	15%	23%	31%	31%	0%
		Avg. Overloading Duration (hr)	0	0	3.3	7.2	4.9	6.6	0
		> 150%	0%	0%	0%	0%	15%	31%	62%
		Avg. Overloading Duration (hr)	0	0	0	0	7	9.8	8.6
	Max. Utilisation of the Worst Performing Line		82%	98%	119%	148%	187%	245%	280%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	2%	6%	9%	12%	14%	18%
Residential Voltage Drop Non-Compliance			2%	5.3%	10%	14%	18%	23%	27%

% of LV Networks with Voltage Rise Issues		1%	9%	15%	18%	19%	21%	22%
% of LV Networks with Voltage Drop Issues		9%	17%	20%	23%	28%	33%	39%
% of LV Networks with Both Voltage Rise & Drop Issues		1%	9%	15%	18%	19%	21%	22%
MV-LV Thermal Assessment (extrapolation of metrics)								
% of Distribution Transformers with Maximum Utilisation	<= 100%	100%	97%	86%	75%	70%	64%	62%
	100%-110%	0.1%	2%	5%	4%	3%	3%	2%
	110%-150%	0.3%	0.5%	8%	16%	14%	10%	10%
	> 150%	0%	0.3%	0.8%	5%	14%	23%	26%
PV Curtailment Assessment (extrapolation of metrics)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	15	29	45	70	86	114	142
	% of PV Curtailment	6%	9%	12%	15%	18%	21%	24%

Table A3.1 - Impact assessment for the CBTS sub-transmission network without DOEs

Sub-transmission Network – ERTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			504	653	906	1254	1631	2049	2350
Increase of Max. Demand at Terminal Station (MVA)			-	30%	39%	38%	30%	26%	15%
Power Factor at Terminal Station for Max. Demand			1.00	0.97	0.91	0.83	0.77	0.69	0.64
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	26%	43%
Maximum Voltage (pu)			1.06	1.08	1.08	1.08	1.08	1.08	1.08
Minimum Voltage (pu)			0.98	0.98	0.98	0.97	0.94	0.75	0.71
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	88%	88%	65%	47%	47%	47%	47%
		100%-110%	12%	0%	12%	6%	0%	0%	0%
		Avg. Overloading Duration (hr)	3	0	3.3	4	0	0	0
		110%-150%	0%	12%	12%	24%	29%	0%	0%
		Avg. Overloading Duration (hr)	0	5.5	5	6.6	13.5	0	0
		> 150%	0%	0%	12%	24%	24%	53%	53%
		Avg. Overloading Duration (hr)	0	0	4.5	6	13.9	10.2	14.2
	Max. Utilisation of the Worst Performing Transformer		110%	150%	187%	282%	302%	307%	318%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	94%	75%	75%	62%	44%
		100%-110%	0%	0%	6%	6%	0%	12%	12%

		Avg. Overloading Duration (hr)	0	0	4	2.5	0	1	0.5
		110%-150%	0%	0%	0%	19%	12%	0%	19%
		Avg. Overloading Duration (hr)	0	0	0	5.8	6.8	0	1.2
		> 150%	0%	0%	0%	0%	12%	25%	25%
		Avg. Overloading Duration (hr)	0	0	0	0	4.3	9	12.1
	Max. Utilisation of the Worst Performing Line		66%	81%	108%	133%	168%	205%	241%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	1%	3%	5.3%	9%	12%	14%
Residential Voltage Drop Non-Compliance			1%	3%	9%	14%	19%	23%	26%
% of LV Networks with Voltage Rise Issues			1%	12%	20%	24%	26%	28%	28%
% of LV Networks with Voltage Drop Issues			12%	22%	26%	30%	34%	41%	45%
% of LV Networks with Both Voltage Rise & Drop Issues			1%	12%	20%	24%	25%	28%	28%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	97%	82%	67%	61%	56%	54%
		100%-110%	0%	3%	7%	4%	4%	3%	2%
		110%-150%	0.2%	0.2%	11%	22%	17%	11%	11%
		> 150%	0%	0.2%	0.3%	6%	18%	30%	33%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		28	55	84	120	163	216	268
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	24%

Table A3.2 - Impact assessment for the ERTS sub-transmission network without DOEs

Sub-transmission Network – GNTS + MBTS (Without DOEs)							
Year	**2023**	**2028**	**2033**	**2038**	**2043**	**2048**	**2053**
Terminal Stations Assessment (model-based simulations)							
Maximum Demand at GN Terminal Station (MVA)	104	136	184	239	287	344	380
Maximum Demand at MB Terminal Station (MVA)	23	28	36	44	52	62	70
Increase of Max. Demand at Terminal Stations (MVA)	-	29%	34%	29%	20%	20%	11%
Power Factor at GN Terminal Station for Max. Demand	0.97	0.93	0.91	0.87	0.85	0.82	0.80
Power Factor at MB Terminal Station for Max. Demand	1.00	1.00	0.98	0.97	0.97	0.95	0.94
HV Voltage Assessment (model-based simulations)							
% of Buses with Voltage Rise Issues	0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues	0%	0%	7%	13%	13%	20%	20%
Maximum Voltage (pu)	1.07	1.07	1.07	1.07	1.07	1.07	1.07
Minimum Voltage (pu)	0.99	0.95	0.86	0.76	0.71	0.66	0.63

HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	95%	91%	64%	50%	45%	45%	45%
		100%-110%	0%	5%	18%	0%	9%	0%	0%
		Avg. Overloading Duration (hr)	0	0.5	0.9	0	0.5	0	0
		110%-150%	5%	0%	14%	41%	18%	18%	18%
		Avg. Overloading Duration (hr)	1.1	0	0.7	4.2	3	3.1	3.4
		> 150%	0%	5%	5%	9%	27%	36%	36%
		Avg. Overloading Duration (hr)	0	0.3	0.9	1.3	2.6	4.9	5.8
	Max. Utilisation of the Worst Performing Transformer		123%	156%	171%	211%	223%	268%	286%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	100%	100%	100%	95%	95%
		100%-110%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		110%-150%	0%	0%	0%	0%	0%	5%	5%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0.2	0.7
		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Line		47%	55%	68%	81%	93%	111%	124%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	2%	5%	8%	10%	12%	22%
Residential Voltage Drop Non-Compliance			1%	4%	6%	8%	12%	15%	26%
% of LV Networks with Voltage Rise Issues			0.5%	4%	6%	7%	8%	9%	15%
% of LV Networks with Voltage Drop Issues			4%	7%	8%	10%	14%	16%	28%
% of LV Networks with Both Voltage Rise & Drop Issues			0.5%	4%	6%	6%	7%	9%	13%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	98%	95%	90%	84%	78%	72%	70%
		100%-110%	0.9%	1%	2%	3%	3%	3%	3%
		110%-150%	0.7%	3%	5%	8%	9%	11%	11%
		> 150%	0%	0.8%	3%	5%	9%	14%	16%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		5	9	14	20	27	35	44
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	23%

Table A3.3 - Impact assessment for the GNTS-MBTS sub-transmission network without DOEs

Sub-transmission Network – SMTS (Without DOEs)

Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			274	338	430	546	646	756	832
Increase of Max. Demand at Terminal Station (MVA)			-	23%	27%	27%	18%	17%	10%
Power Factor at Terminal Station for Max. Demand			1.00	0.99	0.98	0.96	0.94	0.92	0.91
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	21%	39%	45%	48%	48%
Maximum Voltage (pu)			1.04	1.04	1.05	1.06	1.05	1.06	1.06
Minimum Voltage (pu)			0.93	0.90	0.86	0.75	0.70	0.65	0.62
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	95%	85%	65%	60%	60%	50%	50%
		100%-110%	5%	5%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	1.5	3	0	0	0	0	0
		110%-150%	0%	10%	30%	30%	5%	15%	10%
		Avg. Overloading Duration (hr)	0	2	3.3	10	7	5	4.5
		> 150%	0%	0%	5%	10%	35%	35%	40%
		Avg. Overloading Duration (hr)	0	0	13.5	12	7.9	13.5	14.1
	Max. Utilisation of the Worst Performing Transformer		104%	118%	209%	306%	383%	422%	441%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	96%	84%	84%	64%	60%
		100%-110%	0%	0%	4%	4%	0%	8%	4%
		Avg. Overloading Duration (hr)	0	0	3	5.5	0	5	5
		110%-150%	0%	0%	0%	12%	8%	20%	24%
		Avg. Overloading Duration (hr)	0	0	0	6.2	8.5	6.9	7.3
		> 150%	0%	0%	0%	0%	8%	8%	12%
		Avg. Overloading Duration (hr)	0	0	0	0	3.3	10	10.5
	Max. Utilisation of the Worst Performing Line		66%	81%	106%	138%	158%	172%	181%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	2%	5%	8%	11%	13%	18%
Residential Voltage Drop Non-Compliance			2%	4%	8%	12%	16%	20%	26%
% of LV Networks with Voltage Rise Issues			0.5%	5%	9%	10%	11%	13%	17%
% of LV Networks with Voltage Drop Issues			5%	10%	12%	14%	18%	22%	32%
% of LV Networks with Both Voltage Rise & Drop Issues			0.5%	5%	9%	10%	11%	12%	16%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	99%	96%	88%	80%	75%	69%	67%
		100%-110%	0.6%	1%	4%	3%	3%	3%	3%

		110%-150%	0.6%	2%	6%	12%	11%	11%	10%
		> 150%	0%	0.6%	2%	5%	11%	18%	20%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		12	24	37	52	71	94	117
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	24%

Table A3.4 - Impact assessment for the SMTS sub-transmission network without DOEs

Sub-transmission Network – TSTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			359	433	538	659	781	912	1002
Increase of Max. Demand at Terminal Station (MVA)			-	20%	24%	22%	19%	17%	10%
Power Factor at Terminal Station for Max. Demand			0.99	0.99	0.98	0.97	0.96	0.96	0.95
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	0%	0%
Maximum Voltage (pu)			1.01	1.01	1.01	1.01	1.01	1.01	1.01
Minimum Voltage (pu)			0.99	0.99	0.99	0.99	0.99	0.99	0.98
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	100%	100%	100%	0%	0%	0%	0%
		100%-110%	0%	0%	0%	100%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	3.5	0	0	0
		110%-150%	0%	0%	0%	0%	100%	100%	100%
		Avg. Overloading Duration (hr)	0	0	0	0	4.3	7	10.8
		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Transformer		77%	86%	97%	110%	122%	134%	143%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	100%	100%	100%	100%	67%
		100%-110%	0%	0%	0%	0%	0%	0%	33%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	3
		110%-150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Line		52%	59%	67%	77%	85%	96%	103%

MV-LV Voltage Assessment (extrapolation of metrics)								
Residential Voltage Rise Non-Compliance		0%	1%	4%	6%	10%	12%	15%
Residential Voltage Drop Non-Compliance		2%	4%	9%	14%	18%	23%	26%
% of LV Networks with Voltage Rise Issues		0.8%	10%	16%	18%	20%	22%	23%
% of LV Networks with Voltage Drop Issues		10%	18%	21%	24%	30%	36%	41%
% of LV Networks with Both Voltage Rise & Drop Issues		0.8%	10%	16%	18%	20%	22%	23%
MV-LV Thermal Assessment (extrapolation of metrics)								
% of Distribution Transformers with Maximum Utilisation	<= 100%	100%	97%	84%	72%	66%	61%	59%
	100%-110%	0%	2%	6%	4%	3%	3%	2%
	110%-150%	0.2%	0.2%	9%	19%	15%	11%	10%
	> 150%	0%	0.2%	0.5%	5%	15%	26%	29%
PV Curtailment Assessment (extrapolation of metrics)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	12	23	35	50	69	91	113
	% of PV Curtailment	6%	9%	12%	15%	18%	21%	24%

Table A3.5 - Impact assessment for the TSTS sub-transmission network without DOEs

Sub-transmission Network – TTS (Without DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			254	340	475	640	820	983	1120
Increase of Max. Demand at Terminal Station (MVA)			-	34%	40%	35%	28%	20%	14%
Power Factor at Terminal Station for Max. Demand			1.00	0.98	0.95	0.92	0.87	0.83	0.79
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	8%	31%	54%	85%
Maximum Voltage (pu)			1.02	1.02	1.02	1.02	1.02	1.02	1.02
Minimum Voltage (pu)			0.99	0.97	0.95	0.92	0.82	0.76	0.73
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	100%	43%	14%	14%	0%	0%	0%
		100%-110%	0%	14%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	1.5	0	0	0	0	0
		110%-150%	0%	43%	71%	29%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	1.5	6.6	13.8	0	0	0
		> 150%	0%	0%	14%	57%	100%	100%	100%
		Avg. Overloading Duration (hr)	0	0	2	8.8	11.1	16.3	18.1

	Max. Utilisation of the Worst Performing Transformer		92%	114%	154%	202%	239%	267%	297%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	90%	80%	60%	60%	60%
		100%-110%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		110%-150%	0%	0%	10%	10%	20%	0%	0%
		Avg. Overloading Duration (hr)	0	0	3	5	4.5	0	0
		> 150%	0%	0%	0%	10%	20%	40%	40%
		Avg. Overloading Duration (hr)	0	0	0	0.5	7.5	7.4	10.5
	Max. Utilisation of the Worst Performing Line		65%	85%	114%	151%	194%	226%	244%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0%	1%	3%	4%	8%	11%	12%
Residential Voltage Drop Non-Compliance			1%	3%	9%	13%	18%	22%	24%
% of LV Networks with Voltage Rise Issues			1%	15%	25%	29%	31%	34%	34%
% of LV Networks with Voltage Drop Issues			15%	27%	31%	35%	41%	50%	53%
% of LV Networks with Both Voltage Rise & Drop Issues			1%	15%	25%	29%	31%	34%	34%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	96%	73%	53%	46%	41%	40%
		100%-110%	0%	4%	10%	6%	4%	4%	2%
		110%-150%	0%	0%	16%	33%	24%	13%	12%
		> 150%	0%	0%	0%	8%	26%	43%	47%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		15	29	44	63	85	113	140
	% of PV Curtailment		6%	9%	12%	15%	18%	21%	24%

Table A3.6 - Impact assessment for the TTS sub-transmission network without DOEs

Appendix Four – Impact assessment for selected sub-transmission networks with DOEs

Sub-transmission Network – CBTS (With DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			483	543	620	721	836	970	1078
Increase of Max. Demand at Terminal Station (MVA)			-	12%	14%	16%	16%	16%	11%
Power Factor at Terminal Station for Max. Demand			0.98	0.98	0.96	0.94	0.90	0.86	0.83
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	37%	42%	47%
Maximum Voltage (pu)			1.06	1.06	1.06	1.06	1.06	1.06	1.06
Minimum Voltage (pu)			0.97	0.96	0.93	0.90	0.84	0.78	0.70
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	83%	75%	33%	8%	8%	8%	8%
		100%-110%	17%	8%	33%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	1.5	5	4.5	0	0	0	0
		110%-150%	0%	17%	33%	75%	50%	33%	0%
		Avg. Overloading Duration (hr)	0	2.5	6.8	7.7	10.3	14.5	0
		> 150%	0%	0%	0%	17%	42%	58%	92%
		Avg. Overloading Duration (hr)	0	0	0	2	6.3	8.8	8.6
	Max. Utilisation of the Worst Performing Transformer		106%	119%	136%	155%	187%	218%	218%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	85%	77%	46%	38%	38%
		100%-110%	0%	0%	0%	0%	8%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0.5	0	0
		110%-150%	0%	0%	15%	23%	31%	38%	15%
		Avg. Overloading Duration (hr)	0	0	3	6.3	2.8	5.9	7.3
		> 150%	0%	0%	0%	0%	15%	23%	46%
		Avg. Overloading Duration (hr)	0	0	0	0	6	10.5	7.4
	Max. Utilisation of the Worst Performing Line		82%	98%	118%	146%	180%	228%	259%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.3%	2%	4%	7%	8%	8%	10%
Residential Voltage Drop Non-Compliance			2%	5.1%	8%	12%	15%	20%	25%

% of LV Networks with Voltage Rise Issues		0.8%	8%	13%	14%	13%	15%	16%
% of LV Networks with Voltage Drop Issues		9%	16%	19%	22%	25%	30%	34%
% of LV Networks with Both Voltage Rise & Drop Issues		0.8%	8%	13%	13%	13%	14%	15%
MV-LV Thermal Assessment (extrapolation of metrics)								
% of Distribution Transformers with Maximum Utilisation	<= 100%	100%	97%	89%	76%	73%	68%	65%
	100%-110%	0.1%	2%	3%	5%	3%	4%	4%
	110%-150%	0.3%	0.5%	8%	16%	15%	11%	10%
	> 150%	0%	0.3%	0.7%	3%	10%	17%	21%
PV Curtailment Assessment (extrapolation of metrics)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	23	38	74	150	198	255	304
	% of PV Curtailment	6%	8%	13%	24%	28%	31%	34%
EV Management Assessment (extrapolation of metrics)								
% of EVs Affected		-	-	9%	12%	16%	20%	24%
Average EV Charging Delay (h)		-	-	3.3	4.9	5	4.9	4.8
Average EV Charging Delay (h)		-	-	3.7	5.2	5.6	5.5	5.4

Table A4.1 - Impact assessment for the CBTS sub-transmission network with DOEs

Sub-transmission Network – ERTS (With DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			504	653	896	1189	1462	1858	2032
Increase of Max. Demand at Terminal Station (MVA)			-	30%	37%	33%	23%	27%	9%
Power Factor at Terminal Station for Max. Demand			1.00	0.97	0.90	0.84	0.80	0.74	0.71
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	17%	26%
Maximum Voltage (pu)			1.06	1.08	1.08	1.08	1.08	1.08	1.08
Minimum Voltage (pu)			0.98	0.98	0.98	0.97	0.96	0.80	0.74
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	88%	88%	71%	47%	47%	47%	47%
		100%-110%	12%	0%	6%	6%	0%	0%	0%
		Avg. Overloading Duration (hr)	3	0.0	3	1	0	0	0
		110%-150%	0%	12%	12%	24%	29%	12%	0%
		Avg. Overloading Duration (hr)	0	4.5	5.5	3.5	10.5	17.3	0
		> 150%	0%	0%	12%	24%	24%	41%	53%

		Avg. Overloading Duration (hr)	0	0	6	5.9	13.5	10	10.2
	Max. Utilisation of the Worst Performing Transformer		110%	137%	194%	232%	271%	303%	313%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	94%	81%	75%	75%	62%
		100%-110%	0%	0%	6%	0%	0%	0%	12%
		Avg. Overloading Duration (hr)	0	0	4	0	0	0	1
		110%-150%	0%	0%	0%	19%	12%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	5.8	5.8	0	0
		> 150%	0%	0%	0%	0%	12%	25%	25%
		Avg. Overloading Duration (hr)	0	0	0	0	1.8	5.6	9.4
	Max. Utilisation of the Worst Performing Line		66%	81%	106%	129%	156%	204%	207%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.1%	1%	2%	3%	4%	5.1%	4%
Residential Voltage Drop Non-Compliance			1%	3%	8%	12%	15%	20%	24%
% of LV Networks with Voltage Rise Issues			1%	11%	17%	18%	16%	19%	19%
% of LV Networks with Voltage Drop Issues			12%	21%	26%	28%	31%	35%	39%
% of LV Networks with Both Voltage Rise & Drop Issues			1%	11%	17%	18%	16%	18%	18%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	97%	85%	68%	64%	60%	56%
		100%-110%	0%	3%	4%	7%	3%	4%	4%
		110%-150%	0.2%	0.2%	11%	22%	19%	13%	12%
		> 150%	0%	0.2%	0.3%	3%	13%	23%	28%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		38	65	125	244	336	450	536
	% of PV Curtailment		6%	8%	13%	23%	28%	33%	36%
EV Management Assessment (extrapolation of metrics)									
% of EVs Affected			-	-	9%	13%	16%	21%	24%
Average EV Charging Delay (h)			-	-	3.7	5.2	5.6	5.5	5.4

Table A4.2 - Impact assessment for the ERTS sub-transmission network with DOEs

Sub-transmission Network – GNTS + MBTS (With DOEs)							
Year	2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)							
Maximum Demand at GN Terminal Station (MVA)	104	133	185	239	276	320	341
Maximum Demand at MB Terminal Station (MVA)	23	28	36	44	52	59	67
Increase of Max. Demand at Terminal Stations (MVA)	-	28%	39%	29%	15%	16%	7%

Power Factor at GN Terminal Station for Max. Demand			0.97	0.95	0.90	0.87	0.86	0.83	0.83
Power Factor at MB Terminal Station for Max. Demand			1.00	1.00	0.98	0.97	0.97	0.95	0.93
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	7%	13%	13%	20%	20%
Maximum Voltage (pu)			1.07	1.07	1.07	1.07	1.07	1.07	1.07
Minimum Voltage (pu)			0.99	0.95	0.86	0.77	0.72	0.68	0.65
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	95%	95%	64%	50%	50%	45%	45%
		100%-110%	0%	0%	18%	0%	5%	5%	5%
		Avg. Overloading Duration (hr)	0	0	0.8	0	0.05	0.2	0.8
		110%-150%	5%	5%	14%	41%	18%	14%	23%
		Avg. Overloading Duration (hr)	1.1	0.6	0.7	3.8	2.7	2.1	1.5
		> 150%	0%	0%	5%	9%	27%	36%	27%
		Avg. Overloading Duration (hr)	0	0	0.9	1.1	2	4.4	1.8
	Max. Utilisation of the Worst Performing Transformer		123%	132%	171%	211%	183%	223%	221%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	100%	100%	100%	95%	95%
		100%-110%	0%	0%	0%	0%	0%	5%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0.7	0
		110%-150%	0%	0%	0%	0%	0%	0%	5%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0.8
		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Line		47%	55%	69%	81%	93%	107%	119%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.3%	2%	4%	7%	7%	7%	18%
Residential Voltage Drop Non-Compliance			1%	4%	5.2%	7%	9%	13%	24%
% of LV Networks with Voltage Rise Issues			0.5%	3%	5%	5%	5%	7%	12%
% of LV Networks with Voltage Drop Issues			4%	6%	7%	10%	12%	16%	26%
% of LV Networks with Both Voltage Rise & Drop Issues			0.5%	3%	5%	5%	5%	6%	10%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	98%	95%	92%	86%	82%	77%	75%
		100%-110%	0.9%	1%	2%	3%	2%	4%	4%
		110%-150%	0.7%	3%	4%	7%	8%	9%	9%
		> 150%	0%	0.8%	3%	4%	7%	10%	12%
PV Curtailment Assessment (extrapolation of metrics)									

		2023	2028	2033	2038	2043	2048	2053
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	8	14	23	45	59	77	93
	% of PV Curtailment	6%	7%	11%	19%	22%	25%	27%
EV Management Assessment (extrapolation of metrics)								
% of EVs Affected		-	-	8%	12%	16%	20%	24%
Average EV Charging Delay (h)		-	-	3	4.1	4.2	4.1	4.1

Table A4.3 - Impact assessment for the GNTS-MBTS sub-transmission network with DOEs

Subtransmission Network – SMTS (With DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			274	338	431	540	627	713	776
Increase of Max. Demand at Terminal Station (MVA)			-	23%	28%	25%	16%	14%	9%
Power Factor at Terminal Station for Max. Demand			1.00	0.99	0.97	0.95	0.93	0.93	0.91
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	18%	39%	42%	42%	45%
Maximum Voltage (pu)			1.04	1.04	1.05	1.05	1.06	1.05	1.05
Minimum Voltage (pu)			0.93	0.90	0.85	0.75	0.70	0.66	0.64
HV Thermal Assessment (model-based simulations)									
HV Transformers	% of Transformers with Maximum Utilisation	<= 100%	95%	85%	65%	60%	60%	50%	50%
		100%-110%	5%	5%	15%	5%	0%	10%	0%
		Avg. Overloading Duration (hr)	1.5	3	4.5	6	0	5.5	0
		110%-150%	0%	10%	15%	25%	5%	5%	10%
		Avg. Overloading Duration (hr)	0	2	5.7	10.1	6.5	10.5	2.5
		> 150%	0%	0%	5%	10%	35%	35%	40%
		Avg. Overloading Duration (hr)	0	0	14	12.3	7.6	12.6	13
	Max. Utilisation of the Worst Performing Transformer		104%	118%	212%	305%	370%	414%	425%
HV Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	96%	84%	84%	64%	60%
		100%-110%	0%	0%	4%	4%	0%	20%	4%
		Avg. Overloading Duration (hr)	0	0	2.5	5	0	2.8	2
		110%-150%	0%	0%	0%	12%	12%	8%	24%
		Avg. Overloading Duration (hr)	0	0	0	6.3	9.8	14	4
		> 150%	0%	0%	0%	0%	4%	8%	12%
		Avg. Overloading Duration (hr)	0	0	0	0	4.5	8.5	8.7
	Max. Utilisation of the Worst Performing Line		66%	81%	106%	139%	156%	168%	176%

MV-LV Voltage Assessment (extrapolation of metrics)								
Residential Voltage Rise Non-Compliance		0.3%	2%	4%	6%	6%	7%	11%
Residential Voltage Drop Non-Compliance		2%	4%	7%	10%	13%	18%	24%
% of LV Networks with Voltage Rise Issues		0.5%	5%	7%	8%	7%	9%	13%
% of LV Networks with Voltage Drop Issues		5%	9%	11%	13%	16%	20%	29%
% of LV Networks with Both Voltage Rise & Drop Issues		0.5%	5%	7%	8%	7%	8%	11%
MV-LV Thermal Assessment (extrapolation of metrics)								
% of Distribution Transformers with Maximum Utilisation	<= 100%	99%	96%	90%	82%	78%	74%	71%
	100%-110%	0.6%	1%	2%	4%	2%	4%	4%
	110%-150%	0.6%	2%	6%	11%	11%	10%	10%
	> 150%	0%	0.6%	2%	4%	8%	13%	16%
PV Curtailment Assessment (extrapolation of metrics)								
% of PV Customers Curtailed		100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)	19	32	59	117	156	204	244
	% of PV Curtailment	6%	8%	12%	22%	26%	30%	32%
EV Management Assessment (extrapolation of metrics)								
% of EVs Affected		-	-	9%	12%	16%	20%	24%
Average EV Charging Delay (h)		-	-	3.2	4.7	4.9	4.8	4.7

Table A4.4 - Impact assessment for the SMTS sub-transmission network with DOEs

Sub-transmission Network – TSTS (With DOEs)									
Year			2023	2028	2033	2038	2043	2048	2053
Terminal Station (model-based simulations)									
Maximum Demand at Terminal Station (MVA)			359	433	530	647	755	861	936
Increase of Max. Demand at Terminal Station (MVA)			-	20%	23%	22%	17%	14%	9%
Power Factor at Terminal Station for Max. Demand			0.99	0.99	0.97	0.97	0.96	0.95	0.95
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	0%	0%	0%
Maximum Voltage (pu)			1.01	1.01	1.01	1.01	1.01	1.01	1.01
Minimum Voltage (pu)			0.99	0.99	0.99	0.99	0.99	0.99	0.98
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	100%	100%	100%	0%	0%	0%	0%
		100%-110%	0%	0%	0%	100%	33%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	3.2	5.5	0	0
		110%-150%	0%	0%	0%	0%	67%	100%	100%
		Avg. Overloading Duration (hr)	0	0	0	0	4.5	7	8.3

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		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Transformer		77%	86%	96%	108%	118%	130%	138%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	100%	100%	100%	100%	100%
		100%-110%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		110%-150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		> 150%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
	Max. Utilisation of the Worst Performing Line		52%	59%	66%	76%	84%	93%	100%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.2%	1%	3%	4%	5.1%	6%	5.5%
Residential Voltage Drop Non-Compliance			2%	4%	8%	12%	15%	20%	24%
% of LV Networks with Voltage Rise Issues			0.8%	9%	13%	14%	13%	15%	15%
% of LV Networks with Voltage Drop Issues			10%	17%	20%	22%	26%	31%	35%
% of LV Networks with Both Voltage Rise & Drop Issues			0.8%	8%	13%	14%	13%	15%	15%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	97%	87%	73%	69%	65%	62%
		100%-110%	0%	2%	3%	6%	3%	4%	4%
		110%-150%	0.2%	0.2%	9%	19%	17%	12%	11%
		> 150%	0%	0.2%	0.5%	3%	11%	19%	24%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%
Aggregate Export	Total PV Curtailment (GWh)		17	28	54	106	145	193	230
	Percentage of PV Curtailment		6%	8%	13%	23%	28%	32%	35%
EV Management Assessment (extrapolation of metrics)									
% of EVs Affected			-	-	9%	12%	16%	20%	24%
Average EV Charging Delay (h)			-	-	3.5	5.1	5.4	5.4	5.3

Table A4.5 - Impact assessment for the TSTS sub-transmission network with DOEs

Sub-transmission Network – TTS (With DOEs)							
Year	2023	2028	2033	2038	2043	2048	2053
Terminal Station Assessment (model-based simulations)							
Maximum Demand at Terminal Station (MVA)	254	340	468	626	785	918	1013
Increase of Max. Demand at Terminal Station (MVA)	-	34%	38%	34%	25%	17%	10%

Power Factor at Terminal Station for Max. Demand			1.00	0.98	0.95	0.92	0.87	0.84	0.81
HV Voltage Assessment (model-based simulations)									
% of Buses with Voltage Rise Issues			0%	0%	0%	0%	0%	0%	0%
% of Buses with Voltage Drop Issues			0%	0%	0%	0%	8%	54%	54%
Maximum Voltage (pu)			1.02	1.02	1.02	1.02	1.02	1.02	1.02
Minimum Voltage (pu)			0.99	0.97	0.95	0.93	0.82	0.78	0.75
HV Thermal Assessment (model-based simulations)									
Zone Substation Transformers	% of Transformers with Maximum Utilisation	<= 100%	100%	43%	14%	14%	0%	0%	0%
		100%-110%	0%	14%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	1.5	0	0	0	0	0
		110%-150%	0%	43%	86%	29%	14%	0%	0%
		Avg. Overloading Duration (hr)	0	1.5	7.4	11.3	17.0	0	0
		> 150%	0%	0%	0%	57%	86%	100%	100%
		Avg. Overloading Duration (hr)	0	0	0	7.8	11.6	15.1	16.9
	Max. Utilisation of the Worst Performing Transformer		92%	114%	149%	198%	232%	252%	273%
Sub-transmission Lines	% of Lines with Maximum Utilisation	<= 100%	100%	100%	90%	80%	60%	60%	60%
		100%-110%	0%	0%	0%	0%	0%	0%	0%
		Avg. Overloading Duration (hr)	0	0	0	0	0	0	0
		110%-150%	0%	0%	10%	20%	20%	20%	0%
		Avg. Overloading Duration (hr)	0	0	1.5	7.3	1.0	8.5	0
		> 150%	0%	0%	0%	0%	20%	20%	40%
		Avg. Overloading Duration (hr)	0	0	0	0	4.5	11.8	7.9
	Max. Utilisation of the Worst Performing Line		65%	85%	112%	147%	186%	214%	229%
MV-LV Voltage Assessment (extrapolation of metrics)									
Residential Voltage Rise Non-Compliance			0.1%	0.8%	2%	2%	3%	4%	3%
Residential Voltage Drop Non-Compliance			1%	3%	7%	11%	15%	19%	23%
% of LV Networks with Voltage Rise Issues			1%	13%	20%	21%	19%	22%	21%
% of LV Networks with Voltage Drop Issues			15%	26%	31%	32%	37%	38%	43%
% of LV Networks with Both Voltage Rise & Drop Issues			1%	13%	20%	21%	19%	21%	21%
MV-LV Thermal Assessment (extrapolation of metrics)									
% of Distribution Transformers with Maximum Utilisation		<= 100%	100%	96%	78%	54%	48%	45%	41%
		100%-110%	0%	4%	6%	10%	5%	5%	4%
		110%-150%	0%	0%	16%	32%	28%	17%	15%
		> 150%	0%	0%	0%	4%	19%	33%	40%
PV Curtailment Assessment (extrapolation of metrics)									
% of PV Customers Curtailed			100%	100%	100%	100%	100%	100%	100%

Aggregate Export	Total PV Curtailment (GWh)	20	34	63	122	170	232	276
	% of PV Curtailment	6%	8%	13%	22%	27%	33%	35%
EV Management Assessment (extrapolation of metrics)								
% of EVs Affected		-	-	9%	13%	16%	21%	24%
Average EV Charging Delay (h)		-	-	3.8	5.2	5.7	5.7	5.5

Table A4.6 - Impact assessment for the TTS sub-transmission network with DOEs

Appendix Five – Verification of Pseudo LV Network Approach with Real LV Networks

Ten real LV networks (corresponding to ten sites), provided by Powercor (one of the Victorian DNSPs), are used to assess the accuracy of the pseudo-LV network models produced in WP 1.4. For details on pseudo-LV network modelling approach, refer to the WP 1.4 final report.

Both real and pseudo network models are delivered in OpenDSS files. Table A3.1 and Table A5.2 - A3.2 summarize the characteristics of these real and corresponding pseudo-LV network models (e.g., transformer capacity, number of feeders, number of customers). The tables are organised in ascending order based on the number of residential customers at each site. Comparing both tables highlights the differences between the pseudo-LV network models and their real counterparts. This assessment examines how these differences affect the electrification assessment.

Site	Tx Rated Capacity (kVA)	No. Customers		No. Feeders	RES Customers per Phase		
		Residential	C & I		Ph A	Ph B	Ph C
9	500	0	24	2	0	0	0
5	10	1	0	1	1	0	0
10	500	1	9	3	1	0	0
6	315	2	14	5	1	1	0
3	315	2	14	5	1	1	0
7	1000	4	5	1	2	1	1
2	50	6	0	4	2	2	2
1	50	22	2	2	8	7	7
8	315	44	15	5	15	15	14
4	315	131	2	5	45	42	44

Table A5.1 - Summary of real LV network models

Site	Tx Rated Capacity (kVA)	No. Customers		No. Feeders	RES Customers per Phase		
		Residential	C & I		Ph A	Ph B	Ph C
9	500	0	1	0	0	0	0
5	10	1	0	1	1	0	0
10	500	1	1	1	1	0	0
6	315	2	1	1	1	1	0
3	315	2	1	1	1	1	0
7	1000	4	1	1	2	1	1
2	50	6	0	1	2	2	2
1	50	22	1	2	8	7	7
8	315	44	1	3	15	15	14
4	315	131	1	7	46	46	39

Table A5.2 - Summary of pseudo-LV Network models

In this study, only networks with residential customers are considered; therefore, Site 9 is disregarded (no residential customer). Furthermore, three load scenarios were considered to assess the behaviour of the pseudo-networks in different conditions.

Peak Load: This scenario considers a load of 4.4 kW per residential customer (0.98 power factor, lagging), representing a high import condition.

Medium Load: This scenario considers a load of 2.2 kW per residential customer (0.98 power factor, lagging), represents a medium import condition.

Peak Export: This scenario represents high export conditions, where there is no residential load, and 5 kW export for each residential customer (e.g., PV).

Note the load from C&I customers is kept the same in these scenarios.

The assessment considered the following key metrics based on the described scenarios:

Customer voltage: Represents the maximum, minimum, and average customer voltages.

Voltage at the furthest customer node: Indicates the three-phase voltage at the most distant node with a connected customer.

Line utilisation at the head of the feeder: Assesses the adequacy of conductor selection in the network.

Total active power losses: Evaluate overall network efficiency.

Table A5.3 summarises customer voltage results, which is the primary metric for assessing the performance of the pseudo-LV networks.

Site	Tx Rated Capacity (kVA)	Peak Load (kW)		Scenario	Customer voltages Δ (%)	
		Residential	Commercial		Min	Max
5	10	4.4	0	Peak Load 4.4kW	0%	0%
				No Load + 100% PV	0%	0%
10	500	4.4	270	Peak Load 4.4kW	0%	0%
				No Load + 100% PV	1%	1%
6	315	8.8	252	Peak Load 4.4kW	2%	2%
				No Load + 100% PV	2%	1%
3	315	8.8	252	Peak Load 4.4kW	1%	1%
				No Load + 100% PV	1%	1%
7	1000	17.6	600	Peak Load 4.4kW	12%	9%
				No Load + 100% PV	10%	8%
2	50	26.4	0	Peak Load 4.4kW	-1%	0%
				No Load + 100% PV	0%	1%
1	50	96.8	20	Peak Load 4.4kW	14%	1%
				No Load + 100% PV	0%	-5%
8	315	193.6	120	Peak Load 4.4kW	5%	0%
				No Load + 100% PV	0%	-1%
4	315	576.4	20	Peak Load 4.4kW	8%	1%
				No Load + 100% PV	0%	-4%

Table A5.3 - Results of the Customer Voltage Comparison

The primary metric-based findings of the comparison are presented in Table A5.4, where the networks are categorised into three ranges based on their transformer rated capacity: A (up to 315 kV), B (between 315-500 kVA), and C (more than 500 kVA). Additionally, two subcategories are considered based on the proportion of residential customers: networks with more than 90% residential customers and those with less than 90%. Within each category range, the following conclusions can be drawn:

Range A (up to 315 kVA): In largely residential networks (more than 90%), pseudo-LV networks produce voltage results similar to the real networks.

Range B (between 315-500 kVA): Pseudo-LV networks tend to underestimate voltage rises but overestimate voltage drops.

Range C (more than 500 kVA): In mixed networks with less than 90% residential customers, pseudo-LV networks overestimated both voltage rises and drops.

Tx Rated Capacity	Largely RES (>90% Load RES)		Mixed with C&I (<90%. Load RES)	
	Voltage Rise	Voltage Drop	Voltage Rise	Voltage Drop
Range A: Up to 315 kVA	Overestimates ~1%	Underestimates ~1%	Underestimates ~5%	Overestimates ~14%
Range B: Between 315-500 kVA	Underestimates ~4%	Overestimates ~8%	Underestimates ~1%	Overestimates ~5%
Range C: More than 500 kVA	-	-	Overestimates ~9%	Overestimates ~12%

Table A5.4 - Summary of the conclusions

Applying these conclusions to the networks assessed in this project, the following points can be highlighted:

Urban Network SBY32: Around 20% of the pseudo-LV networks produce voltage results comparable to real networks, as they belong to Range A and are largely residential. However, the remaining 80% are more likely to underestimate voltage rises and overestimate voltage drops, given that the LV distribution transformers in this network mostly fall within Range B and C.

Suburban Network WBE013: Approximately 50% of the LV distribution transformers in this network fall within Range B, meaning the pseudo-LV networks tend to underestimate voltage rises and overestimate voltage drops.

Short-Rural COO012 and Long-Rural BAS033 Networks: Pseudo-LV networks provide voltage results similar to real networks, as more than 80% of the LV distribution transformers in these networks fall within Range A and are largely residential.

For line utilisation, the pseudo-LV networks under-estimate the line utilisation compared with the real networks, for the majority of the circuits considered (Table A5.5):

Site	No. Customers		Scenario	Line Util HoF1 Δ (%)			Total Losses	
	Residential	Commercial		Ph A	Ph B	Ph C	Δ (kW)	Δ (%)
5	1	0	**Peak Load** 4.4kW	2%	0%	0%	0.0	-13%
			Medium Load 2.2kW	1%	0%	0%	0.0	-9%
			No Load + 100% PV	2%	0%	0%	0.0	-11%
10	1	9	**Peak Load** 4.4kW	-65%	-73%	-73%	-2.6	-35%
			Medium Load 2.2kW	-69%	-73%	-73%	-2.6	-36%
			No Load + 100% PV	-64%	-73%	-73%	-2.5	-36%
6	2	14	**Peak Load** 4.4kW	-65%	-65%	-64%	-1.3	-18%
			Medium Load 2.2kW	-64%	-64%	-64%	-1.2	-16%
			No Load + 100% PV	-47%	-47%	-64%	-0.8	-12%
3	2	14	**Peak Load** 4.4kW	-69%	-76%	-76%	-3.9	-39%
			Medium Load 2.2kW	-73%	-76%	-76%	-3.8	-39%
			No Load + 100% PV	-68%	-76%	-76%	-3.5	-39%
7	4	5	**Peak Load** 4.4kW	-68%	-73%	-73%	-39.7	-77%
			Medium Load 2.2kW	-73%	-76%	-76%	-37.8	-77%
			No Load + 100% PV	-57%	-67%	-67%	-32.8	-76%
2	6	0	**Peak Load** 4.4kW	10%	10%	10%	0.0	6%
			Medium Load 2.2kW	5%	5%	5%	0.0	4%
			No Load + 100% PV	11%	10%	11%	0.0	6%
1	22	2	**Peak Load** 4.4kW	-5%	0%	0%	-9.7	-53%
			Medium Load 2.2kW	-7%	-4%	-3%	-2.7	-50%
			No Load + 100% PV	14%	14%	14%	-3.0	-41%
8	44	15	**Peak Load** 4.4kW	-93%	-84%	-102%	-11.0	-51%
			Medium Load 2.2kW	-77%	-73%	-81%	-4.7	-50%
			No Load + 100% PV	-16%	-9%	-24%	-2.5	-41%
4	131	2	**Peak Load** 4.4kW	-69%	-51%	-84%	-15.6	-28%
			Medium Load 2.2kW	-33%	-29%	-45%	-3.3	-25%
			No Load + 100% PV	-64%	-48%	-62%	-9.8	-22%

Table A5.5 - Results of the Line Utilisation Comparison

Appendix Six – ESP project and research partners