31 January 2023

Attachment 5.6.d: HV & LV augmentation programs

Ausgrid's 2024-29 Regulatory Proposal

Empowering communities for a resilient, affordable and net-zero future.

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Contents

1 Executive Summary

1.1 Purpose of this document

This document provides a summary of the high voltage (**HV**) and low voltage (**LV**) capacity programs (excluding major projects) under the driver of augmentation.

These programs aim to ensure that HV and LV customer's loads can be supplied without overloading equipment, while maintaining voltage levels within the ranges expected by customers. They form part of Ausgrid's overall forecast standard control capital expenditure (**capex**) for the 2025--29 regulatory period.

1.2 HV and LV Augmentation Forecast Expenditure

Ausgrid is proposing augmentation of $81.2million across the HV and LV programs, as compared to the allowance of $86 million in the current (2020–2024) regulatory period. The forecast expenditure across the different components of the HV and LV programs is summarised in **Table 1**.

Table 1: Summary of proposed HV and LV augmentation expenditure (real $million, FY24)

Program Description	Forecast Capex real $million, FY24					
	FY25	FY26	FY27	FY28	FY29	TOTAL
HV Reinforcement Overhead	3.3	3.3	3.4	3.4	3.4	16.8
HV Reinforcement Underground	6.2	6.2	6.3	6.4	6.4	31.4
HV Total	9.5	9.5	9.7	9.7	9.8	48.1
LV Distribution Centre Capacity	1.4	1.4	1.4	1.4	1.4	7.1
Voltage Management Tap Change	0.1	0.1	0.1	0.1	0.1	0.5
LV Distributor Capacity	4.4	4.5	4.5	4.5	4.5	22.4
LV Load Survey	0.6	0.6	0.6	0.6	0.6	3.0
LV Total	6.5	6.6	6.6	6.7	6.7	33.1
TOTAL	16.0	16.1	16.3	16.3	16.5	81.2

Demand for network services changes over time as new customers connect to Ausgrid's network and existing customers change their energy consumption. Increased demand affects Ausgrid's ability to maintain supply under peak conditions, provide windows for routine maintenance and alterations, and to restore supply following outages. Operating assets above their ratings can also decrease their lifespan.

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Ausgrid's HV and LV programs provide for augmentation of the shared distribution network to support:

- Load from customers connecting via basic connection services (those below the augmentation thresholds specified in Ausgrid's Connection Policy);
- The upstream impacts of the connection of other customers (new connection agreements); and
- The changing behaviour of Ausgrid's existing customer base within their existing connection agreements, such as increasing their overall load or changes in coincidence of customer demand during peak periods.

This program does not include extensions required for customer connections. Larger connecting customers (those requesting standard and negotiated services) fund augmentation needed to support their connection.

Ausgrid's HV and LV networks are assessed on an annual cycle to identify risks (i.e. locations where technical thresholds are currently or are forecast to be exceeded). Both normal system conditions and conditions with certain critical elements out of service (credible contingencies). Assessment includes the severity of each risk identified and the cost-effectiveness of mitigation options. The level of detail of the analysis and number of options considered is proportionate to the risk and the costs of the credible risk mitigation actions.

Load based risks on the HV and LV network are strongly related to the localised decisions and behaviour of customers. Ausgrid's investment forecasting approach estimates overall network investment requirements based on expected customer behaviour over a large population of similar network assets (e.g. 65,000 LV distributors). While specific investments are made reactively as locational risks emerge, the total volumes of issues for an area can be predicted over longer periods using historical data adjusted for high-level forecast demand requirements. Investigation thresholds and project initiation is dependent on identification and adoption of credible risk mitigation options that have a positive cost-benefit analysis (**CBA**).

1.3 HV Program Components

The 11kV Network Reinforcement Program addresses capacity shortfalls in Ausgrid's HV distribution network. This program covers over 2,500 HV feeders which consist of over 10,000km of overhead (**OH**) circuit and over 8,000km of underground (**UG**) circuit. This program has two components that correspond to each construction type.

1.4 LV Program Components

There are four LV programs:

- The LV Distributor Capacity Program addresses capacity shortfalls in Ausgrid's LV distribution network. This program covers over 65,000 LV distributors, which consist of over 13,000km of OH circuit and over 6,000km of UG circuit;
- The Distribution Centre Capacity Program addresses capacity shortfalls in Ausgrid's distribution substations. This program covers over 32,000 substations, which consist of approximately 16,000 pole mounted transformers and 16,000 ground mounted substations;

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- The Voltage Management Tap Change Program continues Ausgrid's staged migration to 230V to ensure that voltages at customer connection points are within compliance limits set out by Australian standards. This is distinct from investment to support projected new connections of Distributed Energy Resources (**DER**), which also affects voltage performance. DER integration investment is modelled separately; and
- The Load Survey program provides for the installation of temporary network monitors to collect load and power quality information where there are no other reliable sources of data. This data is used to confirm and assess particular network risks, and to calibrate network models used for global analysis and screening.

1.5 Comparison with current regulatory period

Figure 1 provides the total HV and total LV forecasts for the current 2019-24 period, actuals for FY20-22, and the most recent forecasts for FY23-24, as well as the forecast for the 2025-29 period.

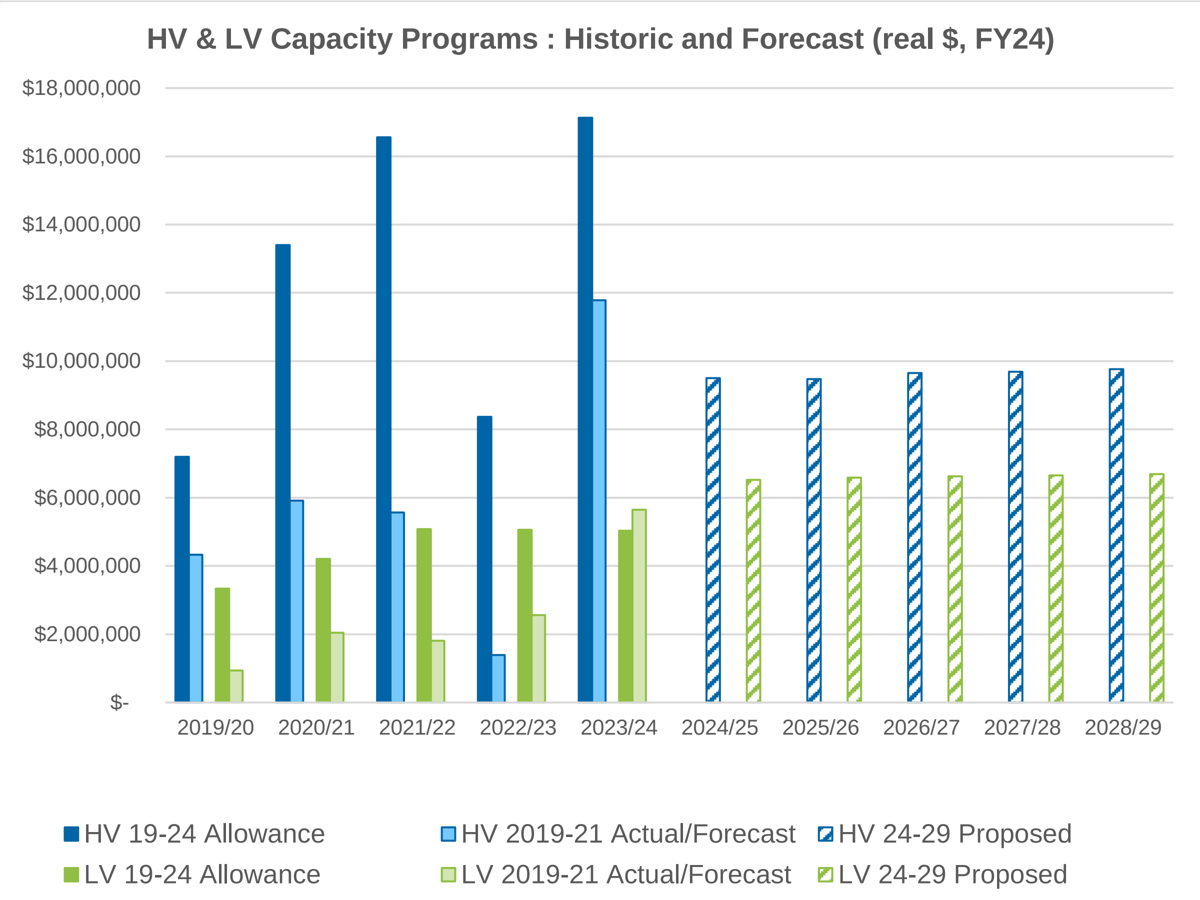

Figure 1 - HV & LV Capacity Program Expenditure

HV and LV programs are underspent over the FY19–24 period compared to allowance. This is partly due to lower than forecast demand growth reducing the emergence of risks on the HV and LV networks, but is primarily attributed to the need to deprioritise some HV and LV augmentation work for a period in order to respond to the issues below.

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Ausgrid paused all live work following a network fatality in 2019. More than 200 Live Work tasks were subsequently reviewed, and additional safety controls implemented where appropriate. Delivery of programmed work was also materially impacted by the recovery efforts from significant storm events in early 2020. These factors had a significant impact on the delivery of LV surveys for two years, which affected the identification of LV risks. It also led to a large backlog of other work with more immediate risks that took priority over HV & LV augmentation. COVID-19 related controls also significantly affected on Ausgrid's ability to plan and deliver work during this period.

HV & LV augmentation work was deprioritised more readily than other investment programs competing for the same resources during this period of constraint due to the nature of the risks it seeks to address as: a) there are relatively few safety risks associated with capacity and voltage compliance risks; and b) additional capacity risks can be carried for a short time as the dominant consequence is asset life reduction. Overall, deprioritising this type of augmentation is undesirable, but manageable over the short term, however it is not sustainable over longer periods.

A secondary impact of COVID-19 was a reduction in connection volumes and a change in customer usage patterns due to more flexible work arrangements.

1.6 Relationship with DER Integration Program

Ausgrid's DER Integration strategy and capex forecast is aligned with and compliments this LV forecasting methodology. Decisions in both programs are based on the same data sources with risks classified to ensure that they are assigned to the appropriate program.

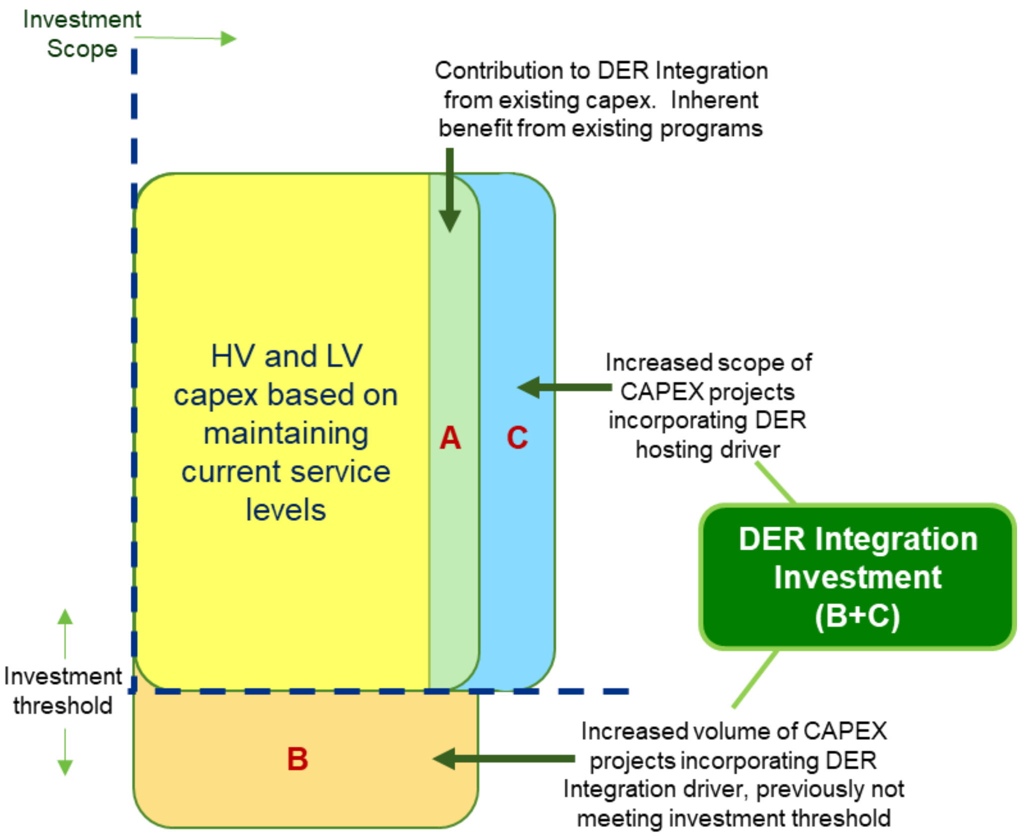

Figure 2: Relationship between Augmentation and DER Integration Programs

Figure 2 depicts the cross-over between the BAU LV and new DER Integration programs:

- The bulk of Ausgrid's HV & LV augmentation capex is addressed by the grey part of the chart and covered by the analysis set out in this document.
- Area A represents projects included in the forecasts for the LV program that are justified and included under the above standard capex approach, but which incidentally contribute to improving hosting capacity. These are included in our HV and LV augmentation capex.
- Area B represents capex projects initiated specifically to support DER, which are included in the forecasts for the DER Integration program.
- Area C represents projects within the LV program where the scope of work is increased to provide for DER. These projects are included in the forecasts for the DER Integration program

Where options address multiple drivers they are accounted for in the appropriate program based on the dominant driver. This discipline, combined with a 'side-by-side' review of the HV/LV and DER Integration programs has been conducted ensuring there are no double counts.

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2 HV Forecast methodology

The expenditure forecast for this program is derived by forecasting the expected network risk on each HV feeder, and then estimating the likely cost-effective investment to address that risk. The approach is summarised in **Figure 3**. The details of each stage in this process are outlined in the following sections.

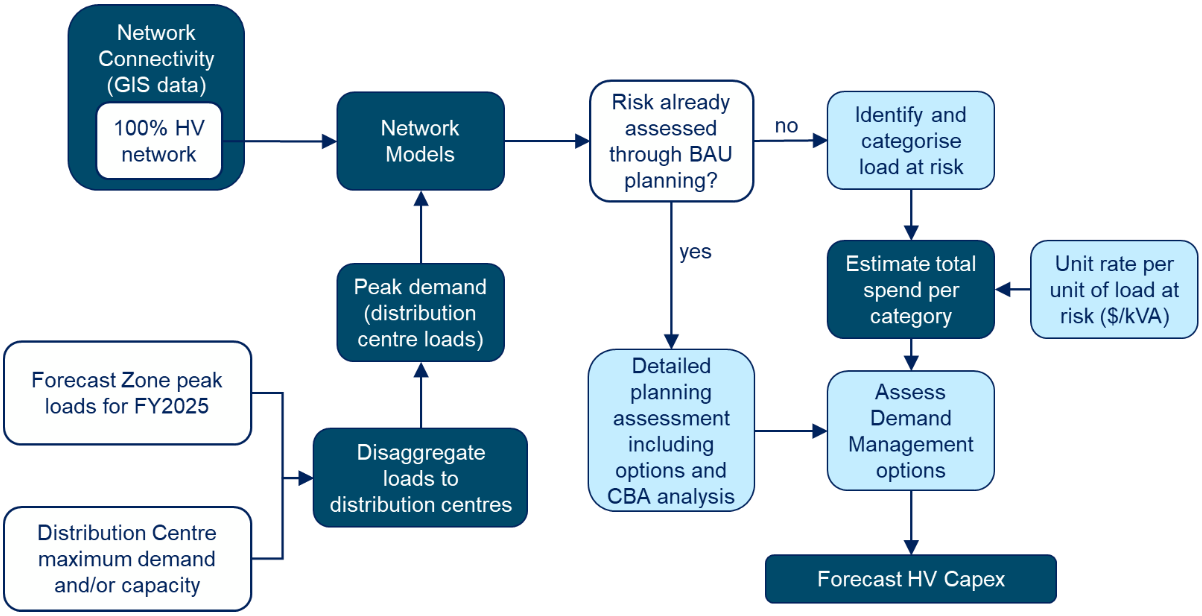

Figure 3: Overview of HV forecast methodology

A summary of the key parameters used to develop the HV programs is provided in **Table 2**.

Table 2: Summary of key parameters used to develop the HV programs

Program	Loads	GIS Date	Contingency	Conversion Factor	Project Type(s) and Valuation Approach
High Voltage	POE50* forecast for 2025 to determine peak for each Zone substation. Distribution Centre (**DC**) maximum demand or size are used to disaggregate the Zone forecast to each DC	March 2021	N	100%	A detailed estimate is used where available. Otherwise, a standard rate per unit of load at risk is applied.
			N-1	75%	

* 50% Probability of Exceedance

The HV network is modelled under both network normal and contingency conditions to identify risks.

Where there is an existing project in the capex pipeline to address an identified network risk, the actual forecast expenditure for that project in the forecast period is included in the investment forecast.

Identified risks without an existing project are assessed to determine the load at risk, and this risk is valued using an average cost-effective rate per unit of load to determine the likely investment required to address each risk. This is aggregated to estimate the total capex investment required. The average likelihood that a project will be deferred or avoided though demand management is also factored into the forecast. Finally, a CBA is completed at a program level, and the outcome is used to test the forecast assumptions.

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2.1 Peak Demand

The risks addressed by the HV program are generally associated with peak demand and therefore loading on the network. Peak loads are based on the POE50 Zone Forecast for 2025. Spot loads are excluded to ensure this analysis identifies only capacity shortfalls driven by underlying growth. Distribution centre maximum demand (where available) and size (otherwise), are used to disaggregate peak loads at the zone substation to each distribution centre.

2.2 Network Connectivity Models

The HV connectivity model is based on the system normal configuration from Ausgrid's corporate Geographical Information System (**GIS**), which includes all network elements (HV feeder sections, distribution substations and LV distributor elements). The GIS and connectivity model has 100% coverage of the HV network.

Identification of capacity shortfalls considers the 'system normal' configuration of the HV network as at March 2021. Rating information is sourced from the Ratings and Impedance Calculator (**RIC**) which uses manufacturers data and specific installation conditions to maximise the ratings achievable from the distribution equipment installed on Ausgrid's network. Among other factors, RIC considers short term and cyclic ratings of transformers and the impact of mutual heating on cables.

2.3 Identifying and Categorising Risks

Risks are identified by systematically assessing the network for capacity shortfalls through load flow analysis of both network normal and credible network abnormal configurations (credible contingency). In determining which configurations are considered credible contingencies, consideration is given to both the probability of that configuration occurring, and the scale of the impact if it occurs. The accuracy and availability of network data also bears on the evaluation of risk. In assessing risks for Ausgrid's HV programs, a credible 'network abnormal' configuration is the planned or unplanned loss of supply to a single HV feeder trunk or tee section.

Network risks include capacity shortfalls, voltage excursions outside of target range, and fault level issues. Screening criteria, informed by typical project types and unit rates, are used to identify thresholds where investment is likely to be cost-effective.

A capacity shortfall is expressed as the quantity of 'load at risk', expressed in kVA, that cannot be supplied under normal conditions, or within four hours of a fault occurring (to allow time to switch to a backup supply arrangement), without exceeding thermal ratings of equipment or resulting in unacceptable voltage excursions for customers.

HV risks are categorised based on whether they are a normal (**N**) state overload, or a contingent (**N-1**) state overload, by the network type (OH vs. UG, radial vs. interconnected), whether they supply a large load customer, or general network customers and by the magnitude of the issue.

2.4 Conversion Rates

Conversion rates reflect the probability that an identified risk will lead to a project. A comparison of conversion rates used in the 19-24 proposal compared to this 25-29 proposal is provided in **Table 3**.

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Table 3: Comparison of HV conversation rates between 19/24 and 25/29 periods

Program	Constraint Category	Conversion Rate 19-24	Conversion Rate 25-29
HV Capacity	N	100%	100%
	N-1	100%	75%

The lower conversion rate for N-1 constraints is due to the exclusion of risks associated with radial sections of the network (which will always fail N-1 assessments since they have no backup interconnections), and associated with sections of the network that supply large load customers (who, in accordance with Ausgrid's Connection Policy, fund the augmentations their connection requires).

2.5 Unit Rates

Historical project data combined with forecast cost inputs are used to develop unit rates. To forecast the capex required to address load at risk Ausgrid applies a threshold unit rate of $250/kVA (direct) to the capacity shortfalls. HV planning processes apply this same unit rate in cost benefit assessments to test whether proposed augmentation projects are prudent. This value is lower than the historical average of $404/kVA for projects that were initiated under the now revoked deterministic Schedule 1 of the Distribution Network Service Provider Licence Conditions. The reduction reflects Ausgrid's ability to choose to not proceed with the type of higher cost (and by inference lower benefit to cost ratio) projects which were mandatory under the previous licence standards. Application of the $250/kVA threshold cost ensures that future projects will provide a better cost benefit outcome than the previous historical average.

Where N issues and N-1 issues are identified on the same feeder, the unit rate for the N issue is reduced to reflect the likelihood of a combined solution addressing both N and N-1 issues.

2.6 Demand Management

The program volumes are adjusted to reflect the proportion of the program likely to be avoided or deferred due to demand management. Cost-benefit analysis of the demand management potential of projects identified in the HV program is undertaken, which accounts for the following factors:

- Differences in the cost and scale of HV program projects; and
- Differences in the mix of residential and business customers relevant to each HV program project.

The unit rates used for estimating demand management project costs have been informed by Demand Management Innovation Allowance trials and other demand management projects undertaken by Ausgrid, and comparison with demand management projects in other jurisdictions.

An overall demand management factor is derived, which estimates the share of overall HV program capital costs able to be deferred or avoided based on the cost-benefit analysis outlined above. For the demand management assessment of HV programs undertaken in 2021 this factor was 4%, with the same factor adopted for the FY25-29 forecast.

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2.7 Cost Benefit Analysis

Proposed investments in every program are subject to cost-benefit analysis following the principles set out in the Principles of Cost Benefit Analysis. Net Present Value (**NPV**) results in this paper are presented from a 'market' perspective, consistent with the National Electricity Rules (**NER**).

For assessment of the 11kV program, risks are grouped into A, B and C categories based on the magnitude of the risk ('A' representing the highest risk issues). This ensures investments to address these risks are prioritised appropriately within Ausgrid's overall project portfolio.

Table 4: Priority groupings used to evaluate CBA for the HV program

Priority	HV feeder criteria (individual feeder)	Average Load at Risk per feeder (Amps@11kV)	Average # of feeder segments with load at risk
A	Multiple instances of greater than 1MVA of unsupported load.	404	3.7
B	Single instance (and multiple instances where <25% urban load) of greater than 1MVA of unsupported load.	175	2.0
C	0.2MVA to 1MVA of unsupported load.	34.9	1.4

The investment forecast for each grouping of the program has been developed by estimating the costs and benefits of typical project types within the program and the volume of each type required over the forecast period.

The HV Capacity program CBA analysis uses Ausgrid's investment evaluation model and considers inputs including;

- Program cost;
- Network asset failure (and associated EUE); and
- Value of Customer Reliability (**VCR**).

Life reduction of HV assets running close to, or above, maximum operating temperatures due to overloading is not currently included as a factor in the cost benefit analysis; however, this approach may require review.

3 LV Forecast methodology

The expenditure forecast for these programs is derived from a bottom-up approach that estimates the network risk on each DC and LV distributor, and then estimates the likely cost-effective investment to address that risk. The approach is summarised in **Figure 4**, with details of each stage outlined in the following sections.

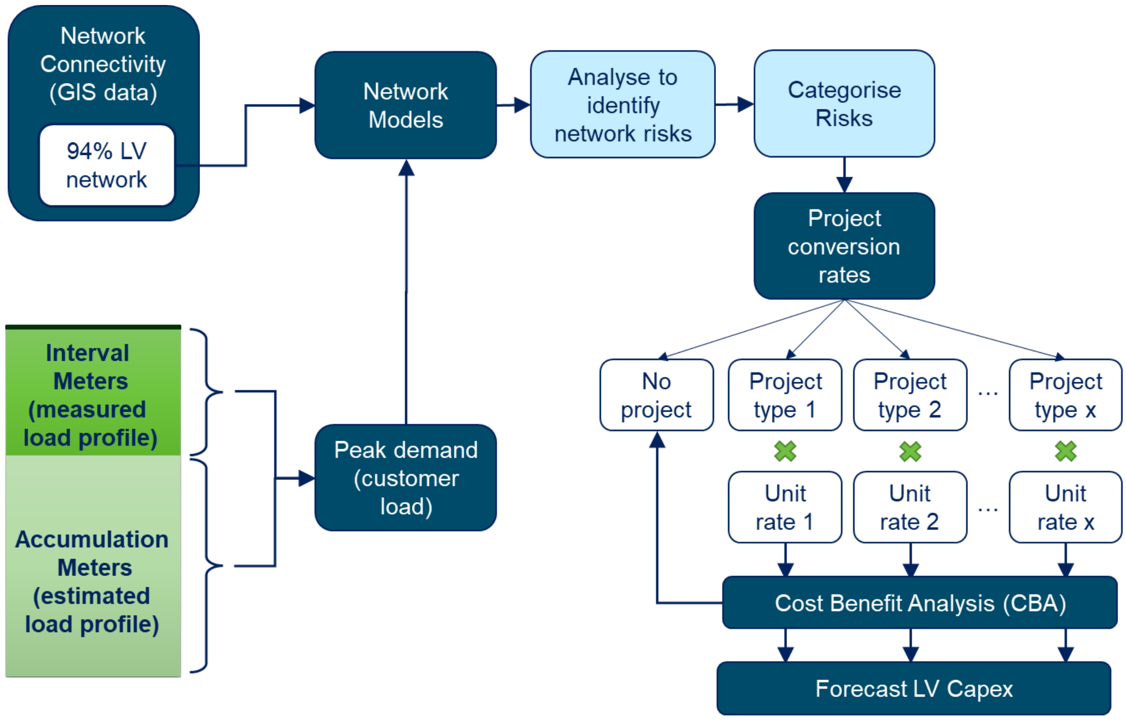

Figure 4: Overview of LV forecast methodology

A summary of the key parameters used to develop the LV programs is provided in the following **Table 5**.

Table 5: Summary of key parameters used to develop the LV programs

Program	Loads	GIS Date	Contingency	Conversion Factor	Project Type(s) and Valuation Approach
DC	Snapshot of LIS loads for each customer, taken at the time of peak for each distributor based on a 12-month period	May 2021	All elements in service (N conditions)	40%	Projects include new or upgraded mains and substations. Regional unit rates and historical project compositions are used to establish average unit rates for each region.
Fuse				50%	
Mains				10%	
Voltage				10%	

Risks are identified by modelling the LV network to identify elements that have a constraint. In practice some of these risks will be due to data errors and some will not prove cost effective to address. Ausgrid uses screening tests and conversion factors to estimate the number of risks that will have cost effective mitigation options.

Identified risks are categorised based on type and severity. The cost to address each categorised risk is estimated based on standard unit rates, leading to a proposed portfolio of projects required to address the risks, and an estimate of the associated investment. A CBA is completed at a program level, and the outcome is used to test the forecasting assumptions.

3.1 Peak Demand

The risks addressed by LV programs generally occur at periods of peak demand on the LV distributor or DC being considered. Peak demand was identified for each LV distributor based on customer load profile data over a 12-month period from 1 April 2020 to 31 March 2021. Individual customer load profiles were aggregated to find the load profiles on distributors and identify the time of maximum demand. Each LV distributor is modelled based on the allocation of customer demand at each supply point at the time of peak LV distributor demand.

Where available, interval and smart meter data at customer supply points is used to determine the customer load profiles. At time of analysis approximately 670k meters in Ausgrid's franchise area provide real interval data. For the remaining 1,150k accumulation meters Ausgrid's Load Information System (**LIS**) develops a profile using real interval data of comparable customers, which it identifies by comparing a range of metadata.

Using actual load profiles embeds the impact of diversity between load peaks and more accurately reflects the power flows on the distribution network. It also allows us to identify localised network risks that appear at particular times during the day (e.g. peak load due to commercial and industrial loads in the middle of the day versus evening peak due to residential demand).

Consideration is given to the influence of external factors on the forecast that would not be reflected by historical trends, such as customer response to new tariffs being introduced during the FY25-29 period. Given Ausgrid has interval meters and cost reflective tariffs (**CRT**) for over 35% of customers there is already significant CRT shaping demand behaviour. No further response to CRT has been applied to the LV augmentation needs.

For the FY25-29 regulatory cycle, the major external influences on demand relate to DER and associated tariffs and have been incorporated into the DER forecast and DER integration program rather than this underlying LV augmentation program.

3.2 Network Connectivity Models

The LV network connectivity model is based on the 'system normal' configuration from Ausgrid's corporate GIS. Ratings are based on typical ratings achieved for standard conductor and insulation types, and installation conditions.

GIS currently has 94% coverage of Ausgrid's LV network. The capex forecast is calculated for this 94% and extrapolated to provide an estimate for the remaining 6% of the LV network. Identification of capacity shortfalls considers the system normal configuration as at May 2021.

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3.3 Identifying and Categorising Risks

LV Network risks include capacity shortfalls, voltage excursions outside of target range, and fault level issues.

Ausgrid systematically assesses each network for capacity shortfalls via load flow analysis in network normal (N) configurations (i.e. all elements in service), then and applies thresholds and unit rates when identifying risks for each typical project type to screen for likely cost-effective mitigation investments. The process includes screening tests to identify likely data errors and excludes these from the results. LV risks under abnormal (N-1) network configurations are not considered as generally the value of the risk is less than the likely project cost.

Capacity risks are identified by comparing measured and modelled loads to the rating of each network element, and categorised based on the element type (fuse, busbar and mains). A utilisation threshold is used (90% for fuses and busbars, 100% for mains) to estimate the volume of capacity risks that will need to be addressed during the regulatory period. Assets loaded below these levels are not considered to pose a risk of overloading and are excluded from further consideration for the purposes of the forecast.

Voltage risks are based on the voltage drop along a distributor. A voltage risk is identified when the voltage drop on an element is greater than 15V. This limit is applied in a similar way to the utilisation thresholds above, as a screening test and indicator that voltage drop is likely to be exceeded with further load growth.

Fault loop impedance of the LV network is also analysed to identify network distributors where the thresholds in Ausgrid's network standards to maintain adequate protection are not met. There is a very high correlation between distributors with voltage issues and those with fault loop impedance issues.

There are 250 DC tap changes projected to be applied over the 2024-29 regulatory period that are required by Ausgrid's 230V migration program. These are included in the voltage investments component within the LV Distribution Capacity program. The volume is derived from the number of DC's currently operating with tap setting's several positions off nominal and where there is not expected to be opportunity for a tap change provided by other drivers.

3.4 Conversion Rates

Not all risks identified will require investment; for example, the risks may be associated with a temporary network state or an unlikely event, and therefore unlikely to recur. The conversion rates reflect the probability that an identified risk will lead to a project based on empirical data. A comparison of conversion rates used in the FY20-24 analysis compared to the current FY25–29 proposal is provided in the following **Table 6**, noting that the FY25-29 conversion rates are derived from more recent actual conversation rates.

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Table 6: Comparison of LV conversation rates between 19/24 and 25/29 periods

Program	Constraint Category	Conversion Rate 19–24	Conversion Rate 25–29
Distributor Capacity	Fuse Existing	40%	50%
	Fuse Future	25%	N/A*
	Mains Existing	20%	10%
	Mains Future	20%	N/A*
	Distributor Voltage	5%	10%
Distribution Centre Capacity	Existing	40%	40%
	Future	25%	N/A*

*In previous forecasts we used forecast growth rates to estimate a number of emerging risks in each area. In the current period, growth rates for most regions are moderate, and the growth is associated with uptake of DER, particularly electric vehicles. For this reason, we have forecast the growth in LV risks within the DER integration program.

Conversion rates for existing issues in all categories have been updated to reflect refinements in the screening process and increased confidence in data sources. The increase in the conversion rate for voltage investments to 10% reflects the increased number of projects that will pass a CBA test when fault loop impedance benefits are included in the project evaluation (noting the coincidence of voltage issues with high fault loop impedance).

3.5 Project Types and Unit Rates

Project complexity and scope, and hence unit rates, vary across the network depending on a range of factors: load density, geography, construction and configuration of the existing network, the types of customer served, etc.

LV investment is forecast in each network region (North, Central and South) by multiplying the expected number of risks in the region by a regional unit rate. The regional unit rate is a weighted average of unit rates for different project types in the region. The component unit rates and weighting factors are based on historical project data and cost forecasts.

3.6 LV Load Survey

The LV load survey takes load measurements to calibrate the LIS and to substantiate the identification of LV risks. It is expected that Ausgrid will conduct the same number of load surveys in the 24–29 period as was forecast in the current 19–24 period. Accordingly, a straight-line trend has been used to forecast the future requirements for this program. Note this program was underdelivered during the 19-24 period due to the sustained live work pause that prevented load surveys being completed.

3.7 Demand Management

For LV programs, deferral via reactive demand management is generally not cost effective.

3.8 Cost Benefit Analysis

Every program is subject to a cost-benefit analysis following the principles set out in the Principles of Cost Benefit Analysis for Network Investment. NPV results in this paper are presented from a market perspective, consistent with the National Electricity Rules (NER).

The investment forecast for each program has been developed by estimating the costs and benefits of typical project types within the program and the volume of each type required over the forecast period

The LV Capacity programs CBA analysis used Ausgrid's investment evaluation model and considered inputs including;

- Program cost;
- Network asset failure (and associated EUE); and
- Value of Customer Reliability (VCR).

Life reduction of LV assets running close to, or above, maximum operating temperatures due to overloading is not currently included as a factor in the cost benefit analysis; however, this approach may require review.

4 Expenditure Needs

The results of the HV and LV analysis and forecasting process are provided in the following sections. The forecast results are provided by regional area that align to Ausgrid's Area Plans. This breakdown supports use of the 11kV analysis for assessing load transfers between adjacent zone substations which are typically grouped within Area Plans.

4.1 High Voltage Capacity Program

Table 7 provides the forecast investment for the HV capacity program. The total forecast value excludes funding for risks that have projects currently in the delivery pipeline that are forecast to be delivered as part of the FY23 and FY24 delivery plans. **Table 9** contains the total capex forecast by area for the 24-29 regulatory period.

Table 7: HV results by Region

Region	Capacity shortfall (MVA)	Zones with shortfall	Forecast 24-29 (real $, FY24)
Chatswood	1.2	3	$3,789,792
Homebush	27.2	7	$8,728,844
Hornsby	0.9	2	$1,922,063
Lower Hunter	67.6	15	$20,491,120
Newcastle	7.7	6	$3,039,842
Oatley	0.6	1	$182,563
Ourimbah	14.0	9	$5,487,399
Upper Hunter	9.9	5	$2,982,205
Zetland	0.8	1	$1,467,592
Total	**129.7**	**49**	$48,091,420

The areas with the higher forecast expenditure broadly correlate with the localities with the most greenfield development (e.g. Maitland and Cessnock) or large scale redevelopment from low density to high density residential (e.g. Inner West Sydney, Canterbury Bankstown).

4.1.1 HV Program Cost Benefit Results

A summary of the results of the Cost Benefit Analysis for the HV program are provided in Table 10 below. All priority groupings resulted in a positive market NPV. Corresponding Value to Investment Ratios (**VIR**) are also shown, with a positive VIR also indicating a favourable cost benefit outcome.

Table 8: HV Program Investment Evaluation Total NPV Outcomes

HV Priority Group	Forecast Capex (real $, FY24)	NPV	VIR
A	$25,301,006	$186,253,615	3.86
B	$16,917,796	$40,865,405	1.27
C	$5,872,599	$6,172,815	0.55

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4.2 Low Voltage Capacity Programs

The forecast capex for the Low Voltage Capacity Programs, which address risks on Distribution Centres and LV Distributors, are provided in the following sections. The total number of risks identified that were evaluated by the screening process, and the final number of risks included in the forecast are summarised in **Table 9**.

Table 9: Identified and final LV capacity constraints

LV Capacity Constraints	Distribution Centre Capacity Constraint			Distributor Constraint					
	Existing	Future	Total DC	Existing Capacity		Future Capacity		Voltage	Total Distributor
				Fuse	Mains	Fuse	Mains		
Identified	273	593	866	456	844	867	2450	1767	7,795
Final	109.2	0	109.2	228	84.4	0	0	176.7	489.1
Conversion Rate	40%	0%	12.60%	50%	10%	0%	0%	10%	7%

4.2.1 LV Program Investment Evaluation Total NPV Outcomes

A summary of the results of the Cost Benefit Analysis for the HV program are provided in **Table 10**. All priority groupings resulted in a positive market NPV and VIR.

Table 10: LV Program Investment Evaluation Total NPV Outcomes

LV Group	Forecast Capex (real $, FY24)	NPV	VIR
Distribution Centre	$7,218,265	$12,533,486	0.81
DC Tap Change	$420,850	$3,517,320	3.88
Distributor Fuse	$9,596,926	$20,429,707	0.98
Distributor Mains	$4,616,399	$18,524,452	1.85
Distributor Voltage	$8,226,818	$7,077,881	0.40
Load Survey	$3,008,227	$5,512,959	0.77

4.2.2 Distribution Centre Capacity Program

From a total population of approximately 32,000 DCs, 866 DCs were identified with utilisation that exceeded the investigation threshold (comprising 273 existing constraints and 593 future constraints). It is projected that approximately 109 of these issues will require investment during the forecast period. This is shown in **Figure 5**.

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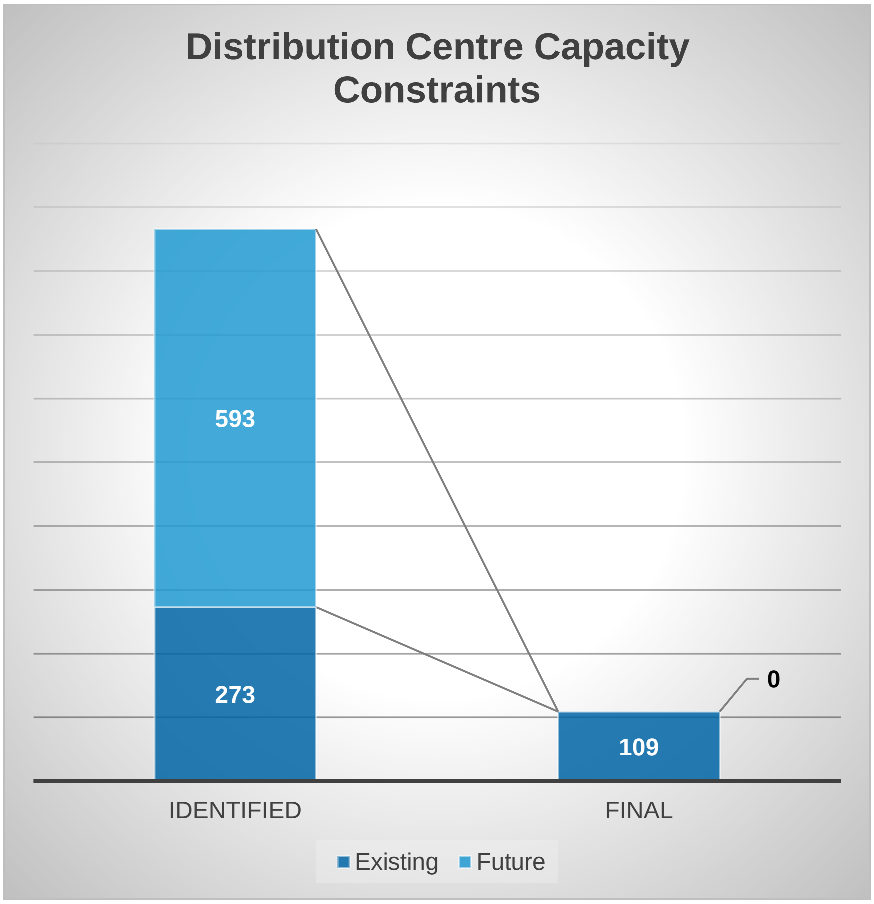

Figure 5: Risks above investigation threshold and projected risks expected to require investment in the forecast period

A breakdown of DC investment required for each region and separated into capacity risks and sites requiring a DC tap change (for voltage) are provided in **Table 11**.

Table 11: Distribution Centre results by Region

Region	DC Capacity Risks	Forecast (real $, FY24)	DC Tap Change	Forecast $ (real $, FY24)	Total Forecast (real $, FY24)
Chatswood	6.0	$622,882	30	$50,301	$673,183
Homebush	13.2	$1,432,387	24	$40,241	$1,472,628
Hornsby	2.8	$290,678	32	$53,654	$344,332
Lower Hunter	31.2	$1,036,908	56	$93,895	$1,130,802
Newcastle	11.6	$385,521	23	$38,564	$424,085
Oatley	4.0	$434,041	24	$40,241	$474,282
Ourimbah	15.6	$1,619,542	20	$33,534	$1,653,076
Upper Hunter	17.2	$571,627	6	$10,060	$581,687
Zetland	7.6	$824,678	36	$60,361	$885,039
Total	109.2	$7,218,265	251	$420,850	$7,639,115

***Note** DC Capacity risk volume is a product of initial identified risks and the conversion factors, which can result in non-whole numbers.

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4.2.3 LV Distributor Capacity Program

From a total population of over 65,000 LV Distributors, 6,384 were identified with utilisations that exceeded the investigation threshold (comprising 3,067 existing constraints and 3,317 future constraints). It is projected that 489 of these issues will require investment during the forecast period as show in **Figure 6**.

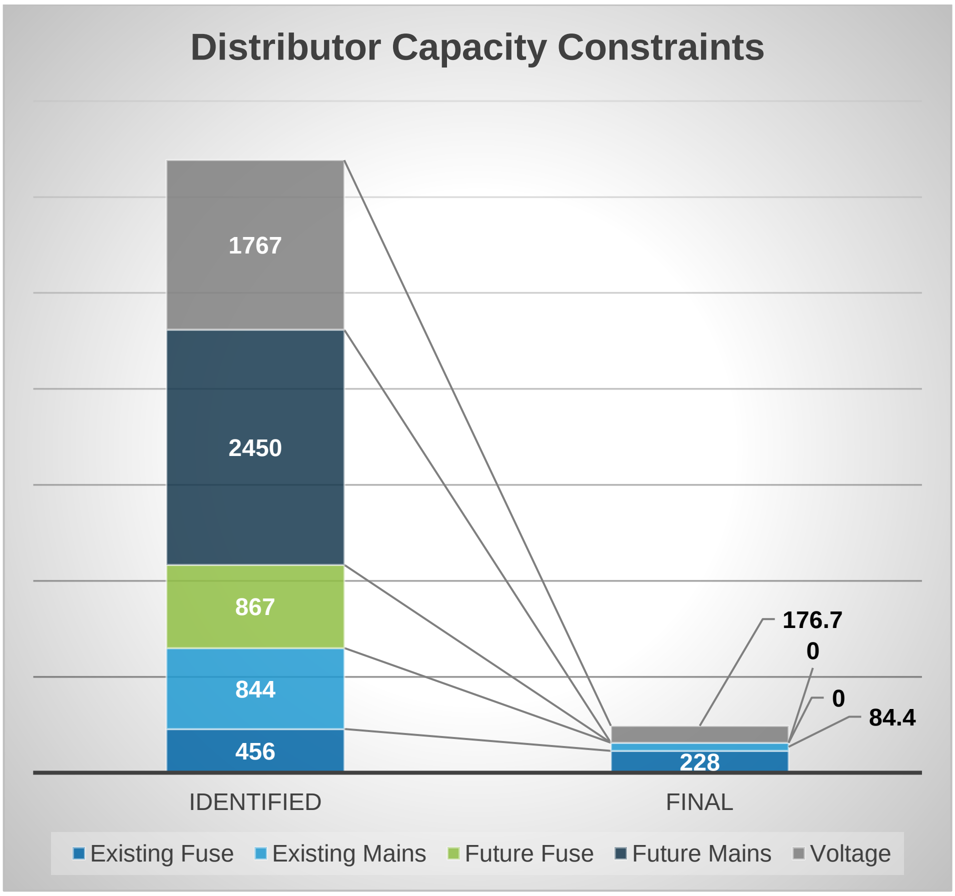

Figure 6: Distributor Capacity Risks above investigation threshold and projected risks expected to require investment in the forecast period

A breakdown of LV distributor investment required for each region is provided in Table 12

Table 12: Distributor Risks and Forecast Capex by Area Plan

Region	Fuse	Mains	Voltage	Total Risks	Forecast (real $, FY24)
Chatswood	18.0	11.9	27.2	57.1	$3,694,898
Homebush	20.5	13.2	33.1	66.8	$2,945,100
Hornsby	14.0	9.0	27.8	50.8	$3,264,005
Lower Hunter	54.5	14.4	26.2	95.1	$3,046,579
Newcastle	37.0	7.0	16.1	60.1	$1,763,726
Oatley	10.0	8.6	25.6	44.2	$2,006,455
Ourimbah	10.0	6.1	7.3	23.4	$1,832,687
Upper Hunter	10.5	2.0	1.8	14.3	$480,887
Zetland	53.5	12.2	11.6	77.3	$3,405,807
Total	228.0	84.4	176.7	489.1	$22,440,144

***Note 2** Distributor Capacity risk volume is a product of initial identified risks and the conversion factors which can result in non-whole numbers.

4.2.4 Total LV Capacity Program Results by area

A summary of the total capex for the DC and Distributor programs and the combined total per area are provided in **Table 13**. The subsequent charts provide number of risks and total investment per region respectively.

Table 13: Distributor and DC Forecast and total LV Capex by Area Plan

Region	Distributor Forecast Capex (real $, FY24)	Distribution Centre Forecast Capex (real $, FY24)	Total LV Capex (real $, FY24)
Chatswood	$3,694,898	$673,183	$4,368,081
Homebush	$2,945,100	$1,472,628	$4,417,728
Hornsby	$3,264,005	$344,332	$3,608,337
Lower Hunter	$3,046,579	$1,130,802	$4,177,381
Newcastle	$1,763,726	$424,085	$2,187,811
Oatley	$2,006,455	$474,282	$2,480,737
Ourimbah	$1,832,687	$1,653,076	$3,485,763
Upper Hunter	$480,887	$581,687	$1,062,574
Zetland	$3,405,807	$885,039	$4,290,846
TOTAL	$22,440,144	$7,639,115	$30,079,259

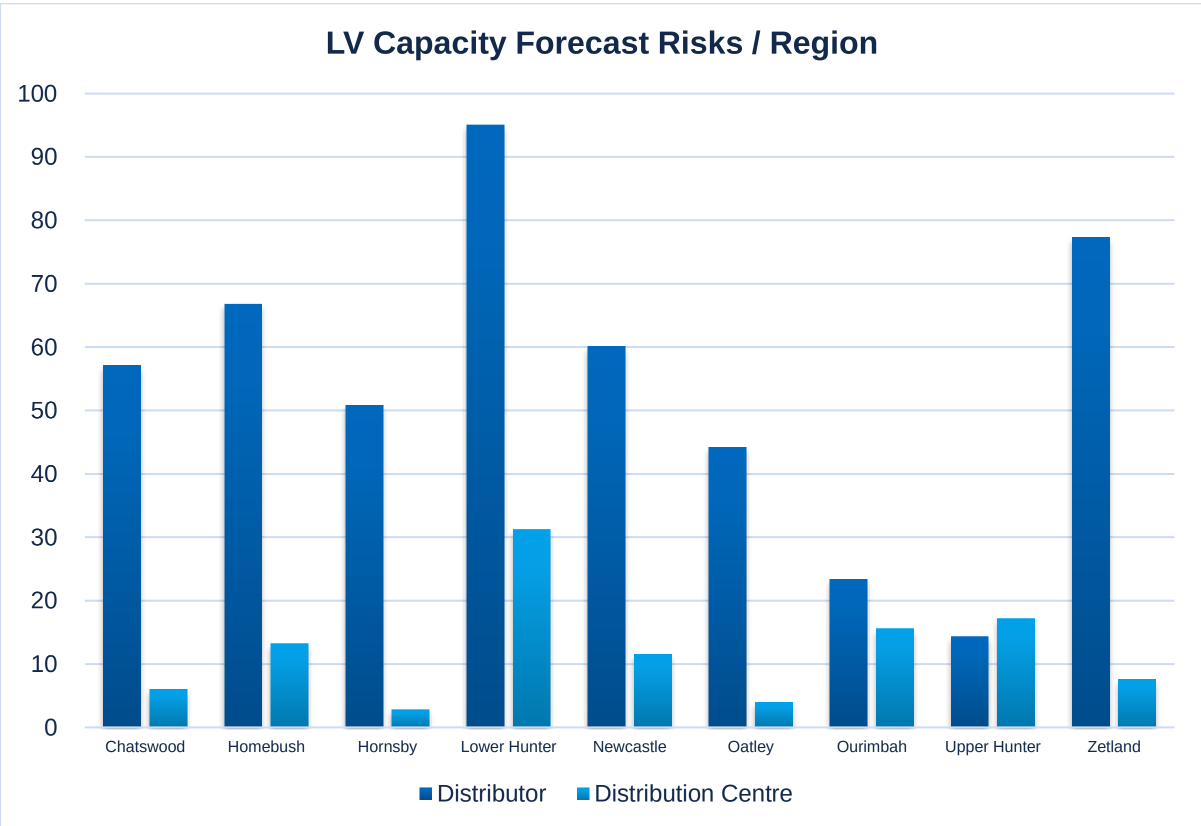

Figure 7: Breakdown of risks per area for the LV Distributor and DC programs

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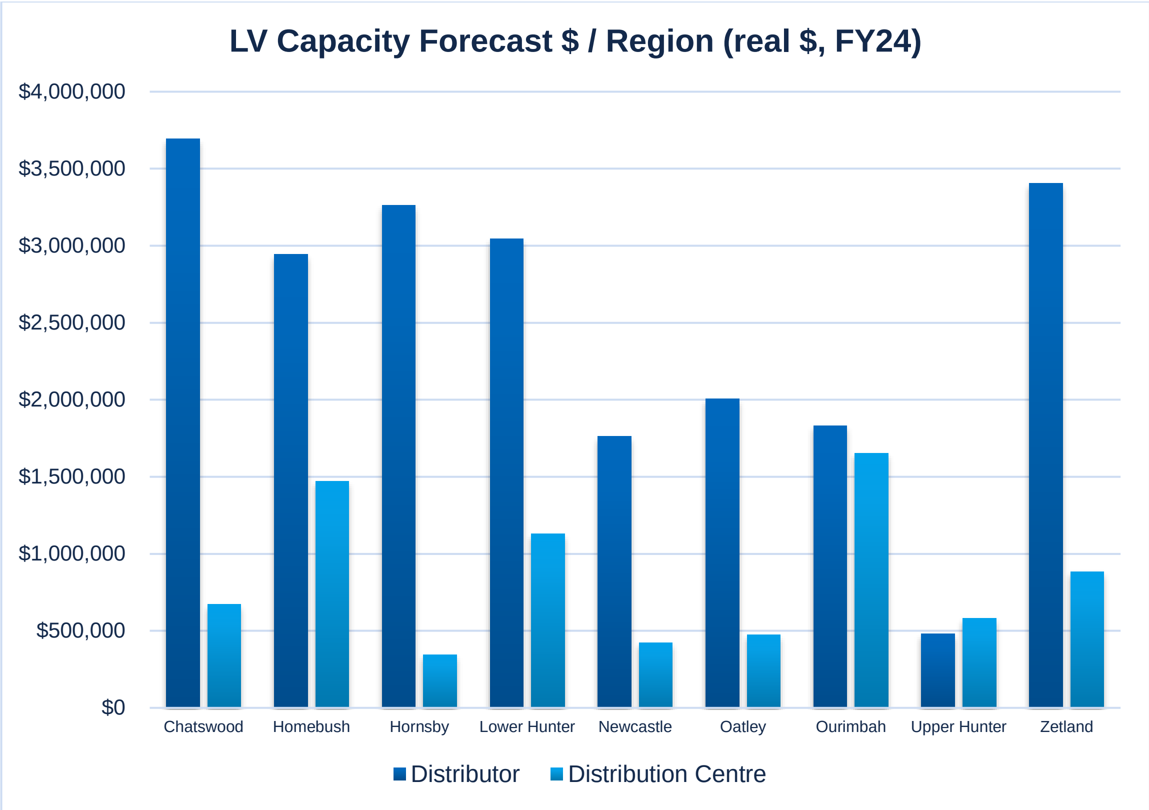

Figure 8: Breakdown of forecast capex per area for LV Distributor and DC programs

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