Downscaling – Electricity and gas distribution systems

19 April 2023

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The Net Zero Australia (NZAu) project is a collaborative partnership between the University of Melbourne, The University of Queensland, Princeton University and management consultancy Nous Group. The study examines pathways and detailed infrastructure requirements by which Australia can transition to net zero emissions, and be a major exporter of low emission energy and products.

Net Zero Australia

Downscaling – Electricity and gas distribution systems

Scenarios considered: Ref, E+, E−

19 April 2023

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1 Context and scope

1.1 Introduction

Electricity and gas distribution networks are responsible for the delivery of energy to residential and small commercial and industrial users. Distribution networks in 2020 supplied around 40% of the Australian domestic final energy demand. This may significantly change in the future as a result of fuel switching, integration of distributed energy resources and higher levels of flexible demand. Such factors, together with networks being capital-intensive and requiring long periods to justify new installations or augmentation, make distribution network planning an important exercise.

This document therefore describes the *Net Zero Australia* (NZAu) Project's projected changes in the electricity and gas network infrastructure necessary to support the Australian domestic net-zero energy transition, with a focus on the evolution over time of *capacities, regulatory assets* and *investments,* and how such figures differ across the NZAu study's 15 domestic regions.

1.2 Scope of this document

This document describes the background, methodology and outcomes of downscaling the electricity and gas distribution networks in the NZAu Project. The following are characterised and discussed:

- network capacity variations, investments and asset deployment/retirement which are needed to support the domestic net-zero energy transition;
- assignment of capital and distribution network assets to each modelling region; and
- subdivision of the investment required for asset expansion, phase-out and replacement, by region.

The differences in these investments over time and space are then examined for the different NZAu scenarios. The period 2020-2060 is considered for completeness, although full decarbonisation of the domestic energy sector is to be achieved by 2050. Results are compared with authoritative references, mostly from the Australian Energy Regulator (AER), to assess whether modelling assumptions and results are plausible.

2 Background

2.1 Electricity distribution network

Electricity accounts for roughly one fifth of all Australian energy consumption [1]. Electricity distribution networks (eDN) deliver electricity from terminal stations on the transmission network to both residential and commercial customers located within the distribution network. In Australia, eDNs operate between 66 kV-11 kV (sub-transmission) and 22 kV-240 V (distribution) levels with, respectively, looped and tree-shaped feeders and progressive voltage reduction. Electricity networks are dominated by capital costs and comprise up to 50% of the customers' final electricity bill [2]. This is because eDN consists of roughly 850,000 km of distribution lines in the National Energy Market (NEM), which compares to roughly 45,000 km of transmission lines [2].

The costs of the eDN are accounted for in NZAu's modelling with the Regional Investment and Operations (RIO) optimisation platform, based on current average eDN tariffs reported for individual distribution network system providers (DNSP) active in each NZAu region, with different values for residential, commercial, industrial and transport sector customers. These current tariffs are used in the modelling to set the 2020 annual distribution network revenue requirement, 60% of which is assumed to cover capital costs and 40% to cover O&M (and other) costs [3]. This revenue requirement is then scaled in the modelled years after 2020 with the capital component (in $) scaling linearly with the peak demand for each sector (residential, commercial, industrial, and transport) and with the O&M component remaining constant. This annual revenue requirement can be interpreted in the modelling as the electricity distribution cost to the various consumer types.

2.2 Gas distribution network

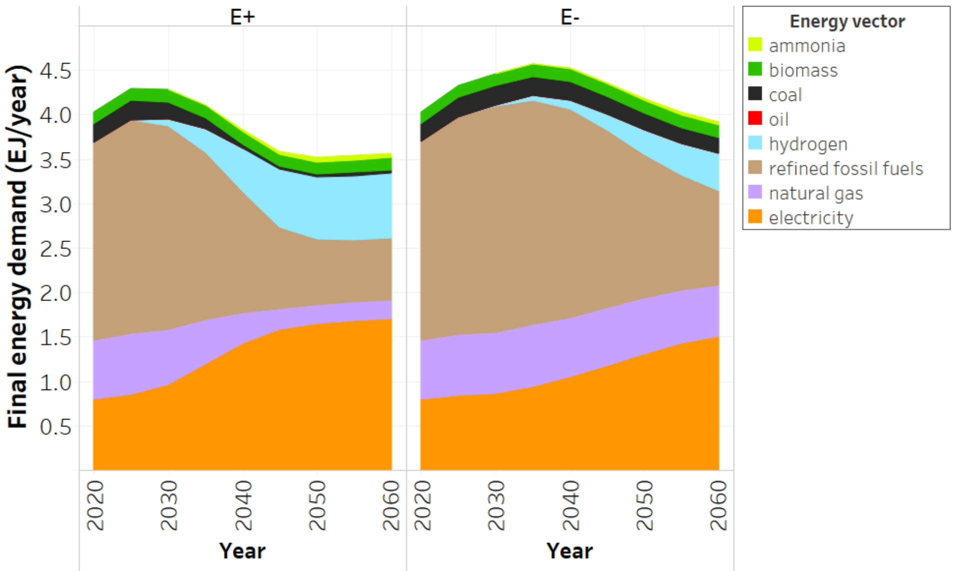
Natural gas represents around 22% of all Australian energy consumption [1]. Gas distribution networks (gDN) supply gas to 4.3 million households and 130,000 commercial and industry customers, with roughly 88,000 km of low-pressure networks operated below 10.5 bar [2]. Some states, and particularly Victoria, rely on gas significantly more than others, due to larger heating demand and historical resource availability. These existing networks may still be used in a low-carbon transition, for example, by blending hydrogen, biomethane or synthetic methane [4].

The gDN are modelled in the RIO optimisation platform by including their costs in the full cost of delivering fossil natural gas, biomethane or synthetic methane to different users. We have limited this modelling to these methane-rich fuels to avoid the challenges of modelling hydrogen blending in the gDN; a very complex task that is beyond the capabilities of the current study. The gDN costs assumed for industrial, commercial and residential customers were, respectively, 1.5 $/GJ, 7 $/GJ and 13.6 $/GJ [3], which represent a NEM-averaged value of the network tariff reported in the 'State of the Energy Market' report [2]. More information can be found in the NZAu MASS document [3].

3 Outputs of RIO to be downscaled

Figure 1 reports the domestic final energy demand by energy vector, as the aggregation of commercial, residential, industrial and transport energy use, and with the detailed final demand categories attributed to each vector listed in Table A.1. The overall share of energy delivered by distribution networks increases in aggregate, but with different trends across eDN and gDN, as well as across the two scenarios. electricity demand more than doubles between 2020 and 2050 in the E+ Scenario (a 107% increase by 2050), while it grows less in E− by assumption (a 65% increase by 2050). Conversely, the share of natural gas (including synthetic methane or biomethane) among the final energy vectors decreases in both scenarios, of course, especially in E+. Therefore, reliance on electricity increases during the low-carbon transition and this requires network extension/augmentation. At the same time, the overall use of gas diminishes with pipelines being less used and with the potential for stranding of gDN assets.

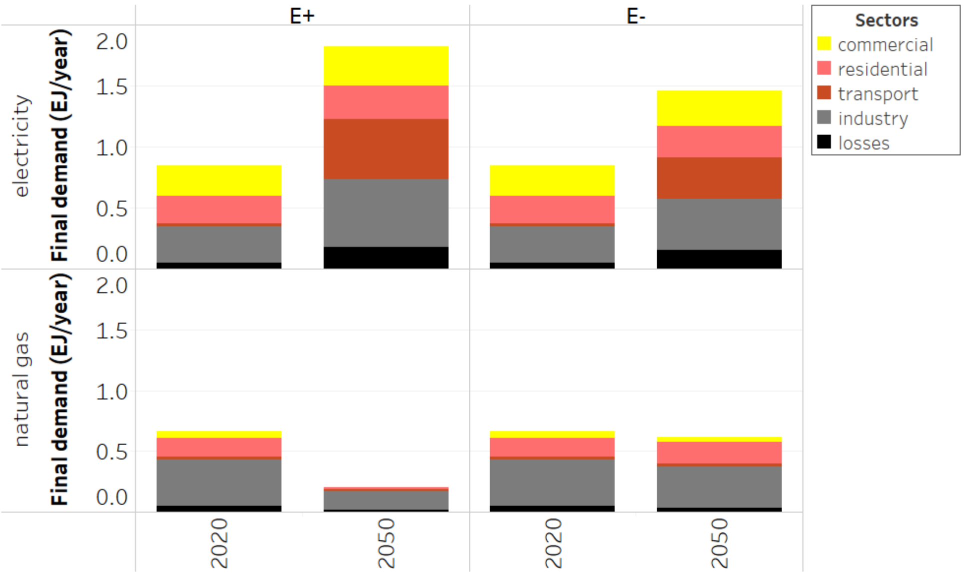
Figure 1 | Australian domestic final energy demand evolution between 2020 and 2050, by energy vector.



The sectors served by electricity and natural gas distribution networks are shown in Figure 2. Electricity is roughly equally split between commercial, industrial and residential sectors in 2020. In 2050, a major change comes from electrification of industry and the uptake of electric vehicles, especially for the E+ Scenario, in which the electricity demand from these two sectors altogether grows more than threefold, from ~0.3 EJ per annum, in 2020, to 1.1 EJ in 2050. The eDN therefore needs to accommodate this extra load. It is also noted that larger-scale processes like Haber-Bosch plants, steel/cement production facilities and industrial electrolysers were modelled as directly connected to the electricity transmission network, so the change in their energy demand does not feature in the eDN load.

In contrast, natural gas must be supplied by distribution network pipelines to provide heating in residential and commercial buildings, plus supplying various industrial processes. Gas use by 2050 is larger for the E− Scenario, where electrification is slower. Perhaps surprisingly, the E- Scenario finds a minor reduction in gas demand by 2050, inferring the continued importance of the gDN in this case.

Figure 2 | Final energy demand of domestic energy sectors served by electricity and natural gas, in 2020 and 2050.



4 Downscaling task

The detailed modelling of the eDN and gDN are very complex tasks that are beyond the scope of the Net Zero Australia project. As a result, the following assumptions have been made in the downscaling task:

- the electrical/natural gas peak load is a proxy for the associated distribution network capacity;
- the cost of distribution network per unit capacity remains constant;
- no distinction is made between individual DNSPs operating across the 15 domestic regions modelled in the NZAu Project; and
- the NZAu Project's 15 domestic regions are deemed as the suitable level of spatial granularity for the analysis. However, NSW-outback, QLD-outback, WA-north and WA-central were disregarded in this downscaling, as the very small and localised electricity and gas demand in these regions (see peak load values in Table 2, for a reference) are currently supplied by isolated microgrids and islandic networks.

The RIO results presented in Section 0 highlight significant changes in the demand that the eDN and gDN must supply. These do not only change over time, but are also strongly influenced by the transition pathway in the E+ and E− Scenarios. As investment in the distribution network involves extension and replacement of older assets, these will also vary over time and depend on the transition pathway. To investigate these aspects, the following downscaling steps were undertaken for the NZAu Project's 15 domestic regions:

1. the energy handled by the distribution network 2020 is evaluated;
2. the hourly peak load for each year is then evaluated;
3. the yearly revenue to distribution network system operators in 2020 is evaluated using the energy delivered to customers;
4. the distribution network Regulatory Asset Base (RAB) in 2020 and gross asset value per unit capacity are evaluated; and
5. finally, the distribution network asset evolution and associated investment breakdown into infrastructure renewal, augmentation/expansion and stranded assets is evaluated over time.

Results for each of the NZAu Project's 15 regions are then presented and discussed.

4.1 Evaluation of yearly energy

From the RIO outputs, the *final energy demand* for the residential, commercial, industrial and transport sectors was considered, and decomposed into the demand supplied, respectively, by electricity and natural gas, the latter potentially including synthetic methane if this is economic. Large industrial electrolysers and gasification plants were modelled as transmission-connected and therefore do not affect the energy handled by the distribution network [3]. It is also worth noting that the transport sector demand is only relevant to the eDN through electric vehicle charging points, which will comprise some combination of private residential, workplace and public locations. On top of the final energy demand, an energy conversion loss factor and a correction factor for upstream losses were included with respective values of 4% and 2% for eDN, and both 3% for gDN [3], following previous work [5].

4.2 Evaluation of the yearly peak load

The allocation of costs in the distribution network is roughly proportional to the capacity that it must handle during the year [2]. Hence, extraction of electricity and gas hourly peak loads from the RIO output is crucial to the distribution network downscaling. The aggregated hourly modelled load of each of the residential, commercial, industrial and transport sectors was evaluated for each modelled year (every 5 years), and linearly interpolated across each of the intermediate years. Peak load values were assumed to be directly proportional to the distribution network installed capacity. Given this, our modelling includes a component of flexible load (e.g. domestic hot water or light- and medium-duty electric vehicle charging) that the hourly energy supply-side optimisation can shift over time to alleviate network congestion (reduce peak loads and consequently DN costs), while incurring a small opportunity cost associated with diverging from typical consumption patterns [3]. The modelling is therefore able to optimise between distribution network augmentation costs and the dispatch of some flexible loads.

4.3 Evaluation of distribution network revenue in 2020

The distribution network revenue requirement by state in the initial modelling timestep (2020) was computed based on the final energy volume delivered to the customers of various types (i.e. not including losses) and their associated tariff. For residential energy delivery, this tariff is considered to be the component of electricity and gas bills that is charged to residential consumers to cover distribution costs, as reported by the Australian Energy Market Commission (AEMC) [6] for electricity and in the Gas Price Trends Review [7] for gas. Values retrieved from these reports are reported in Table 1. Average values were assumed for NT (eDN and gDN) and WA (eDN only). For consumers in other sectors, electricity distribution costs of 6.7, 4.8 and 8.6 cent/kWh were assumed for the commercial, industrial and transport sectors, respectively, as discussed in the MASS document [3]; values are 2.52, 0.5 and 4.99 cent/kWh for gas distribution. The revenue requirements for 2020 were then used to estimate the RAB value for the distribution networks by considering their 2020 revenue requirement as a single annuity and a 40-year network lifetime [8].

Table 1 | Distribution network tariffs for residential customers by state; used for the validation of the estimated RAB.

State	eDN tariff [cent/kWh]	gDN tariff [cent/kWh]	Notes
NSW	10.5	1.39	
NT	9.39	1.84	average eDN and gDN
QLD	8.18	3.78	
SA	12.33	2.48	
TAS	7.12	1.19	
VIC	8.66	0.62	
WA	9.39	1.6	average eDN

4.4 Estimation of the distribution network RAB in 2020

Electricity distribution network RAB in 2020 was determined using the aggregated opening value of 78.8 B$ which is sum of opening values reported by DNSPs in all states/territories except for WA. This opening RAB value was then adjusted to include the contribution of Western Australia and then apportioned to the 15 individual regions modelled in NZAu Project, based on their respective peak electricity demands in 2020.

Equivalent analysis was carried out for gas distribution networks, whose 2020 RAB was 10.5 B$, excluding WA (regulated by the Economic Regulation Authority) and NT [2]. This time, the yearly energy demand of individual NZAu region was used in place of peak demand to downscale the RAB, which reflects the common practice of using gas linepack to operate gas distribution networks.

As a benchmark, RAB estimation based on the expected eDN and gDN revenues in 2020 was also pursued, following the methodology adopted by the prior Net Zero America Project [8]. The underlying assumption was that distribution network revenues should ultimately make up for asset depreciation and the agreed return on capital plus taxation and operating costs. Only the distribution network revenue share, α_{DN}, for the return on capital and asset depreciation contributions was considered, given these two cash flows are proportional to the RAB. Respectively, their share amounts to 42% plus 18% of the DNSP revenues for eDN, and 36% plus 18% for gDN [2]. A capital recovery factor (CRF) for an average asset residual life N of 20 years (half a 40 year asset lifetime L [3]) and an interest rate, r, equating the WACC of 4.7% [3] was considered to divide the annual capital recovery ($\alpha_{DN} \cdot Rev_{DN,y}$) and obtain the gross value of distribution network assets:

$$RAB = \frac{\alpha_{DN} \cdot Rev_{DN,y}}{CRF}$$

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Finally, the asset value per unit distribution network capacity was computed for year 2020.

Deviation between the two methods of estimating the RAB for different regions were found to be in the range 4% to 33 % for eDN, which is reasonable, considering the range of energy tariffs available to end customers and the averaging performed across regions and states. For gDN, an even fuzzier picture emerges from the wide range of tariffs and regulatory frameworks applied to pipelines across Australia (e.g. full, light and part 23 regulation [2]). As a consequence, deviations observed in the RAB estimated by the two methods vary for different regions in the range -5% to 91%. Given these considerations, RAB figures reported by DNSPs were the preferred source of initial (2020) eDN and g DN RAB estimates.

4.5 Estimation of distribution network assets evolution over time

In line with the methodology used by AER, RAB evolution over time was broken down into renewed and new assets, depreciation and stranded assets. However, we do not account for inflation, as all financial figures of this analysis are expressed in 2020 Australian dollars.

The value of new assets, NA_y, is directly proportional to the variation in the peak load. This variation was evaluated in 5-year periods in RIO, and linearly interpolated for each intermediate year for downscaling purposes. This way, the value of new assets (which is a measure of network augmentation) is the difference between the estimated RAB at the end and the beginning of each year, computed in each region assuming a constant DN revenue requirement per unit of network capacity, which is based on the RAB figures reported by DNSPs in 2020, as discussed in Section 4.4.

$$NA_y = RAB_y - RAB_{y-1}$$

So, the value for the 2020 RAB was scaled up to the whole Australia and apportioned to each NZAu region based on the respective peak demand on eDN.

The calculation of the value of renewed assets assumed a uniform age distribution of the distribution network. This average age value, $\bar{A}_y$ was set to 20 years in 2020 (which entails a 5% renewal rate every year) and was subsequently tracked over time based on the computed value of network infrastructure addition:

$$\bar{A}_y = \frac{(\bar{A}_{y-1} + 1)(RAB_y - D_y) + 0(NA_y + RA_y)}{RAB_y - D_y + NA_y + RA_y - SA_y}$$

where NA_y, RA_y, SA_y and D_y represent the RAB variation at the end of year y in the form of, respectively, new assets, renewed assets, stranded assets and depreciation of existing assets. As the network average age evolves, so does also the renewal rate, which enabled evaluation of the renewed assets each year as the product between the current RAB and the renewal rate value, RR_y:

$$RA_y = RAB_y \cdot RR_y$$

Knowledge of the average asset life and its evolution over time also enabled estimating the linear RAB reduction due to asset depreciation as the ratio of the current network RAB and its average remaining life ($N_y = L - \bar{A}_y$), where L is the assumed network lifetime of 40 years:

$$D_y = \frac{RAB_y}{N_y}$$

There may also be years when the distribution network peak load decreases – hence highlighting a "negative" asset growth rate. In such cases, no new assets are deployed ($NA_y = 0$). Additionally, a lower renewal rate is assumed down to 0% and such that:

$$RA_y = \left| min\left\{0;\ |RA_y - RA_{y-1}| - \frac{RAB_y}{N_y}\right\}\right|$$

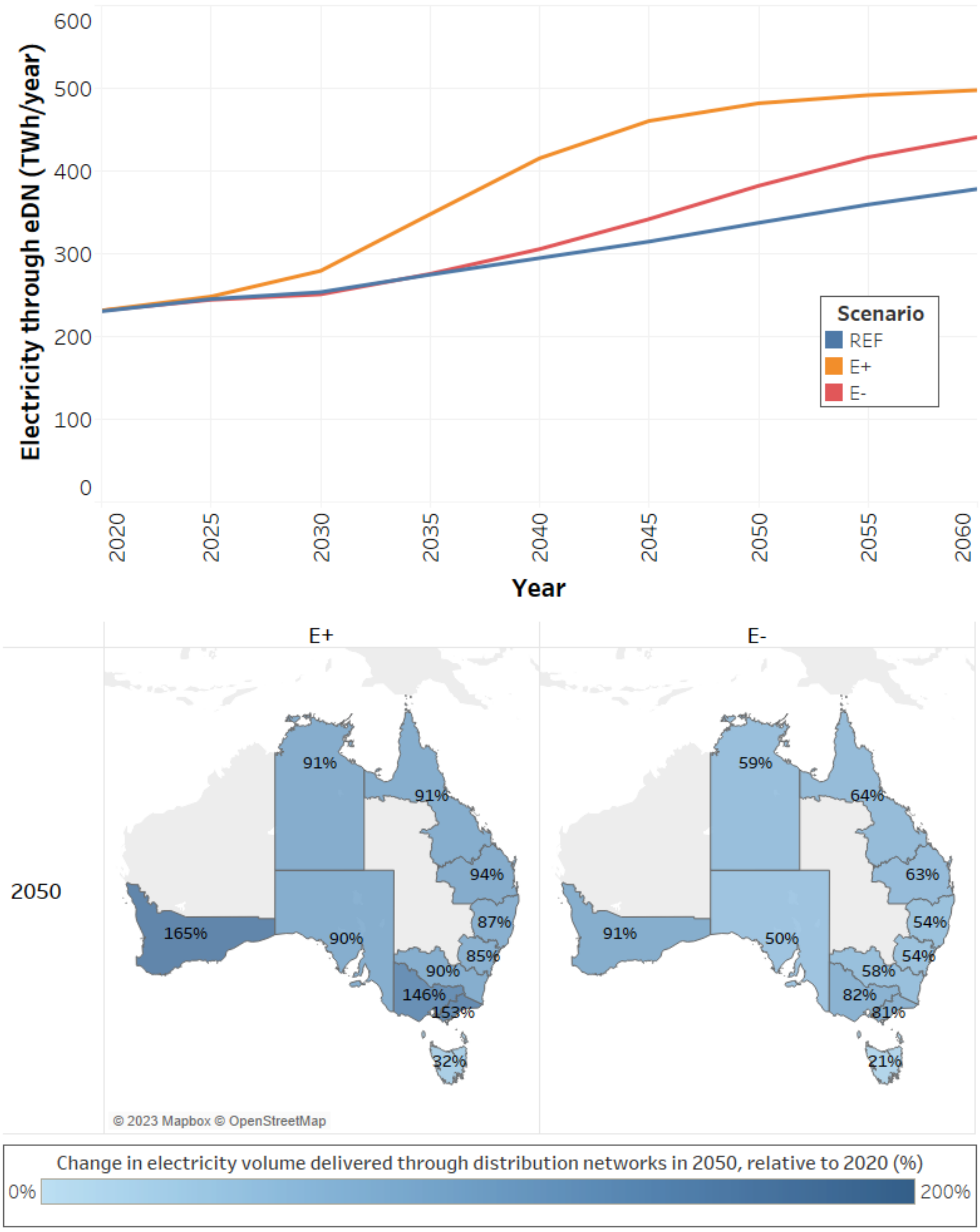
From the equation above, the difference between the absolute value of the network contraction $|RA_y - RA_{y-1}|$, and the predicted renewal rate based on asset aging, $\frac{RAB_y}{N_y}$, represents the portion of distribution network that should be retired prior to reaching its end of life. Positive values of this difference were accounted for as stranded assets.

5 Results

5.1 Electricity distribution network

The energy volume to be served by eDN evolves over time and space as presented in Figure 3.

Figure 3 | Time and space evolution of electricity demand to be served by electricity distribution networks.



Electrification of the building and transport sectors translates into higher annual electricity demand for all net-zero scenarios, as compared to the reference case, REF. For the E+ Scenario, the volume of electricity delivered through the eDNs more than doubles between 2020 and 2050, from 230 to 482 TWh/year. While this is a similar trend to the increase in final energy demand (Figure 1), the extent to which the electricity demand increase translates into larger eDN capacity depends ultimately on the hourly load profile of different sectors, as well as the associated seasonal variation.

Table 2 reports for each modelled region the peak electricity load resulting from the aggregation of residential, commercial, industrial and transport electricity sectoral demand profiles across the years modelled. Values in Table 2 are not to be confused with the sum of distribution substation capacities, whose ratio over the peak demand to be served greatly varies across states and determines the eDN hosting capacity [2]. Lower eDN hosting capacity is needed when load flexibility can be exploited by shifting in time some of the electricity demand, thus reducing the need for expensive infrastructure. The NZAu Project includes these effects by treating residential hot water or electric vehicle charging as flexible loads. Figures from Table 2 were then used as a proxy for tracking the evolution of the installed capacity of the eDN over time. Note this is a reasonable assumption since the hosting capacity reported by several distribution network system providers did not show any consistent change over the last decade [9]. Large industrial loads such as gasification and reforming processes, electrolysers and pumped hydro storage are modelled as connected to the transmission network and therefore do not impact the distribution network requirements.

Table 2 | Peak electricity load [GW] on the distribution network by region; E+ Scenario.

Model region	2020	2025	2030	2035	2040	2045	2050	2055	2060
NSW-central	9.9	10.5	11.2	12.7	15.0	16.5	17.2	17.4	17.5
NSW -north	1.6	1.7	1.8	2.1	2.5	2.7	2.8	2.9	2.9
NSW -outback*	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
NSW -south	1.4	1.5	1.6	1.8	2.2	2.4	2.5	2.6	2.6
NT	0.7	0.8	0.9	1.0	1.1	1.3	1.3	1.3	1.4
QLD-north	1.7	1.9	2.0	2.3	2.8	3.0	3.2	3.3	3.3
QLD-outback*	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
QLD-south	7.5	8.0	8.8	9.9	12.2	13.5	14.2	14.4	14.6
SA	3.0	3.2	3.4	4.1	4.6	5.0	5.1	5.2	5.3
TAS	1.6	1.7	1.7	1.9	2.0	2.0	2.1	2.1	2.0
VIC-east	0.4	0.5	0.6	0.7	0.9	1.0	1.0	1.1	1.1
VIC-west	8.7	9.7	11.2	14.2	17.3	19.7	20.9	21.5	21.9
WA-central*	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
WA-north*	0.3	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.6
WA-south	5.9	6.1	7.5	9.6	11.8	13.5	14.2	14.6	14.8
AUS	**43.1**	**46.1**	**51.3**	**60.9**	**73.3**	**81.7**	**85.6**	**87.3**	**88.4**

* These regions were included in the table for completeness, and only as a reference of their marginal current and future values of peak load; however, they were not included in the calculations of this downscaling task.

Table 2 shows that the eDN capacity required to handle the modelled peak loads grows quickly in the upcoming years. This is particularly the case for the E+ Scenario where electrification is strong. It should however be noted that the peak load on the electricity distribution network increases at a slower rate than the installed electricity generation capacity because the average capacity factor decreases with higher renewable penetration.

Another consideration is eDN must also accommodate the injection of distributed generation at any point in time. Particularly given the large projected uptake of rooftop PV, it may be the case the electricity fed into the grid is larger than domestic demand, in which case the determinant of distribution network capacity at substations should be the peak electricity generation from distributed resources, and not the peak load anymore. NZAu results for the E+ Scenario show this is not the case even in 2060. However, hourly rooftop PV generation is nonetheless just below peak load values. With lower load electrification in the E− Scenario, times with higher rooftop PV generation than domestic peak loads are likely to arise. This does not affect the downscaling assumption as behind-the-meter battery deployment alongside PV installations will mitigate the grid-injected generation values. Nonetheless, these results underscore how in the future eDN must be able to accommodate an almost fully reversed electricity flow between periods of high and low solar generation: a challenging operational task indeed.

The estimated RAB in 2020 for each of the 15 NZAu modelled regions is reported in Table 3. We note once more that a number of the modelled regions have very small electricity loads and are not actually served by existing regulated distribution network service providers, namely NSW-outback, QLD-outback, WA-central, WA-north. In these regions smaller the smaller electricity demand is served by small-scale generation and local electricity networks. Hence, we decided not to include these regions in the analysis here.

Table 3 | Estimation of regulatory asset base in eDN, in year 2020.

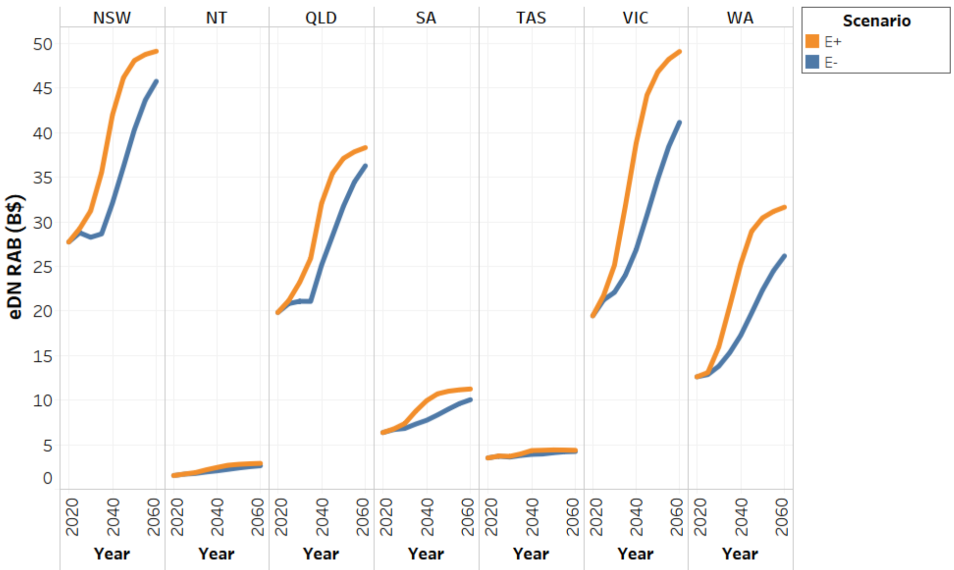
Model region	DN tariff [c/kWh]	En volume [TWh]	eDN revenue requirement [M$]	eDN RAB [M$]	eDN RAB [$/kW]
NSW-central	10.5	51.9	3,789	21,229	2015
NSW-north	10.5	8.5	634	3,475	2015
NSW-south	10.5	7.4	560	3,021	2015
NT	9.39	3.4	224	1,539	2015
QLD-north	8.18	9.3	612	3,714	2015
QLD-south	8.18	40.5	2,584	16,110	2015
SA	12.33	13.7	1,093	6,358	2015
TAS	7.12	10.0	572	3,511	2015
VIC-east	8.66	2.1	143	910	2015
VIC-west	8.66	42.4	2,926	18,539	2015
WA-south	9.39	28.7	1,757	12,611	2015

The national peak demand and RAB evolution over the years is reported in Table 4, while Figure 4 shows the state-by-state detail. These demonstrate the link between the degree of demand-side electrification and value of eDN assets, with the rate of increase in the national eDN RAB greatest during the years 2030 to 2040, when the sales of electric vehicles and heat pumps for space heating become predominant in E+. In E-, the rate of asset addition is slower, following the slower electrification pace. When considering the yearly asset expansion rates and comparing them with the 1.6% reported by AER for year 2020, results show the eDN transition may entail 2-3 times the expansion rates that are currently being experienced. Under our assumptions, the RAB is proportional to peak electricity load. However, it is also possible that the effect of learning and the effective integration of distributed energy resources, above the present assumptions of flexible water heating and electric vehicle charging, could reduce the asset requirement per unit capacity, thus reducing the extent of network expansion required.

Table 4 | Australian peak eDN demand and evolution of regulatory asset base modelled in the E+ and E− scenarios.

	E+			E-		
Year	Peak load [GW]	eDN RAB [B$]	Yearly expansion [%]	Peak load [GW]	eDN RAB [B$]	Yearly expansion [%]
2020	45.7	91.0	1.4%	45.7	91.0	1.0%
2025	48.9	97.4	2.3%	48.1	95.8	0.3%
2030	54.5	108.4	3.7%	48.9	97.4	1.0%
2035	64.6	128.6	4.1%	51.3	102.1	2.6%
2040	77.8	154.9	2.3%	57.8	115.1	2.5%
2045	86.7	172.5	0.9%	65.1	129.6	2.3%
2050	90.8	180.6	0.4%	72.7	144.7	1.8%
2055	92.6	184.4	0.2%	79.1	157.4	1.1%
2060	93.8	186.7	-	83.5	166.2	-

Figure 4 | Regulatory asset base evolution in the eDN between 2020 and 2060, by state.



The projected eDN investment of various types over time and by state is reported in Figure 5, for the E+ Scenario, and the E− Scenario. For the E+ Scenario, investments are initially split between new assets and existing infrastructure renewal. In the second half of the period explored, investments are mostly needed for replacing existing infrastructure and do not translate into a increase of the eDN RAB. In some regions, the required infrastructural needs even start diminishing, which means only a portion of the infrastructure reaching its end of life in these later years have to be renewed. However, absence of network additions and lower renewal rates are small, suggesting that stranding of existing eDN assets is unlikely; an unsurprising result given the importance of electricity networks in Australia's decarbonisation. Indeed, network investment are consistently needed over time for all the modelled regions. Figure 6 gives a glimpse of the NZAu regions where investments in the eDN are most prominent.

Figure 5 | Renewed, new and stranded asset annual investment and resulting evolution of the electricity distribution network RAB, aggregated for each modelled state/territory, and for the E+ and E– Scenarios.

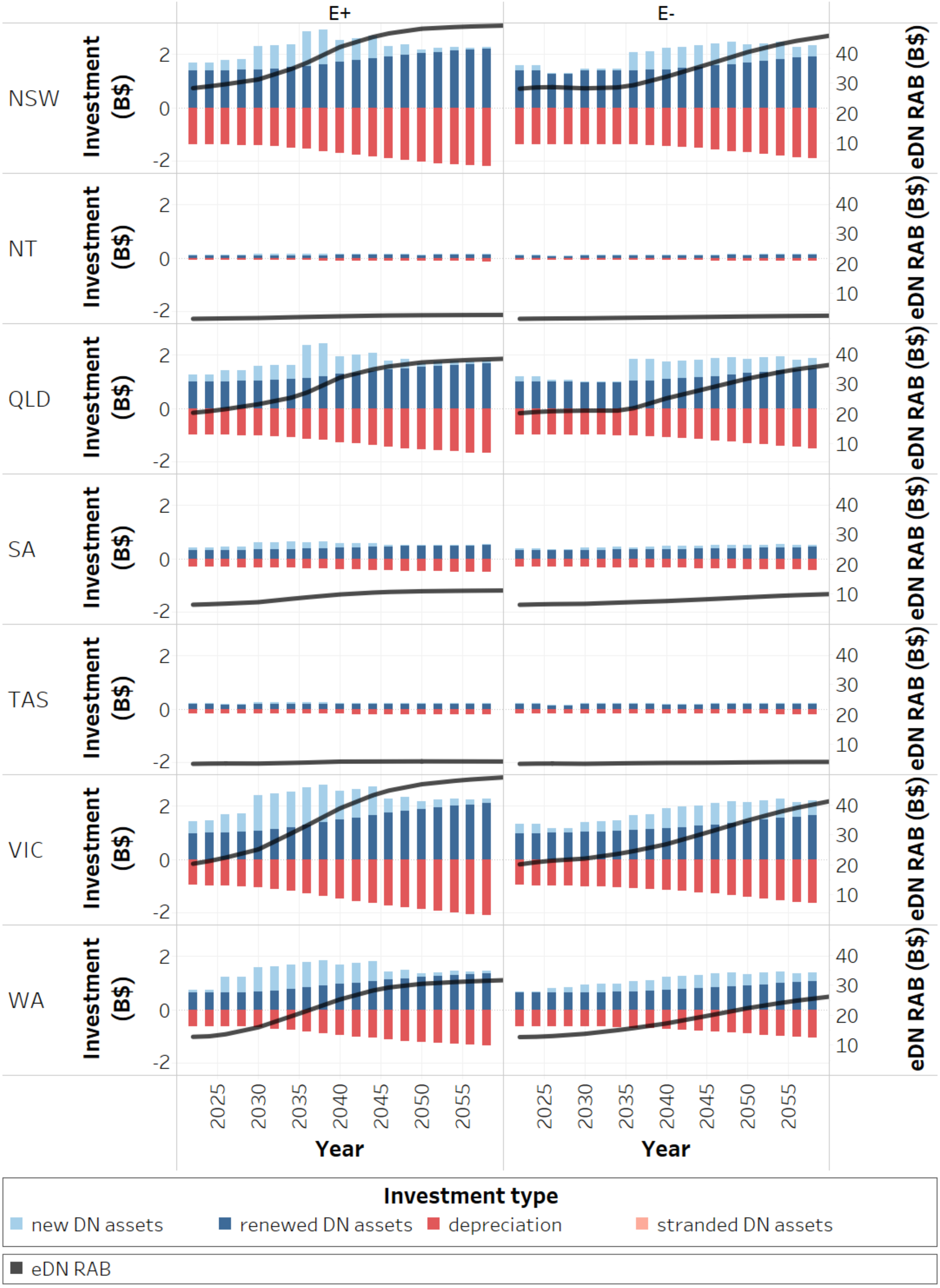
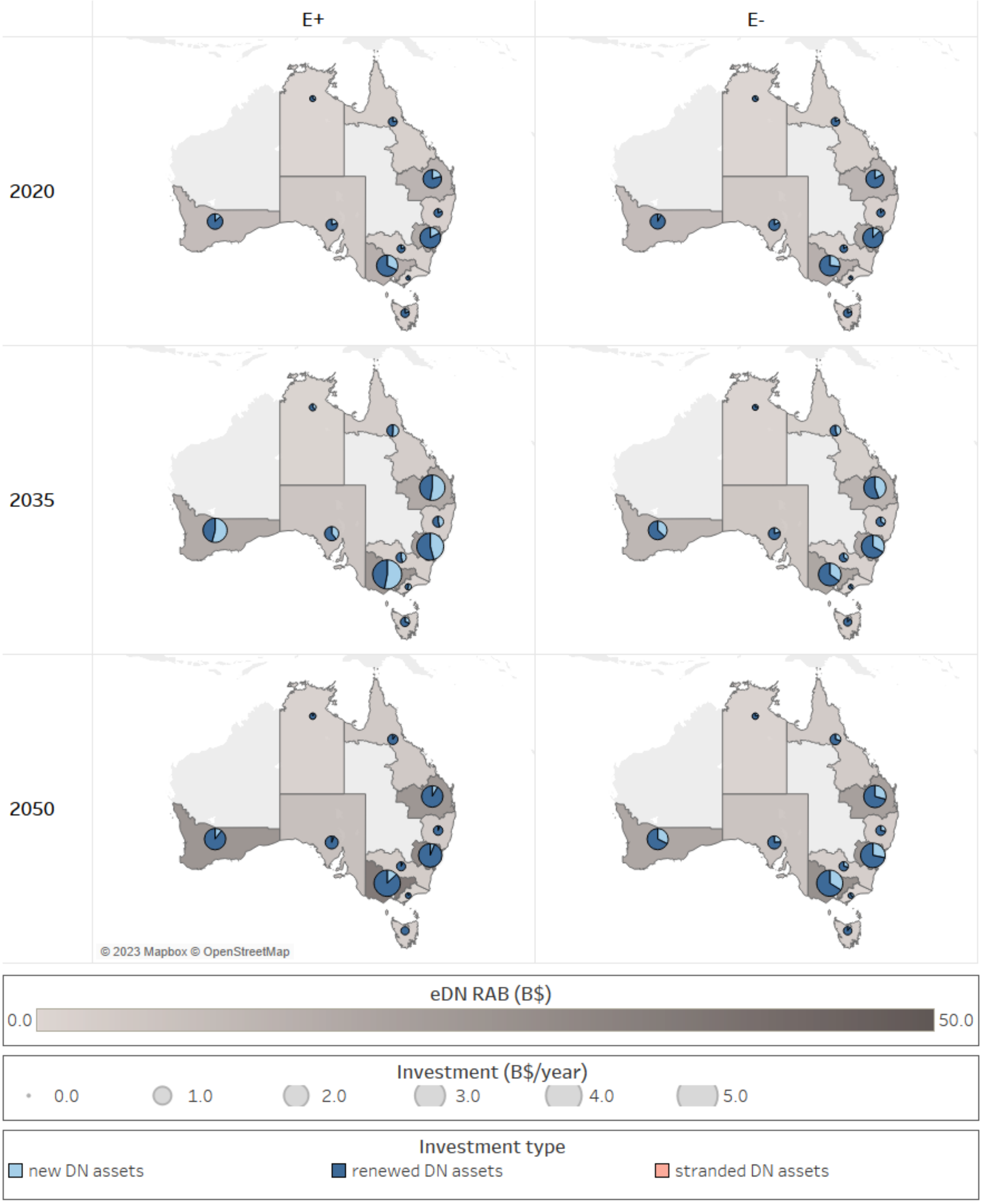


Figure 6 | Share Absolute annual investment into the electricity distribution network by type for individual NZAu regions.

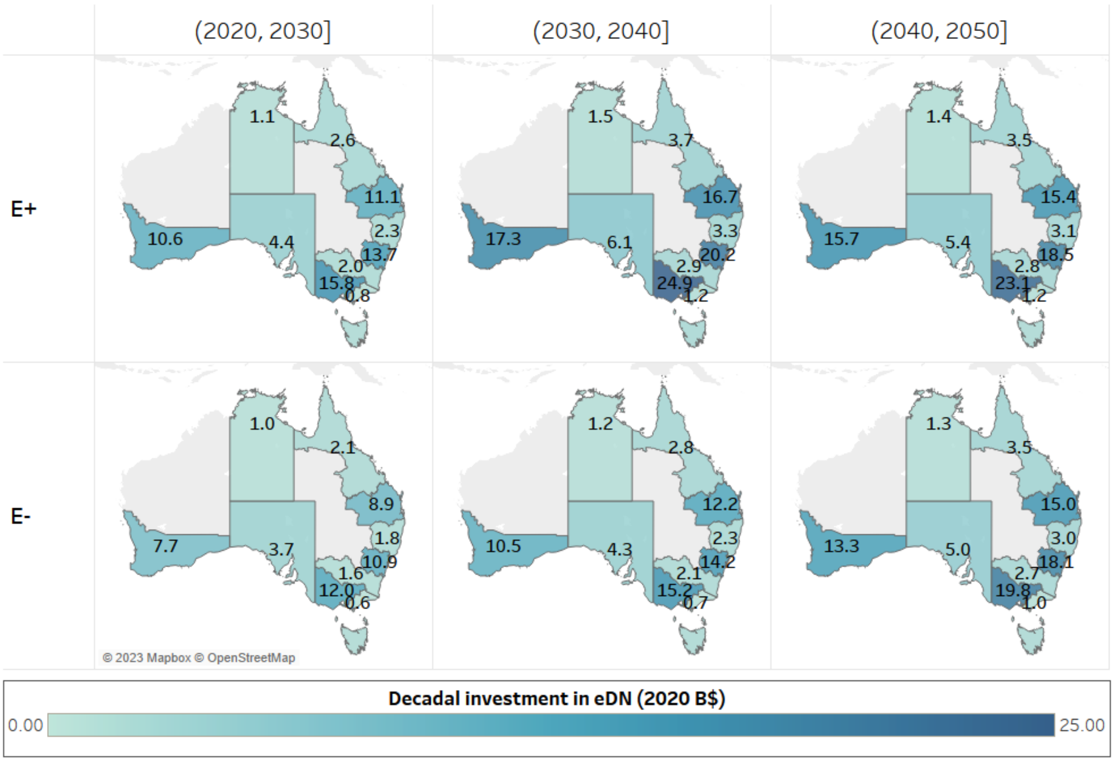


Finally, the decadal investment required (in 2020 $) is reported in Table 5 for Australia and broken down by region in Figure 7, in the three key decades for the domestic net-zero energy transition, between 2020 and 2050.

Table 5 | Australian decadal and total investment in the eDN infrastructure required (2020$ billions) by scenario.

Year	E+	E-
2020-2029	66.5	52.1
2030-2039	100.3	67.5
2040-2049	92.1	84.5
2050-2059	76.9	78.1
2020-2059	**335.8**	**230.6**

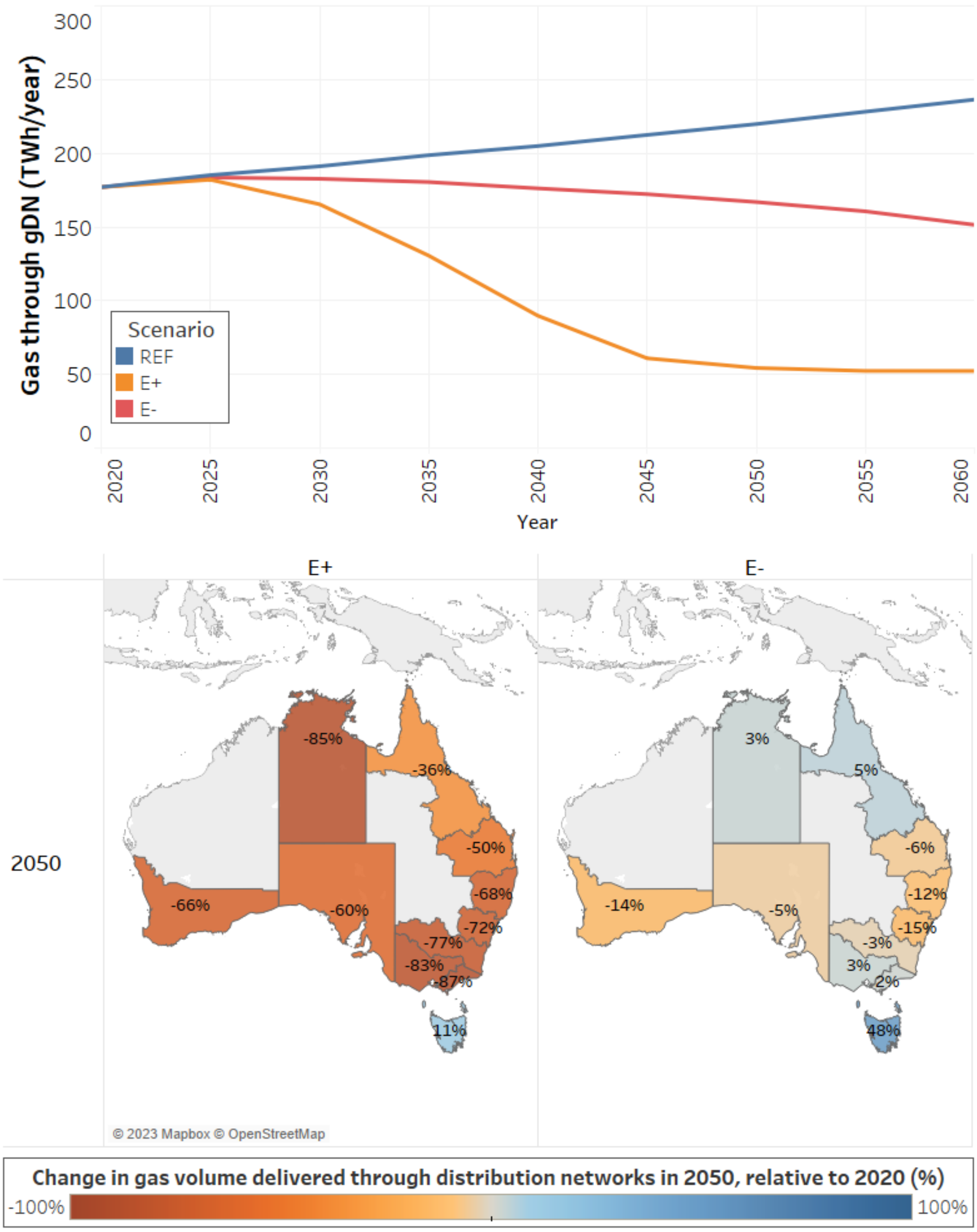
Figure 7 | Decadal investment in the eDN infrastructure required (2020 B$) by scenario and region.



5.2 Gas distribution network

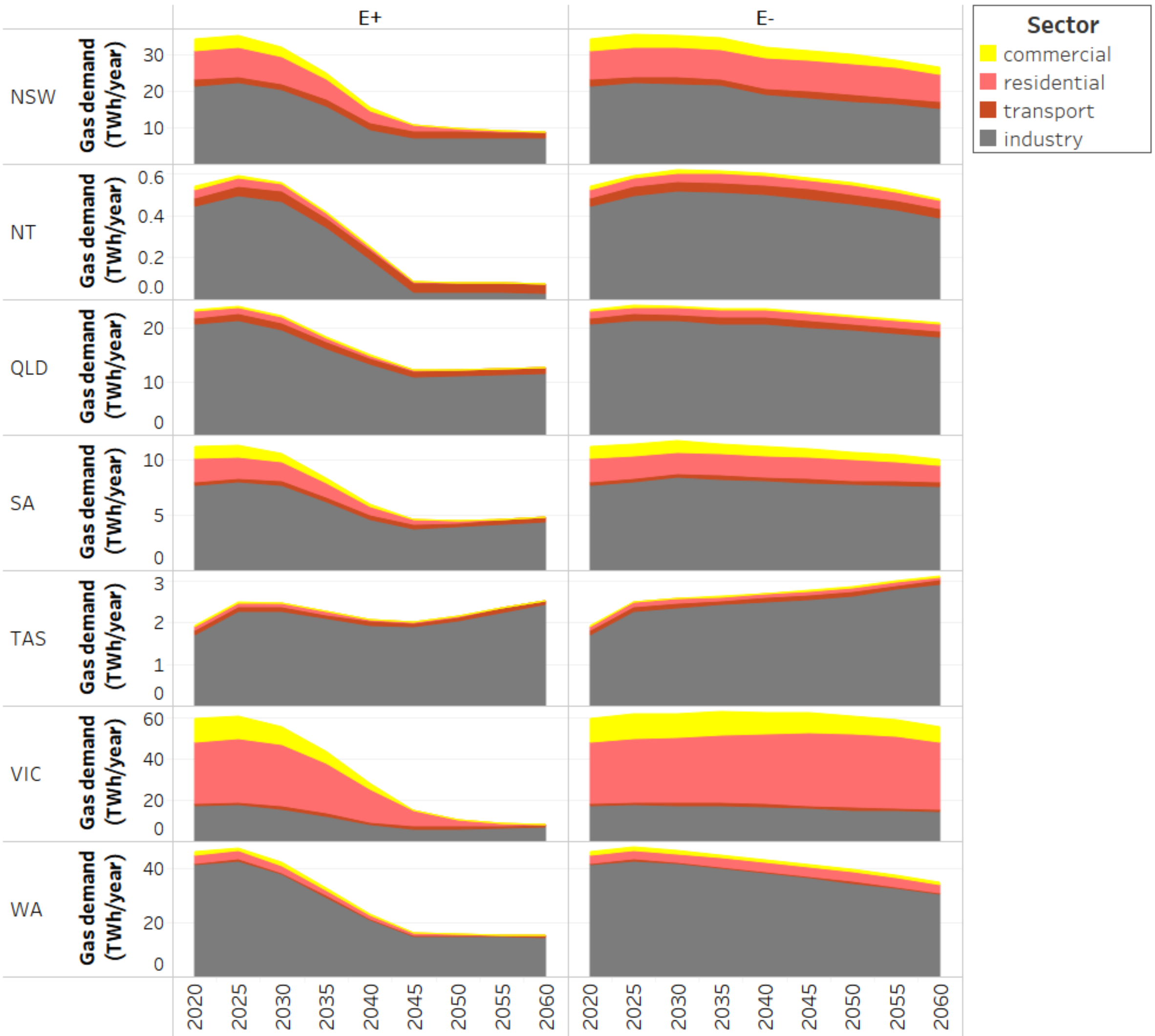
The energy volume to be served by gDN evolves over time and space as presented in Figure 8. We note that residual demand for and use of gas in 2050, once the domestic emissions constraint is zero, is required to be either entirely served by a zero-carbon fuel (synthetic methane in this approach to modelling the gDN) or is required to be entirely offset by atmospheric CO_2 withdrawals in other modelled sectors.

Figure 8 | Time and space evolution of gas demand to be served by gas distribution networks.



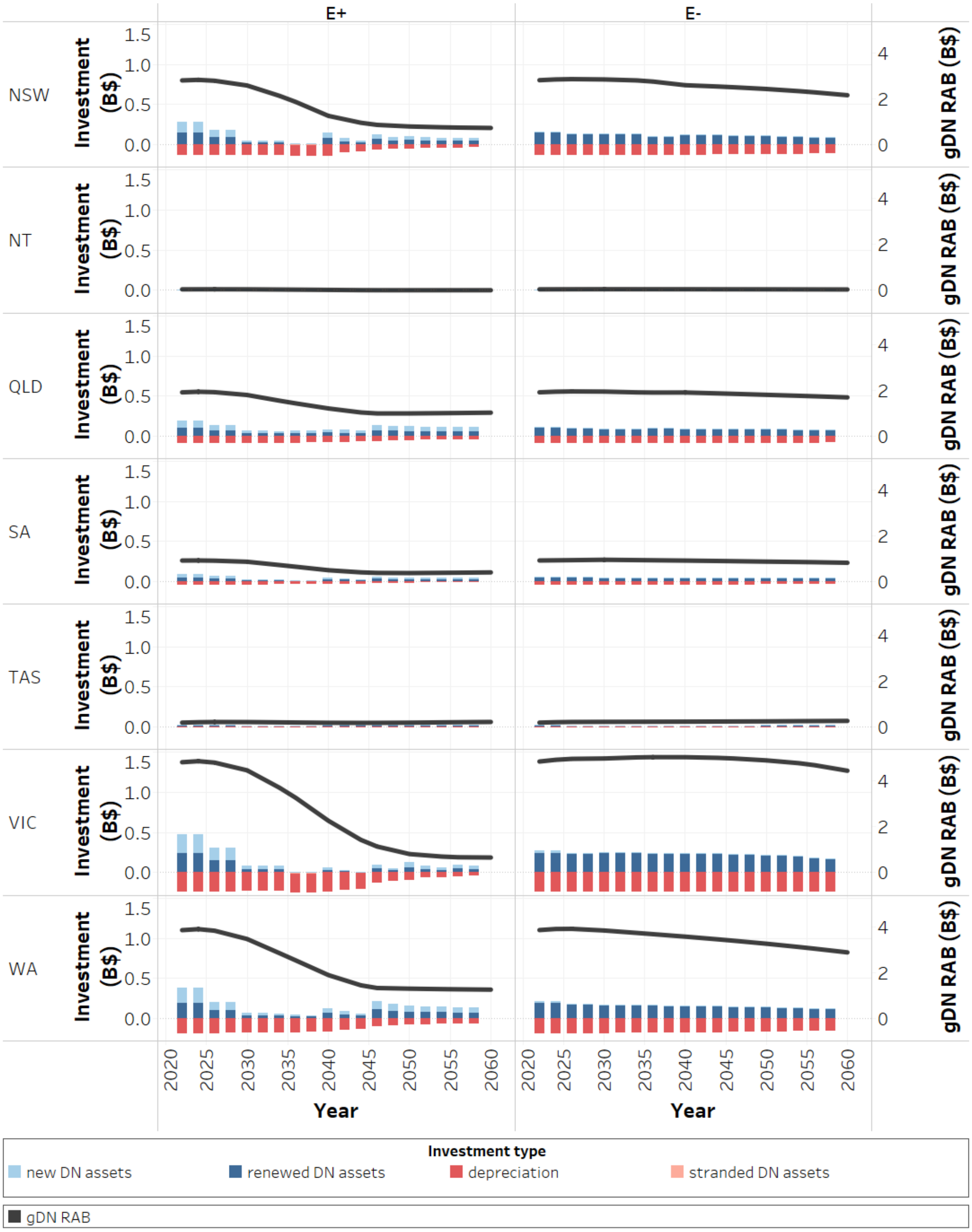
Contrary to the eDN expansion, the demand for pipeline gas exhibits a contraction over time relative to the REF Scenario as more of the final energy demand is now supplied by electricity. The case of Victoria can be used as an example of how gas and electricity networks have different prospects in the pursuit of net-zero targets, given the ~80% decrease in the volume supplied by gas (Figure 8) and the simultaneous ~140% increase in the electricity volume handled by eDN (Figure 3) in the E+ Scenario. Tasmania is the only region where the use of gas increases; gas demand in 2050 is up by 11% with respect to 2020 levels, from about 8 to 9 PJ per annum. This is attributed to the modelling of the Tasmanian cement industry upgrading and minor expansion to cover retirements elsewhere. This results in a small increase in gas demand within the cement industry in Tasmania, which is almost offset by reductions in residential and commercial gas demand. These described changes in the gas demand evolution for each state by sector are visualised in Figure 9.

Figure 9 | Time evolution of gas demand by sector, state and scenario (TWh/year). Note the different y-axis scales.



Finally focussing on the effect of such demand-side evolution on gas distribution networks, the projected annual and decadal investment requirements in the gDN by state are presented in Figure 10 and Figure 11, respectively, whereas nationwide decadal investment values are presented in Table 6. From these results, a rather limited contribution from the discussed higher gas demand in some states (Tasmania, in particular) to the overall energy gDN must supply emerges. Consistent with this observation, absolute investments into gDN are set to progressively decrease past 2020-2030 for both the E+ and E- Scenarios.

Figure 10 | Renewed, new and stranded asset annual investment and resulting evolution of the gas distribution network RAB, aggregated for each modelled state/territory, and for the E+ and E− Scenarios.



Downscaling results in Figure 10 show gDN infrastructure, on average, comes at its natural end of life and is not replaced since the $B of stranded assets is low. Taking Victoria as a more striking example given its more substantial current gas network loads which decrease sharply in the E+ Scenario, this nonetheless occurs at a pace which is consistent with the asset replacement rate. Given an average asset lifetime of 40-50 years and an average asset age of 20 years, this offers the potential to phase out most existing assets with little stranding. This suggests that owners and operators of gas distribution networks will therefore have to progressively adjust to a different business model, moving from a larger to a reduced and potentially a non-existent asset base.

The best way to coordinate this transition is likely at a localised geographical scale, providing reasonable returns to asset owners whilst ensuring reliable energy supply and protecting consumers' interests. It is nonetheless a broad and open challenge that requires significant further study. Clearly, the progressive withdrawal of network O&M as the gDN ages will compromise network reliability. However, maintaining network O&M for fewer customers increases network costs per customer, and forcing electrification may increase total energy costs per customer. At the same time, the E- Scenario shows that shutting down the gDN use is not essential for achieving net zero. Considerable further modelling and analysis is therefore required to consider how such a transition should best occur, even though significant asset stranding does not appear to be inevitable.

Figure 11 | Decadal investment in the gDN infrastructure required (2020 B$) by scenario and region.

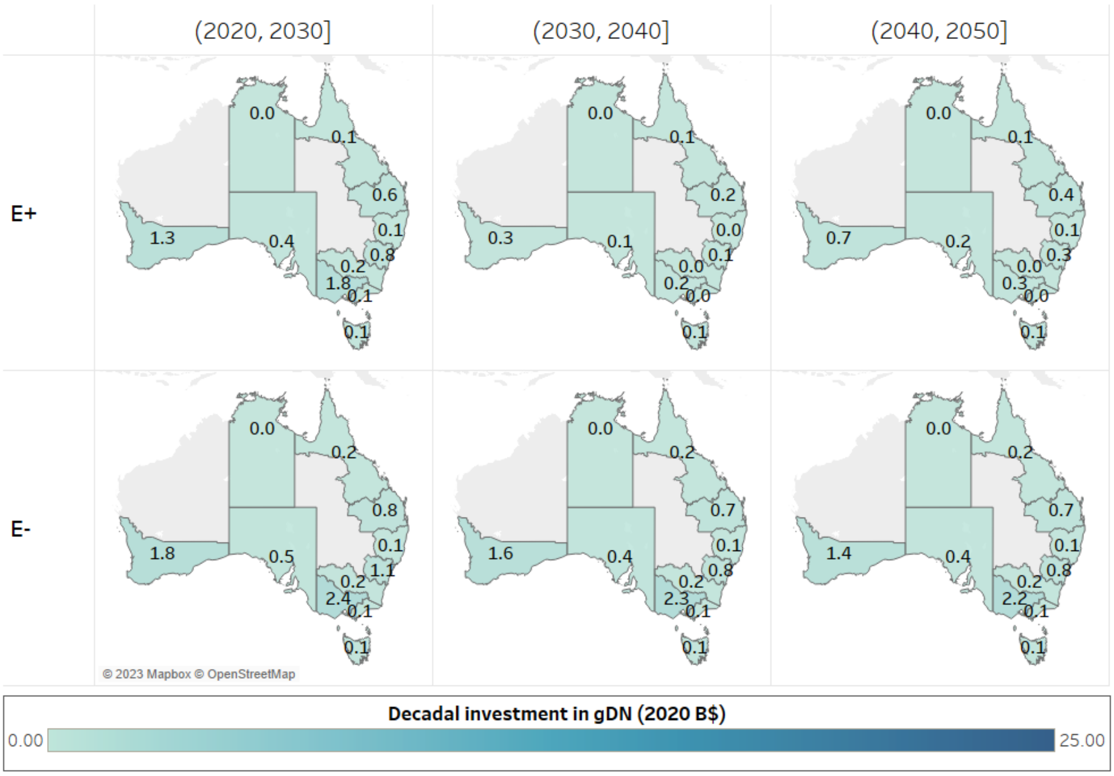
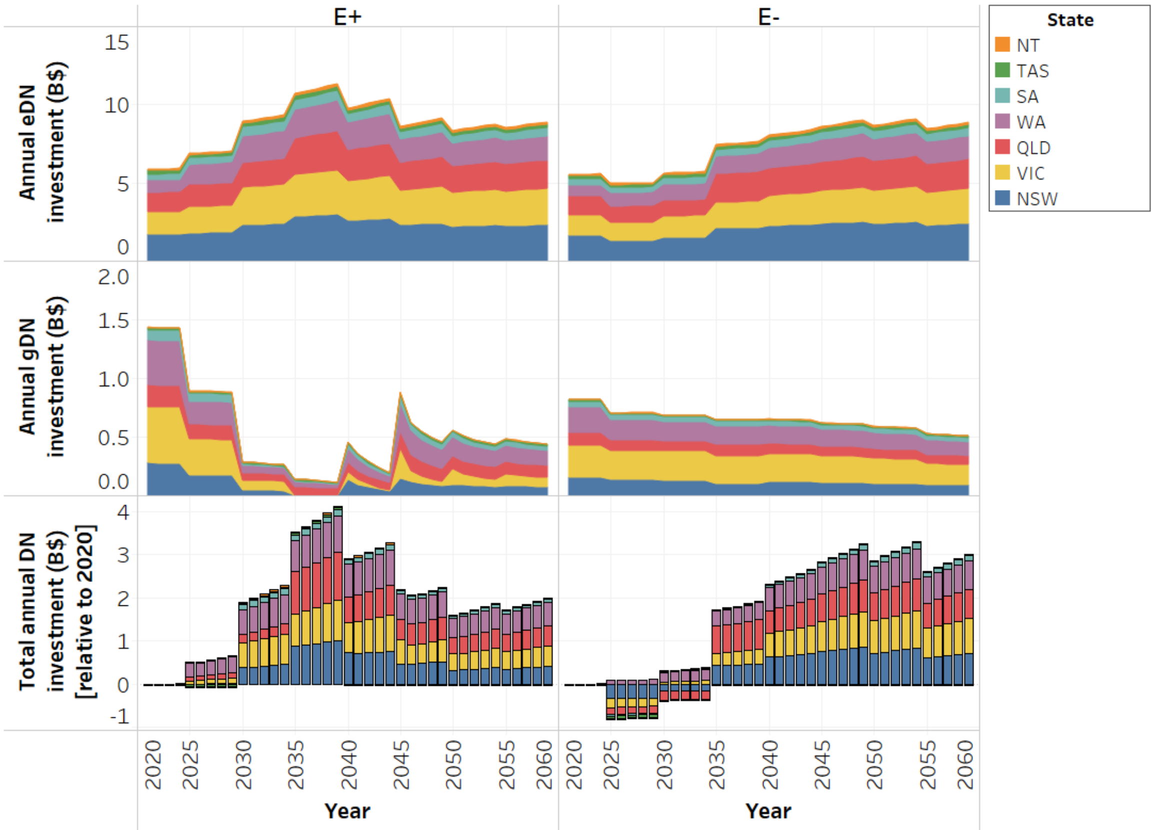


Table 6 | Australian decadal and total investment in the gDN infrastructure required (2020 B$) by scenario.

Year	E+	E-
2020-2029	5.5	7.5
2030-2039	1.1	6.6
2040-2049	2.3	6.2
2050-2059	2.1	4.9
2020-2059	**11.0**	**25.2**

Finally, it is instructive to compare the annual investment required, individually, by eDN and gDN, as well as the overall investment volume associated with the distribution network infrastructure, as presented in Figure 12. Firstly, the stark difference in the investment volume required by eDN and gDN must be noted, with eDN being around one order of magnitude larger. This is the case today, with the RAB of the eDN and gDN being roughly 80 $B and 10 $B respectively in the NEM. Situations are observed in which the majority of states experience a combined reduction of investment in eDN and gDN or the lower annual expenditure in gDN outweighs the larger one required by eDN, e.g. between 2025 and 2030 in the E+ Scenario, in New South Wales. In both these cases, the total annual investment in distribution networks is lower than the figures for 2020, at least in some states. As a consequence, a reallocation of economic resources, rather than a higher investment requirement altogether, is required in those states. Savings compared to current 2020 investment may then be used to support complementary areas of the net-zero transition, such as energy efficiency improvements. This is another key consideration that highlights how, adopting a whole energy system perspective, not only challenges, but also opportunities for the reallocation of already existing resources are opened up by and an integral part of a net-zero transition.

Figure 12 | Annual investment in eDN, gDN and overall distribution network infrastructure over time by state; E+ and E− Scenario. Note the difference in the y-axis scales.



Appendices

Appendix A

Table A.1 | Grouping of aggregated energy vectors.

Detailed energy vectors from RIO	Aggregated vector
Pipeline gas blend	natural gas
LPG blend	natural gas
Other petroleum blend	refined fossil fuels
Gasoline blend	refined fossil fuels
Diesel blend	refined fossil fuels
Fuel oil blend	refined fossil fuels
Aviation turbine fuel blend	refined fossil fuels
Hydrogen blend	hydrogen
Ammonia blend	ammonia
Biomass blend	biomass
Black coal	coal
Brown coal	coal
Electricity	electricity
Crude oil blend	oil

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