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Assessment of the Current State of Electricity and Gas Networks

ACT Government - Environment, Planning and Sustainable Development Directorate

08-Oct-2020

Commercial-in-Confidence

Electricity and Gas Networks in the ACT

Current State Assessment Report

Electricity and Gas Networks in the ACT

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Client: ACT Government - Environment, Planning and Sustainable Development Directorate

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Executive Summary

The *ACT Climate Change Strategy 2019-25* aims to achieve zero emissions from natural gas use by 2045. A key action of the *Climate Change Strategy* is a Plan to achieve zero emissions from natural gas use by 2045, developed after consideration of the potential impacts of a transition to zero emissions on the ACT's current electricity and gas distribution networks.

The ACT Government engaged AECOM to assess the ACT's current electricity and gas networks to enable future modelling of transition pathways and enable development of the Plan.

Key findings of this study

- Natural gas currently contributes about 20% of emissions in the ACT (ACT Government, 2019). No viable options have been identified to eliminate emissions from natural gas, and substitutes that could use the gas distribution network do not appear to be viable. Achievement of the zero emissions target may therefore require that the use of natural gas be terminated.

  We note that the ACT does not have enough feedstock to replace its natural gas use with biomethane, and a range of issues make it unlikely that it would be viable to use hydrogen as a substitute for natural gas, or to distribute hydrogen through the existing natural gas network.
- The ACT's current natural gas distribution network was assessed to be in good condition, and the remaining service life of the network's assets is likely to enable delivery of natural gas until possible service termination by or before 2045.
- Substitution of natural gas with electricity (based on 2018 consumption) would require that the ACT's current electricity supply capacity be increased by about 40-60%[1]. The capacity required would be greater again as the ACT's population continues to increase, and with uptake in electric vehicles. This can be offset by the uptake of renewable energy technology including distributed energy storage.
- Widespread adoption of hydrogen technology would affect the electrical network. This would rely on fuel cells in vehicles or for energy storage, but production of green hydrogen to recharge the fuel cells requires electricity (and water) and would therefore substantially increase demand for electrical energy.
- The ACT's current electricity distribution network is designed around a set of substations and feeders that serve energy to ACT suburbs via overhead lines or underground cables.

  Evoenergy's supply performance has been among the best in the Australian industry, and there is no reason to conclude that with its regulatory environment (and continued effective oversight by the regulator) and compliance with its own policies and procedures, Evoenergy's performance will not be maintained at historical levels.

  Evoenergy has maintained its assets in a good condition and they are generally about halfway through their expected service lives. It therefore seems likely that Evoenergy will continue to keep its assets in a satisfactory condition so that it can continue to meet its mandated performance targets, and that the regulator will approve the funding of this investment.

  The main constraint in the network is supply capacity via the current substations. Evoenergy is able to meet current expectations of peak demand with prudent contingency arrangements, but its network does not have capacity to deliver the 40-60%[1] increase in demand needed to substitute natural gas with electricity. A substantial investment is therefore likely to be required to increase supply capacity, which could be reduced but not avoided through implementation of peak demand management strategies.

[1] Estimated by AECOM considering the July 2018 demand peak, taking into account the relatively greater efficiency of electrical appliances compared to gas appliances, refer to Section 4.0 for further discussion on projected energy demand and supply capacity.

Transition pathways policy implications

- An impairment charge is likely if natural gas network is terminated in or before 2045. Termination (make good) of a natural gas distribution network involves cleaning the pipes, sealing them and abandoning them either empty or filled depending on their location.
- A long-term decline in the use of natural gas as a result of the ACT Government's policies would avoid any need for network enhancement and minimise the investment required for asset sustainment during the period.
- Energy is lost when producing hydrogen (production of green hydrogen is not 100% efficient), so it is unlikely that hydrogen or fuel cells would be viable ahead of electrical energy as a substitute for natural gas, but this option is expected to be viable as a substitute for current transport fuels.

  It appears unlikely that hydrogen would be piped to refuelling stations for safety and leakage reasons, so this option does not appear to be a viable reason to retain the natural gas distribution network. The trend appears to be to transport fuel cells rather than the hydrogen itself.

  Hydrogen-based fuel cells can also be used for distributed energy storage.
- It is possible to reduce peak demand and therefore reduce the impact on the electricity network:
  - A continued rollout of rooftop solar energy (without energy storage) would reduce overall demand but not reduce peak demand (which typically occurs in the early evening). The rollout is likely to increase power quality issues caused by the bi-directional flow of power and therefore force network upgrades and would increase the unit cost of grid electricity (fixed costs would have to be recovered from a smaller quantity of energy served).

    Rooftop generation currently has a penetration of about 16% in the ACT (SolarQuotes, 2020), but even at 100% penetration this resource would not be sufficient to fully substitute for the natural gas .

    It may be potentially be economic to encourage a high degree of energy self-sufficiency in households based on rooftop solar generation and battery storage, and particularly if the capacity to charge electric vehicles were included.
  - The use of distributed (including community) energy storage associated with rooftop solar energy generation has been shown to reduce peak demand. This strategy would reduce the investment needed in the grid when natural gas is terminated but not eliminate it.
  - The universal rollout of electric vehicles would increase overall demand for electricity but not necessarily increase peak demand. Adoption of vehicle-to-home charging (using the vehicle battery to serve energy to the home during peak demand periods and recharging off-grid during off-peak periods) could potentially provide a sufficiently large resource to be a viable substitute for natural gas (together with rooftop solar generation and distributed energy storage).

    With current technology, vehicle-to-home charging would shorten the life of the vehicle's battery, so this option may not be attractive to vehicle owners (batteries are typically about 45% of the vehicle cost (Bloomberg New Energy Finance, 2017)). Battery technology is being improved, so the availability of affordable batteries with longer cycle lives would alleviate this concern.

    Commercial vehicles and long-distance travellers are likely to need fast charging facilities. These are likely to be located more or less where petrol stations are currently located, but those sites would need their electrical supply enhanced.

    It has been estimated by Bloomberg New Energy Finance that electric vehicles will become cost neutral with internal combustion engines around 2024 (Bloomberg New Energy Finance (BNEF), 2019), so they are likely to become attractive trade-in options for the current private vehicle fleet after that.
- This report has identified several opportunities for future work to inform policy development at Section 8.0.

1.0 Introduction

The ACT currently uses energy delivered via natural gas and electricity distribution networks:

- The natural gas distribution system network is owned by Evoenergy Gas and operated by Jemena. It consists of approximately 4,000km of pipeline and delivered approximately 8.2 PJ (2,274 GWh) in 2018 (43% of the total energy supplied).
- The electrical distribution network is owned and operated by Evoenergy. It consists of more than 2,300 km of overhead lines and 2,600 km of underground cables and supplied 2,986 GWh in 2018 (57% of the total energy supplied).

As of 2019-20, the ACT's electricity supply is 100% renewable, and the largest remaining sources of emissions are transport (estimated at over 60%) and natural gas (over 20%) (ACT Government, 2019). The *ACT Climate Change Strategy 2019-25* identifies an action for the ACT Government to map out a pathway to transition towards zero emissions, focussed on the transport and gas sectors.

A key action of the *Climate Change Strategy* is the development of a Plan for achieving zero emissions from natural gas use by 2045. The Plan will be released by 2024, and will enable the ACT Government to develop a considered policy position which accounts for potential developments in zero emissions technologies and appliances, and in alternatives to natural gas. It will also need to consider the potential impacts of a transition to zero emissions on the ACT’s electricity and gas networks.

The ACT Government required an assessment of the ACT’s current electricity and gas networks for use as the basis of future modelling of transition pathways for the ACT, and the study required was awarded to AECOM.

The study is expected to provide an assessment of the impacts of strategies to reduce renewable energy on the ACT’s electricity and gas network infrastructure, reporting on:

- The current status (age and asset life) of the infrastructure;
- Current supply performance;
- Projected energy demand and supply capacity;
- Strategies to reduce energy emissions in relation to both networks.

This report presents the findings of the study in several sections, including reviews of:

- The current state of the ACT’s electricity distribution network;
- The current state of the ACT’s gas distribution network;
- Current and projected energy demand and supply;
- The impact on the distribution systems of strategies to further reduce emissions, including consideration of the potential impact of increasing use of electric vehicles;
- Substitutes for natural gas, and their potential impact on the distribution systems.

2.0 The Current State of the Electricity Distribution Network

A map of the network has been included for context (Figure 1 *Source:* (Evoenergy)).

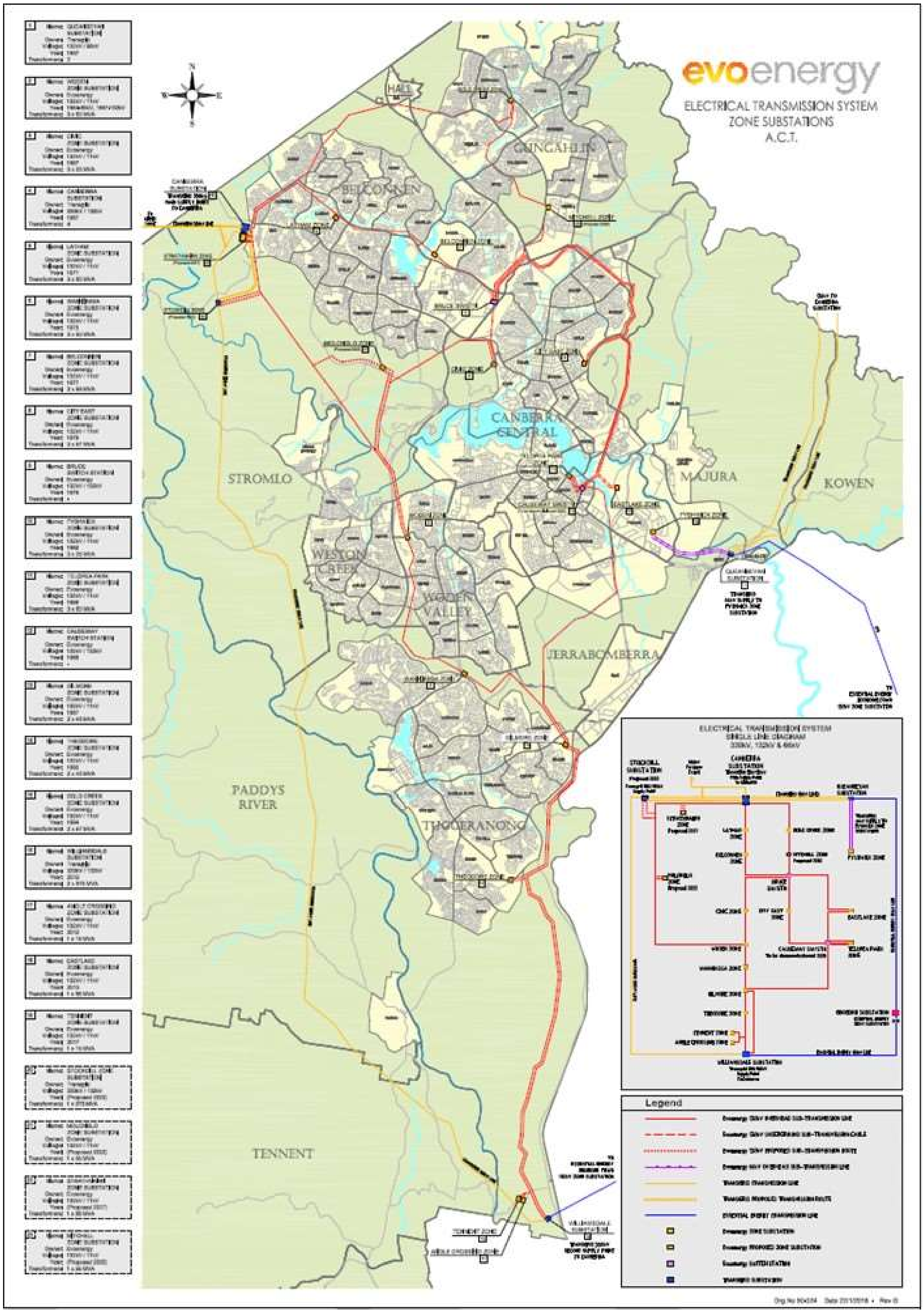

Figure 1 The ACT electricity distribution system by zone

This section summarises the current state of the ACT's electrical network and provides an estimate of the remaining life expectancy of current assets. It starts with an overview of the network taken from Evoenergy's recent submission to the Australian Energy Regulator (AER) and then summarises the state of distribution assets and supply capacity by district as defined by Evoenergy using available data. Evoenergy's grouping of suburbs to supply zones and districts is attached as Appendix A.

It should be noted that:

- Evoenergy, like all public distribution utilities, is subject to regular review by its regulator, and is required to demonstrate during each review that it operates in a prudent and efficient manner. Maximum prices for electricity are set by the regulator after each review and are influenced by what the regulator considers efficient costs.
- Evoenergy is monitored continually on its service performance, specifically including standard performance measures of supply reliability, and must comply with mandated performance criteria. A later section of this report demonstrates that Evoenergy performs well against these indicators.
- Evoenergy has a set of asset class plans and asset management strategies that rely on historical performance by asset class to predict the future risk of failure in the class. It uses that data to plan asset refurbishment and renewal in order to achieve its mandated performance targets as efficiently as possible.

2.1 Electricity distribution capacity

Electricity is distributed from a set of substations, each of which serves specific suburbs (more than one substation can serve the same group of suburbs to provide redundancy and reliability). The substations are located by Evoenergy in 'zones', and the Evoenergy uses the term 'district' to identify zones which are served by more than one substation. The grouping of suburbs to Evoenergy's zones and districts, along with the population served in each case, is shown in Appendix A.

Since 'capacity' is measured at the substation (zone) and there is more than one substation serving a zone, it is simplest to make an assessment of supply capacity using the 'district' grouping. Supply is more complex than this suggests, because many of the zones can transfer load - the extent to which load transfer can happen is shown in Table 1, which indicates the power (MVA) able to be transferred from the district shown in the left column to the district shown in the top row of the table.

Table 1 Load transfer capability (simplified)

			TO							
FROM	Current Summer Emergency 2-hr Rating (MVA)	Current Winter Emergency 2-hr Rating (MVA)	Belconnen	North Canberra & City	Canberra East	South Canberra	Tuggeranong	Gungahlin	Tennent	Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi
Belconnen	158.0	190.0		16.9						
North Canberra & City	209.0	255.0	6.1		0.1	13.6				1.9
Canberra East	63.0	76.0		0.6		5.8				
South Canberra	142.0	142.0		17.3	10.8		15.8			16.0
Tuggeranong	219.0	252.0				0.9				16.6
Gungahlin	76.0	76.0	4.1	2.6						
Tennent	15.0	15.0								
Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi	95.0	114.0		3.3		4.3	19.0			

Presenting this load sharing accurately would make a district-based capacity assessment unnecessarily complex, so for the purposes of this study supply and demand are compared at district level (ignoring load transfers between districts). The transfer capacity shown is based on zone substation transformer emergency rating (which in practice can only be used intermittently to avoid a significant reduction in transformer life). Transfer capacity is also substantially limited by 11 kV feeder capacity (for which data availability is limited).

An analysis of supply capacity is made in Table 2 and Table 3 (for summer and winter loads respectively). The tables include:

- The supply capacity by district, using the substation emergency two-hour rating measured in MVA (noting that the emergency capability can only be used intermittently).
- The capacity enhancement projects currently planned by Evoenergy to ensure that it is able to satisfy future load projections. These projects are listed in Appendix B, and the additional substation capacity has been included in the tables.
- The current and projected population served in each of the districts (using the data attached in Appendix A).
- The 50% Probability of Exceedance (PoE) maximum demand by district by season for 2020, as published by Evoenergy (Evoenergy, 2019).
- Projections of peak demand by district by season extrapolated from expected population growth (presented by suburb in Appendix A) and assuming that the current load per household remains constant over the period. It should be noted that recent trends have shown a slow decline in energy use per household, but for the purpose of this study the more conservative assumption has been made. No allowance has been made here for substitution of electricity for gas.
- The ratio of demand to capacity for 2018/19, 2031 and 2041, using colour coding to highlight periods and districts where the projections indicate that capacity may be constrained (a red highlight indicates that demand exceeds supply capacity, and orange indicates that demand is projected to exceed 80% of installed capacity.

Table 2 Electricity demand and capacity projection by district, summer

District	Emergency 2-hr Rating (MVA)	Project	Future Capacity (MVA)	Population			Demand (MVA)			Demand / Emergency 2-hr Rating		
				2021	2031	2041	2020	2031	2041	2020	2031	2041
Belconnen	171	New Strathnairn ZSS.	226	104,255	125,005	140,297	109	143	169	64%	63%	75%
North Canberra & City	209	New Mitchell ZSS	264	59,437	79,500	90,088	134	177	169	64%	67%	64%
Canberra East	54		54	1,495	1,361	1,326	17	23	21	31%	43%	39%
South Canberra	142	Flyshwick decomissioning	114	31,234	32,209	36,196	116	106	103	82%	93%	90%
Tuggeranong	219		219	87,941	86,547	88,922	133	135	151	61%	62%	69%
Gungahlin	76	New third transformer at Gold Creek	131	82,118	86,644	86,905	68	72	73	89%	55%	55%
Tennent	15		15				1	3	3	7%	20%	20%
Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi	95	New Molonglo ZSS	150	77,536	111,211	138,739	77	111	124	81%	74%	83%
Total ACT	**981**		**1,173**	**444,016**	**522,477**	**582,473**	**655**	**770**	**814**	**67%**	**66%**	**69%**

Assuming no load sharing

Table 3 Electricity demand and capacity projection by district, winter

District	Emergency 2-hr Rating (MVA)	Project	Future Capacity (MVA)	Population			Demand (MVA)			Demand / Emergency 2-hr Rating		
				2021	2031	2041	2020	2031	2041	2020	2031	2041
Belconnen	190	New Strathnairn ZSS.	245	104,255	125,005	140,297	121	160	192	64%	65%	78%
North Canberra & City	257	New Mitchell ZSS	312	59,437	79,500	90,088	124	185	181	48%	59%	58%
Canberra East	54		54	1,495	1,361	1,326	18	23	21	33%	43%	39%
South Canberra	142	Flyshwick decomissioning	114	31,234	32,209	36,196	101	109	108	71%	96%	95%
Tuggeranong	252		252	87,941	86,547	88,922	149	137	153	59%	54%	61%
Gungahlin	84	New third transformer at Gold Creek	139	82,118	86,644	86,905	73	71	71	87%	51%	51%
Tennent	15		15				1	3	3	7%	20%	20%
Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi	114	New Molonglo ZSS	169	77,536	111,211	138,739	80	134	156	70%	79%	93%
Total ACT	**1,108**		**1,300**	**444,016**	**522,477**	**582,473**	**667**	**821**	**886**	**60%**	**63%**	**68%**

Assuming no load sharing

There are variations by district (Gungahlin is currently being upgraded, but South Canberra appears to need more capacity in the future).

Total demand is anticipated to be at around 68% capacity by 2041. This reflects the firm capacity concept applied for planning, which allows for credible contingency events such as the unavailability of one transformer. For a substation with three transformers, this represents a maximum load at around 66% of installed capacity.

The capacity analysis is presented visually, where the substations are located on the map of the ACT using dots, and the colour of the dot reflects current capacity utilization (Figure 2) and expected capacity utilisation in 2031 (Figure 3).

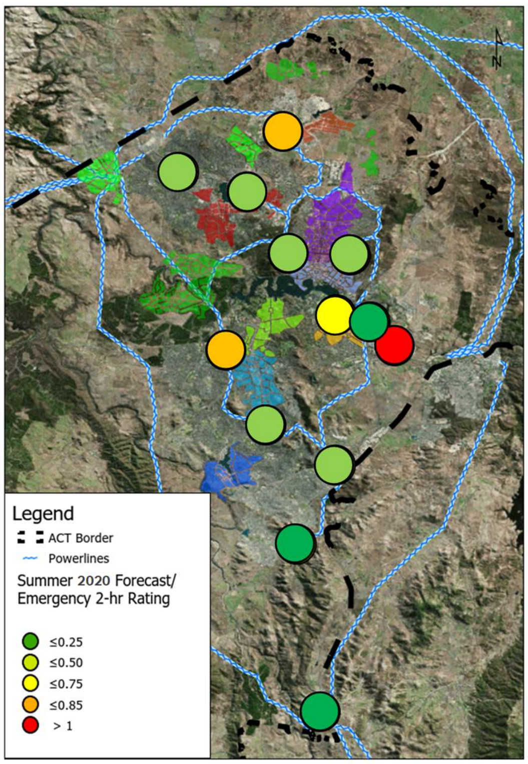

Figure 2 Capacity by zone substation, summer 2020

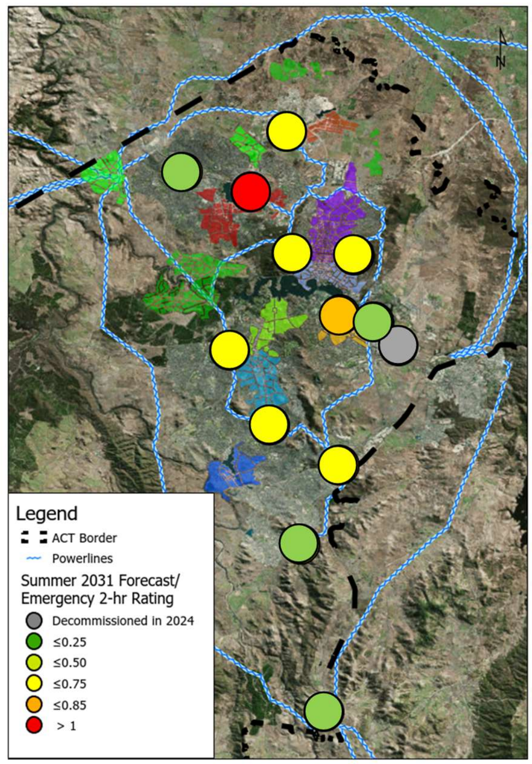

Figure 3 Capacity by zone substation, summer 2031

In addition to the capacity of zone substations addressed in this section, the ability to meet demand may be constrained by other network elements (notably; feeders and switchboards). A number of capacity issues already exist with network feeders, as detailed in Appendix B.

2.2 The state of the electricity distribution network

The ACT's electrical distribution network by asset class, adapted from Evoenergy's 2019 submission to the Australian Energy Regulator (AER), is shown in summary form in Table 4 (EvoEnergy, 2019). [2] [3] [4]

[2] For wooden poles which have been staked (reinforced to extend service life), the reported life expired and life remaining is based on the date of pole staking.
[3] The reported life expired and life remaining for zone substations is based on the commissioning date of the substation (as reported in Evoenergy's Annual Planning Report) and does not account for any refurbishment works since undertaken.
[4] Asset life expectancies are as contained in Evoenergy's submissions to the AER, where available.

Table 4 Network Summary

Asset Group	Asset Category	Quantity	Unit	Mean Useful Life (years)	Mean Life Expired (years)	Mean Life Remaining (years)
Poles	Wood	28,105	Number	42	32	10
Poles	Concrete	12,054	Number	100	20	80
Poles	Steel	6,116	Number	65	21	44
Poles	Other	4,231	Number	80	12	68
Cable	Overhead	2,574	Length (km)	50	46	4
Cable	Underground	3,076	Length (km)	60	33	27
Cable	Service Line	213,337	Number	50	34	16
Substation	Zone Substations	13	Number	45	34	11
Substation	Distribution Substations	4,719	Number	50	27	23
Network Assets	Network Assets	3,904	Number	12	17	-5

Table 4 indicates that the assets are generally in a satisfactory condition (based on the proportion of expected service life remaining).

It is easier to visualise their condition using a lifecycle display format as presented in Figure 4, which shows current mean asset condition and remaining service life expectancy by asset class against a standardised asset deterioration curve.

For simplicity, a normal failure distribution has been used for the presentation, but it should be noted that each asset has its own specific failure distribution derived from Evoenergy's asset history, and these are used by Evoenergy to predict condemnation rates for all its important assets.

In Figure 4 the dotted line illustrates a standardised asset deterioration curve based on a normal distribution of failure. The vertical axis shows asset condition on a 5 point scale, where a rating of 4 is used to indicate the point in the asset's service life where it would be condemned or de-rated because the risk of being unable to meet minimum service performance targets becomes unacceptable. For assets where condition is the primary cause of failure, a prudent and efficient operator would generally keep their assets at an average rating of about 3, representing a suitable trade-off of cost and risk to service levels. [5]The size of the bubble reflects the regulatory asset base (RAB) value.

[5] Condition is however not the primary cause of failure for all assets. For instance, failure of overhead cable can be caused more often by weather events than deterioration of the cable itself. For other (non-critical) assets, failure will not result in an unacceptable outage (by definition) and it can be more cost-effective to run these to failure. An assessment of asset criticality has not been undertaken for the purpose of this study.

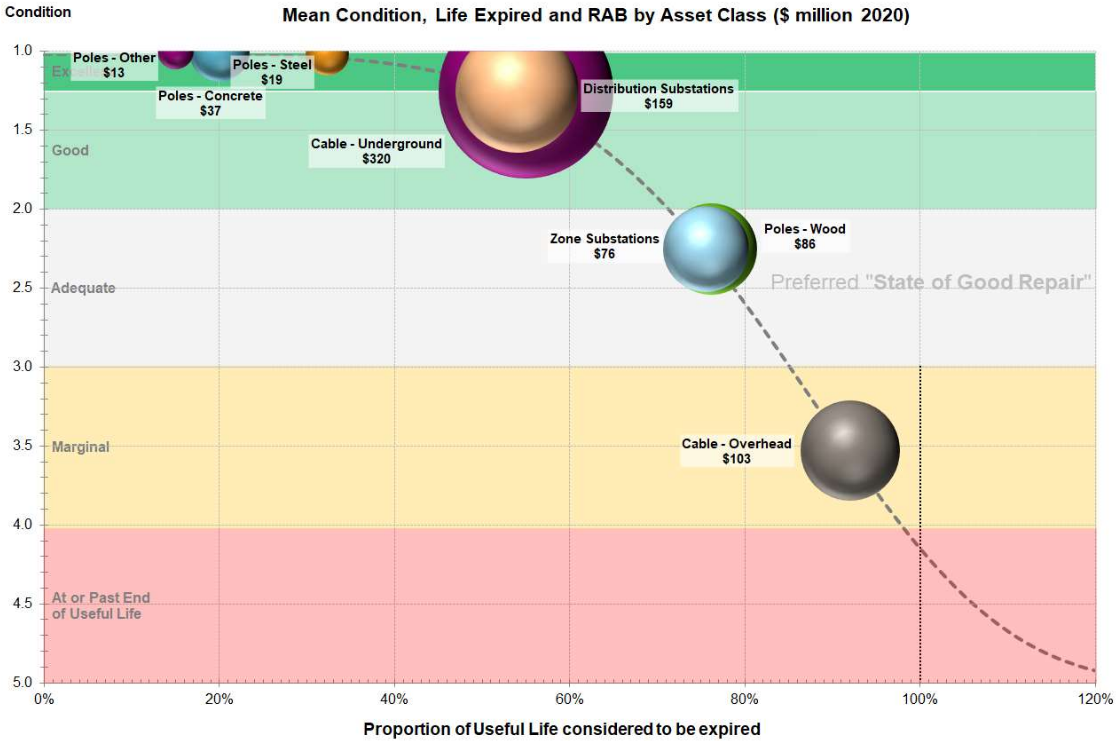

Figure 4 Mean Condition and Life Expired by Asset Class

Figure 4 and Table 4 (based on Evoenergy's submission to the AER (EvoEnergy, 2019)) indicate that:

- Evoenergy's overhead Cables are (on average) in a marginal condition with about 10% of expected service life remaining. These overhead conductors are predominately aluminium, with short slack spans in a non-corrosive environment and are not overloaded, so they would be expected to experience minimal deterioration. The mean useful life (and remaining life) as reported by Evoenergy's may reflect accounting assumptions rather than the expected service life and these assets may have a longer service life than indicated.
- Almost all other asset classes are in good to adequate condition, with expected remaining life ranging from 25% for hardwood poles and zone substations, 45% for underground cables, 50% for distribution substation assets and more for other pole types.
- Underground cables are the largest asset class by RAB value.

The brief for this study includes an assessment of capacity and asset condition by geographic area. The data provided by Evoenergy to the AER in its pricing submission is aggregated by asset class and does not include data by location, so we have relied on detailed pole and cable data from 2015 to derive a summary of life expired and remaining life by area (using Evoenergy's districts) as an indication of the state of the network in each district. It is noted that actual condition may vary from the expected condition presented in this section, due to usage, the level of historic maintenance undertaken, and other environmental or operational factors.

2.3 Poles

[redacted]

[redacted]

[6] This analysis is based on data dated 2014. Condition was projected forward to the current date, and a rate of pole renewal consistent with historic levels assumed to have occurred over the period.

[redacted]

[redacted]

2.4 Overhead Conductors

The age profile of overhead conductors is presented in Figure 9 (EvoEnergy, 2019).

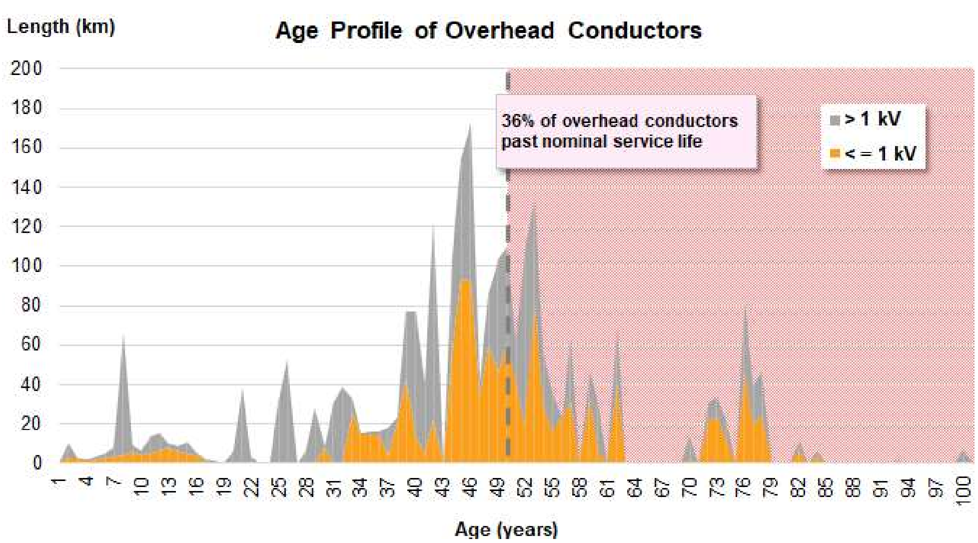

Figure 9 Asset age profile – overhead conductors

Approximately 36% of overhead conductors by length are currently past the nominal service life of the cable (which is generally assumed by Evoenergy to be 50 years).

As noted in Section 2.2, the overhead conductors have a longer service life expectancy than underground cable and appear to have experienced less deterioration to date than implied by their age, indicating that the assets may be in better condition than expected. If this is the case, current projections of renewal timetables and funding for the overhead conductors may be able to be deferred.

2.5 Underground Cable

The age profile of underground cable in the ACT is presented in Figure 10 (EvoEnergy, 2019).

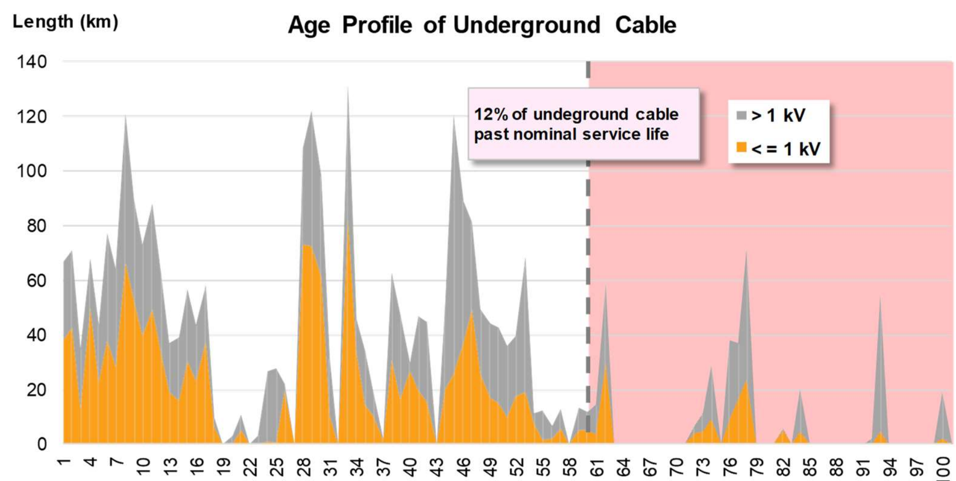

Figure 10 Asset age profile – underground cable

Different types of cable have different life expectancies, ranging from 70 years for paper insulated cables to 45 years for polymeric insulated cable assets (Evoenergy, 2018). Approximately 12% of underground cables by length are currently past the nominal service life of the cable.

It is generally expected that as sections of the network are replaced over time, there will be a trend toward a steady state of asset renewal. The age profile of the cable population is not evenly distributed, however, and a relatively large percentage is expected to reach nominal end of life from around 2025. This should cause a short-term step-up in the rate of cable renewals.

Evoenergy's FY18 forecast for capital expenditure on high-voltage underground cable, shown in Figure 11, demonstrates this expectation by showing an increases in capital required for the FY24-29 period (Evoenergy, 2018).

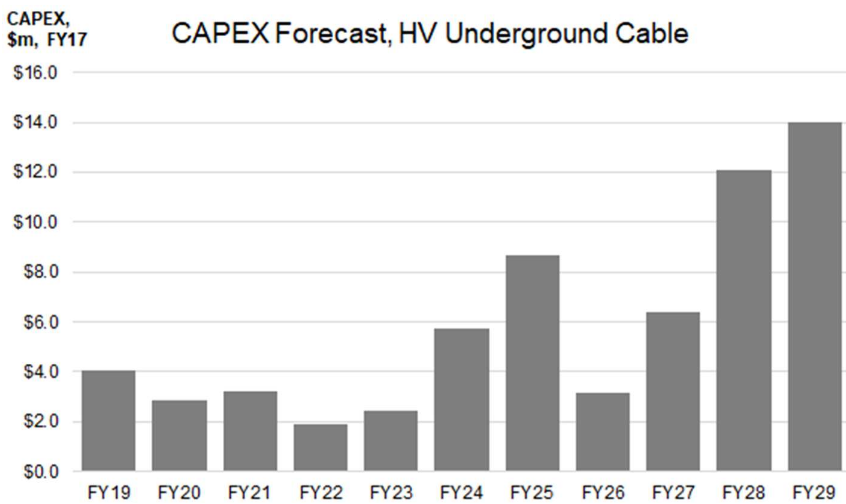

Figure 11 Evoenergy capital expenditure forecast, HV underground cable

2.6 Transformers

The age profile of transformers rated for less than 22kV (distribution substation and pole mounted transformers) is presented in Figure 12 (EvoEnergy, 2019).

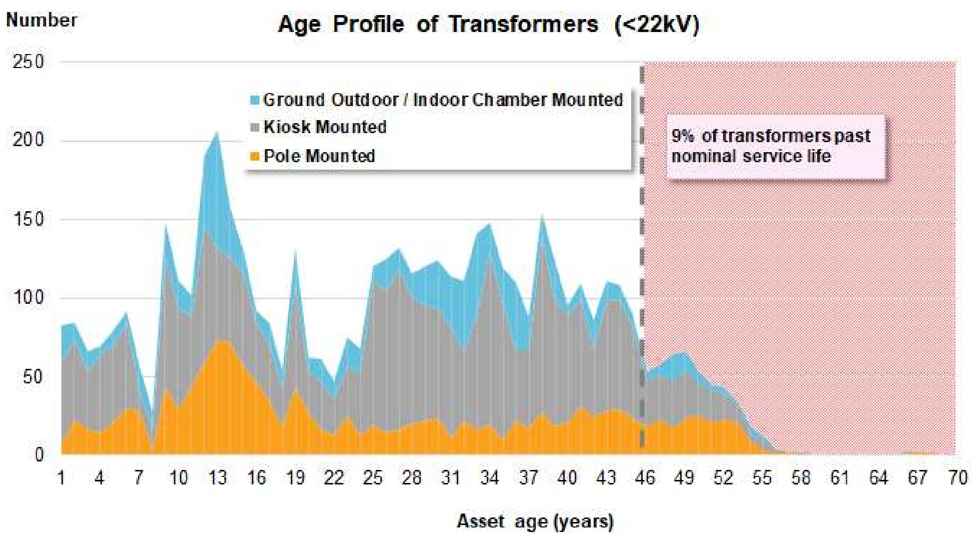

Figure 12 Asset age profile – transformers (<22kV)

Approximately 9% of the distribution substation and pole mounted transformers appear to be past their nominal service life (which is generally assumed by Evoenergy to be 45 years) but are clearly still reliable (suggesting that that their service life is likely to be longer than originally expected).

The age profile of zone substation transformers is presented in Figure 13 (EvoEnergy, 2019).

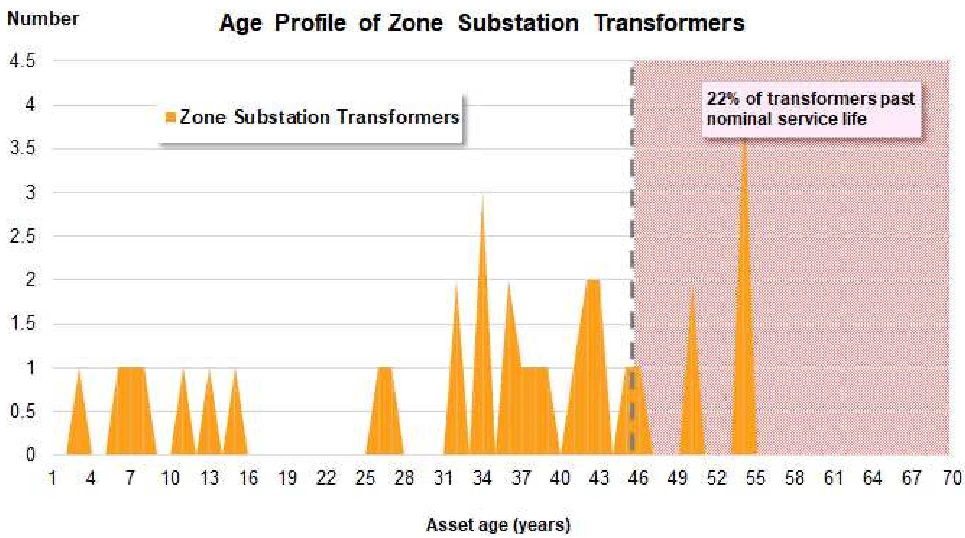

Figure 13 Asset age profile – zone substation transformers

Approximately 22% of the zone substation transformers appear to be currently past their nominal service life (which is generally assumed by Evoenergy to be 45 years), but investment in zone substations is likely to be driven by capacity constraints, not asset condition (Section 2.1).

2.7 Performance of the electricity distribution network

The quality and performance of the electricity distribution service in the ACT is mandated, and Evoenergy reports its performance annually. Two commonly used indicators of performance are supply interruption duration (SAIDI) and supply interruption frequency (SAIFI), both of which have mandated maximum performance levels.

Figure 14 and Figure 15 show unplanned SAIDI and SAIFI compared to the AER's Service Target Performance Incentive Scheme (STPIS) (Evoenergy, 2019).

Figure 14 Duration of unplanned interruptions in minutes per customer per year (SAIDI)

Figure 15 Frequency of unplanned interruptions per customer per year (SAIFI)

While Evoenergy appears to have breached the STPIS in the past, it is actually one of the best performing distributors nationally when the performance data is normalised to customer numbers (Figure 16 and Figure 17) (AER, 2019).

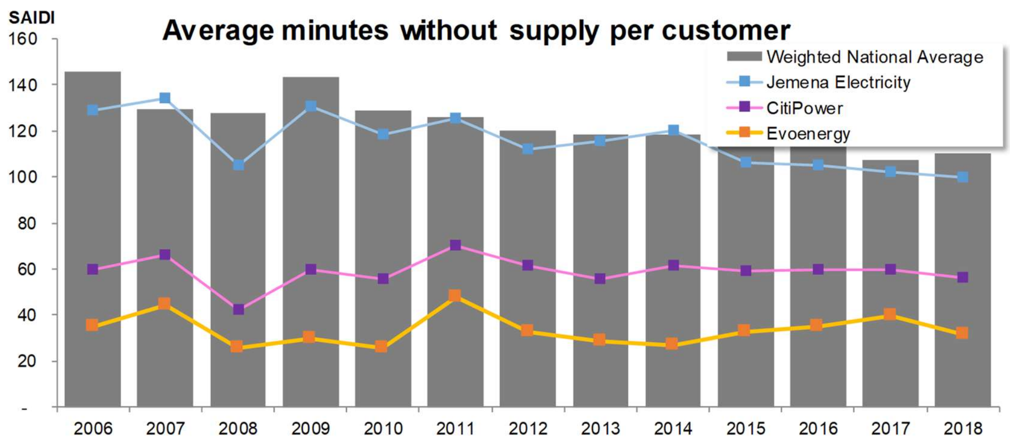

Figure 16 SAIDI performance compared to national average

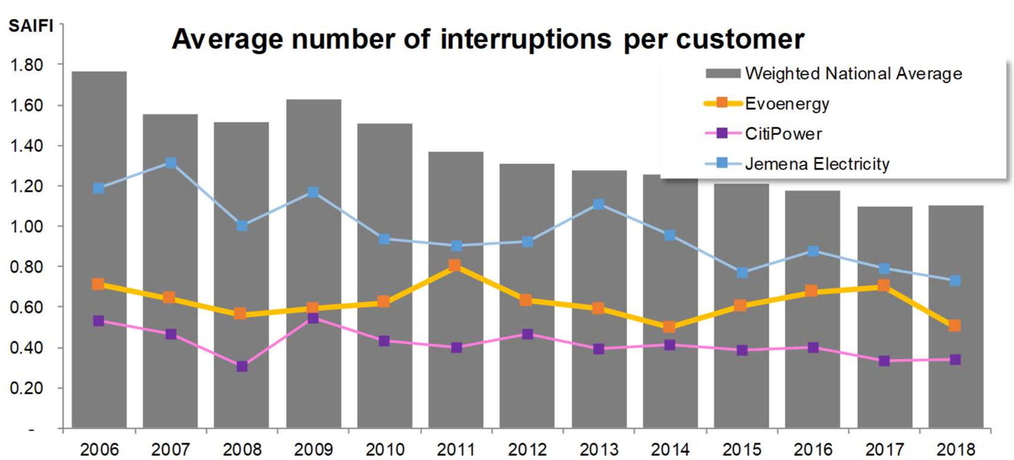

Figure 17 SAIFI performance compared to national average

It appears that the rest of the industry is gradually improving, but Evoenergy has remained one of the best performing electricity distributors in Australia. This may be partly due to its relatively small network size, the dense customer base (number of connections per km) and the degree of network interconnectivity – its performance is more aligned with performance of other small, urban networks such as CitiPower and Jemena Electricity. Evoenergy includes in its customer base important government institutions that have a national impact, and needs to maintain high reliability services to satisfy them.

The regulatory regime active in Australia retains a strong focus on performance, and Evoenergy, like all other distributors, must withstand scrutiny from the AER and its agents at 5-year intervals. In this environment, it seems reasonable to assume that past performance is a likely indicator of future performance, and that Evoenergy should be able to continue the performance it seems to have consistently achieved over the past 14 years.

2.8 Key findings

Evoenergy has planned substation enhancements to ensure that it is able to satisfy future demand, using current assumptions of population growth and demand per household. The forecast load on the network is around 68-69% of installed capacity by 2041. Noting that Evoenergy cannot operate at 100% of installed capacity (will rather need to operate at around 65-80% of installed capacity to account for credible contingency events), there is limited spare capacity available. The ACT's supply capacity is closely related to demand projections, and Evoenergy would be expected to continue to retain a prudent reserve. It could therefore be concluded that supply capacity will remain suitable based on current projections.

If electricity were to be used to substitute for natural gas, however, total energy demand would increase by at least 40-60%. Evoenergy's current plans do not provide for this scale of increase.

There are other factors to consider, and some of these are addressed later in this report. For example:

- Widespread use of electrical vehicles may add off-peak load but provide new mechanisms to manage demand peaks.
- The continued development of distributed energy storage, coupled with continued investment in rooftop and district solar generation options, may also enable peak demand to be minimised and therefore reduce the extent of the capacity upgrades needed in the supply network.

3.0 The Current State of the Gas Distribution Network

This section summaries the current state of the ACT's gas network assets. A map of the distribution network is presented in Figure 18 (ActewAGL Distribution, 2015)).

Figure 18 ACT gas network

This section draws from Evoenergy's recent submission to the Australian Energy Regulator (AER). It includes a summary of the gas pipelines and a projection of the value of the regulated asset base of gas assets (assuming that no further material investment will be undertaken).

Since current policies are likely to reduce or terminate the use of natural gas and Evoenergy has met operational targets with higher levels of gas demand, a review of gas supply capacity is redundant and has not been undertaken. The use of other forms of energy generation is assessed in Section 6.0.

Table 5 presents a summary of the gas network status, with asset quantities, life expectancies and asset values (where available) adapted from Evoenergy's June 2020 access arrangement proposal to the AER (Evoenergy Gas, 2020), (Evoenergy Gas, 2020).

Table 5 Network Overview

Asset Class	Asset Type	Quantity	Unit	Regulated Asset Value ($m)	Standard Useful Life (Years)	Mean Remaining Life (Years)
Pipelines	Transmission	53	km	$23	80	60
Pipelines	High pressure	221	km	$97	80	60
Pipelines	Low and medium pressure	4,282	km	$230	50	29
Regulators	City gate, field and district regulators	102	number	$15	15	8
Meters	Residential and indsutrial	135,394	number	$41	15	11

In general, Table 5 indicates that the gas network assets are relatively new and are on average in good condition.

Figure 19 presents this graphically using the same form of presentation used for the electricity network, showing mean asset condition, remaining service life expectancy, and RAB value by asset class.

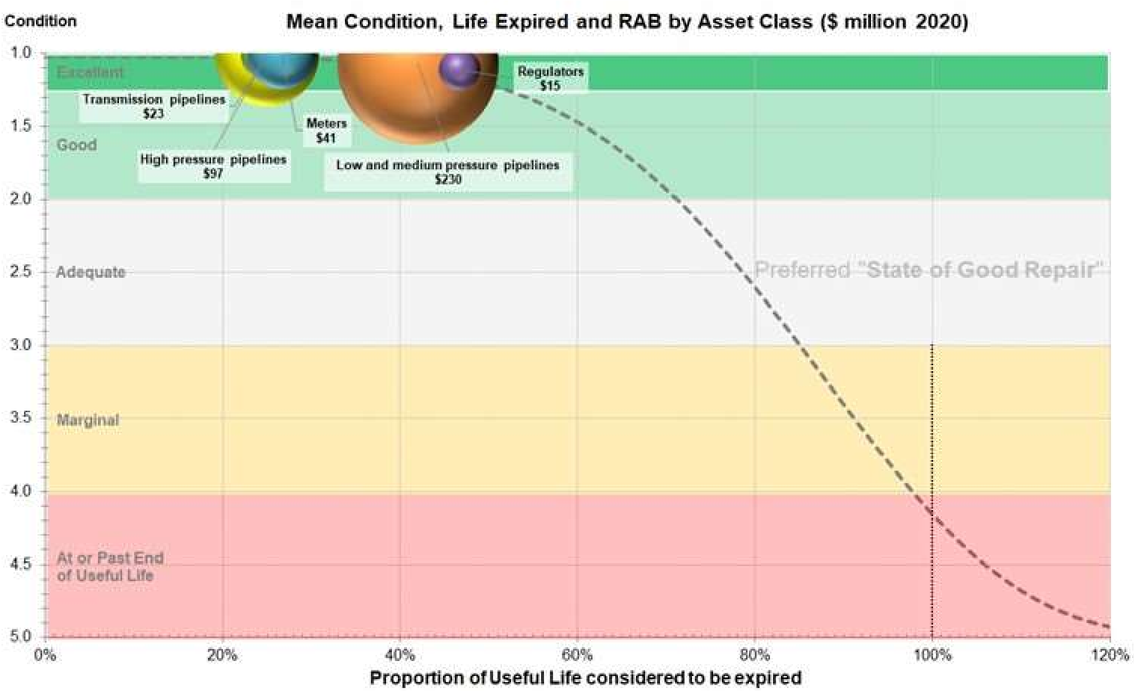

Figure 19 Mean Condition and Life Expired by Asset Class

Figure 19 shows that expected remaining life ranges from 60% (for low to medium pressure pipelines) to 75% (for high pressure pipelines).

The data provided by Evoenergy to the AER is aggregated by asset class and does not include more detailed data by service district.

3.1 Gas pipelines

Figure 20 presents the age profile of gas pipelines (ActewAGL Distribution, 2015).[7]

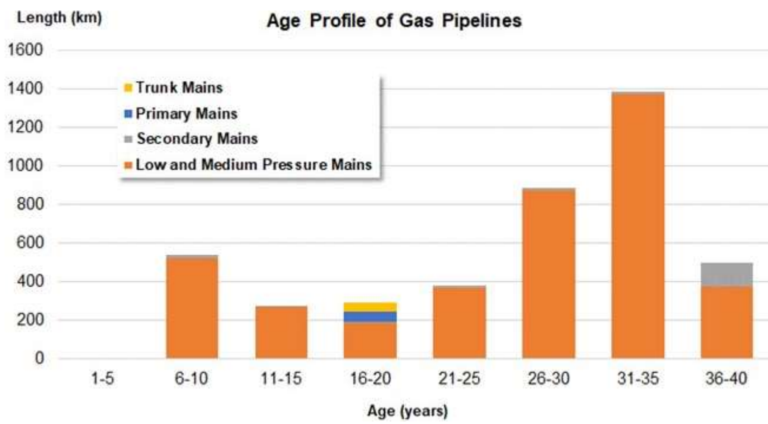

Figure 20 Age distribution of gas pipelines

No gas pipelines have yet reached nominal service life expectancy (50 years for medium pressure mains and 80 years for high pressure mains).

3.2 Regulated asset base

In the context of a policy to reduce emissions, the scale of asset impairment that might result from termination of the natural gas supply should be of interest. Figure 21 shows a simple estimate of the regulated asset base of gas assets projected forward to 2045, using published service life assumptions as reported to the AER in Evoenergy's 2020 submission, and assuming that no substantive investment would take place during the period (the assets are currently at an early stage of their expected service life) (Evoenergy Gas, 2020).

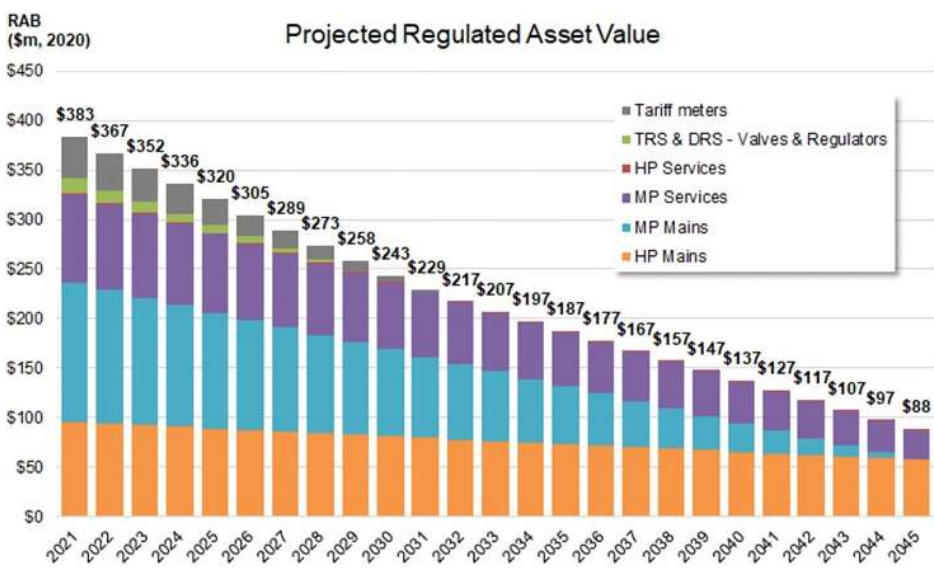

Figure 21 Projected regulated asset value

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[7] This analysis is based on data dated June 2015, extrapolated to the current period excluding asset acquisitions and/or asset renewals over the period.

The value in current dollar terms of the regulated asset base of the gas distribution system is estimated to decrease to $88 million in 2045, including $58 million of high pressure mains and $30 million of medium pressure services.

3.3 Performance of the gas distribution network

Evoenergy reported being compliant (for the 2018-19 reporting period) with its licence to provide gas distribution and connection services under the Utilities Act 2000, and being compliant to code requirements under the Utilities (Technical Regulation) Act 2014 (Environment, Planning and Sustainable Development Directorate).

Figure 22 presents unplanned outages over the FY11-19 period (Evoenergy Gas, 2020).

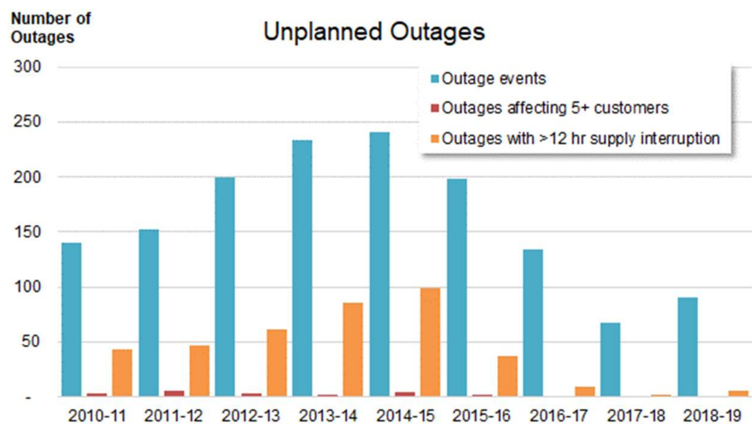

Figure 22 Unplanned Outages

In FY19, Evoenergy's target was less than 500 major unplanned outages affecting more than five customers (Evoenergy, 2020), but actual outages were far lower than this and none affected more than five customers in FY19. Figure 23 presents SAIFI, calculated per thousand customers per year. The SAIFI target for the FY22-26 period included in Evoenergy's June 2020 proposal is also included for context (Evoenergy, 2020).

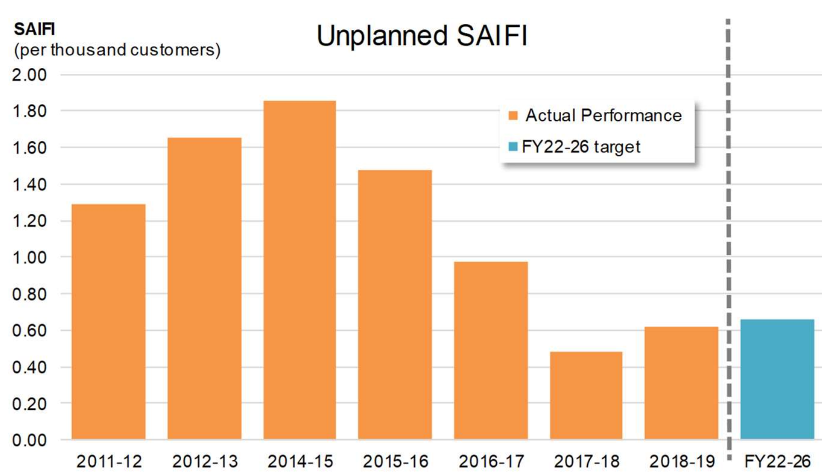

Figure 23 Frequency of unplanned interruptions per thousand customers per year (SAIFI)

SAIFI has decreased in recent years (FY18-19), and future targets are aligned with this recent performance. If the gas distribution system is terminated under current Government policy, demand for gas will reduce in the future and any performance issues will become less significant.

4.0 Energy Demand and Supply Capacity

The ACT uses energy delivered via natural gas and electricity distribution networks:

- The natural gas distribution system network delivered approximately 8.2 PJ (2,274 GWh) in 2018 (43% of total energy supplied).
- The electrical distribution network supplied 2,986 GWh in 2018 (57% of total energy supplied).

Data published by the Department of the Environment, Water, Heritage and the Arts (2008) indicates that approximately 78% of the gas energy supplied to households in the ACT is used for space heating (the remainder is used mainly for water heating and cooking). Energy demand from natural gas peaks during winter, and in 2018 the demand for gas peaked at about 60% of total energy demand, as indicated in Figure 24 (Evoenergy, 2020).

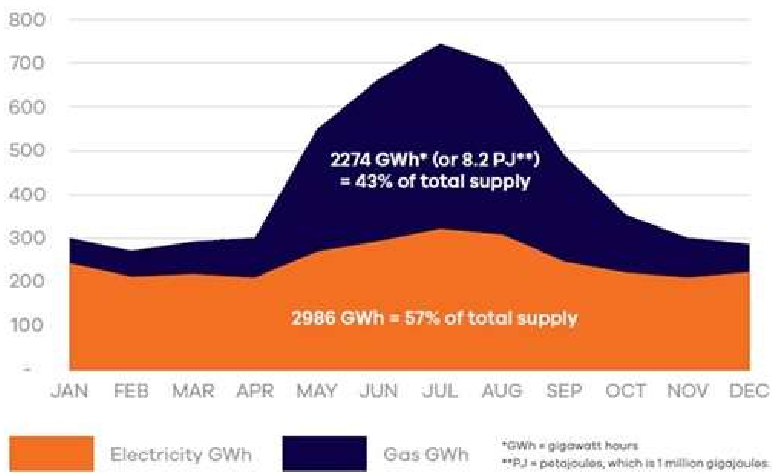

Figure 24 Energy demand in the ACT (2018)

Although the ACT population is projected to continue increasing, current Government policy in relation to emissions is expected to incentivise substitution of electricity for gas, reducing total demand for gas by about 10% over the 2021-26 period (Figure 25). (Evoenergy, 2020).

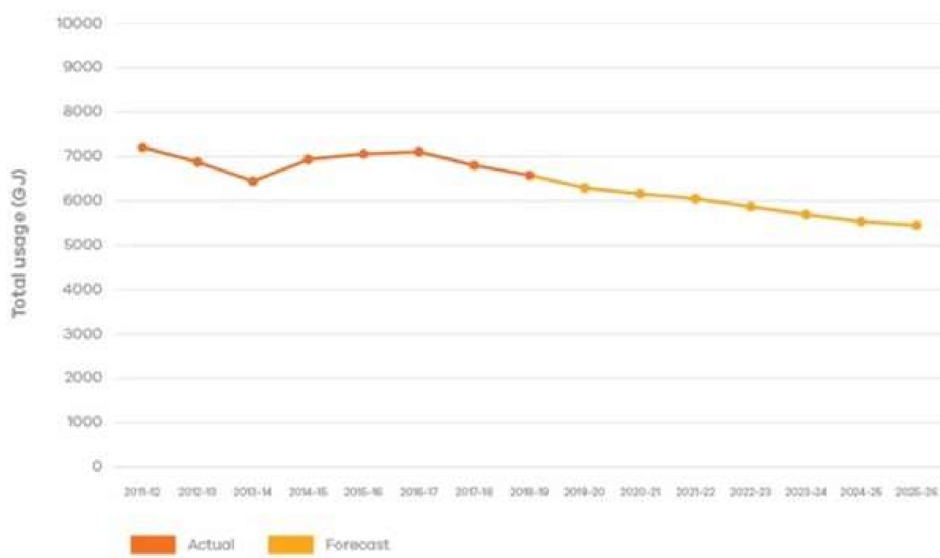

Figure 25 Historic and forecast gas usage

4.1 Energy Efficiency

Electric appliances are more energy efficient than the gas appliances which they would replace, however (Department of Industry, Science, Energy and Resources, n.d.). Reverse-cycle air conditioning systems, for example, are significantly more efficient than gas heaters. 10 megajoules of useful heat delivered using a reverse cycle air condition system (a 'heat pump') requires supply of 2.6 megajoules of energy, whereas delivery via a gas heating system requires 33.4 megajoules (Figure 26) (Beyond Zero Emissions, 2013). Other gas appliances (such as those used for cooking and water heating) are also less energy efficiency than their electric substitutes.

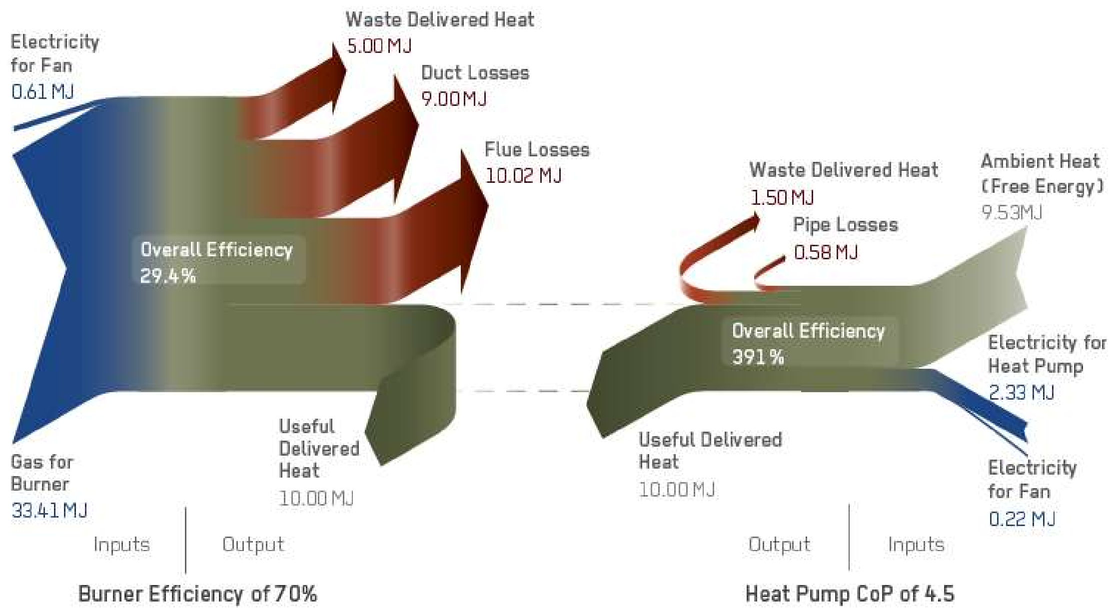

Figure 26 Efficacy of Gas Burner System Compared to Reverse Cycle Air Conditioner (Heat Pump)

4.2 The Energy Impact of Substituting Gas with Electricity

If the ACT Government's 2045 net zero emissions target is to be achieved by substituting electricity for natural gas, electricity distribution capacity will need to be increased. Gas provided about 60% of the July 2018 peak energy demand (Figure 25), which suggests that the supply capacity of the electrical network could need to be increased by around 150% to substitute for gas.

Replacement of the inefficient gas heaters with reverse cycle air conditioners (or similar heating systems) would significantly reduce the increase in energy required, however, and we estimate that the increase in electricity supply and distribution capacity needed to supply peak energy demand during winter (for the 2018 population of the ACT) would be in the range of 40-60%, assuming that:

- 78% of the gas energy supplied in 2018 was used for heating;
- Between 100% (lower limit of the range) and 25% (upper limit of the range) of current users of gas heating would replace them with split cycle systems;
- Other gas appliances are typically 85% energy efficient compared to equivalent electric appliances, and would be replaced with electrical appliances.

Other measures such as the introduction of more energy efficient appliances and peak demand management could further reduce the scale of that increase.

4.3 Energy Available from Rooftop Solar

The penetration of rooftop solar energy production in the ACT is currently about 16%, representing about 76MW of installed capacity. If 100% penetration could be achieved, the possible maximum generation capacity available (in summer) is likely to be less than 500MW (SolarQuotes, 2020).

Solar irradiation is reduced during winter, which is when the greatest demand for energy occurs (for heating), so the actual energy generated will be lower. It is clear, however, that a 100% rollout of rooftop solar energy generation at current panel efficiency levels will not provide enough generation capacity to substitute for all the energy currently served via natural gas.

Further, such a significant uptake in solar penetration is likely to lead to power quality issues and network instability (as discussed at Section 5.3). The network would not be able to support solar penetration anywhere near this level this without significant investment to support bidirectional energy flows in zone substations.

4.4 Other Sources of Energy to Substitute for Gas

We note in Section 6.2 that the feedstock for bioenergy production in the ACT is limited, and the likely maximum supply capacity is only around 3% of the ACT's energy demand. Bioenergy cannot therefore be considered a complete substitute for natural gas.

We review in Section 6.1 the potential for green hydrogen to be used as a substitute for natural gas:

- Current gas appliances will continue to work effectively with hydrogen blended with the natural gas up to about 15% only, so hydrogen cannot completely replace the gas.
- Green hydrogen production (using electrolysis) is currently 60% - 80% efficient (depending on the technology used). While hydrogen could be considered a potential substitute for natural gas, in practice it is not a viable alternative to electricity (the solar generation capacity required to manufacture hydrogen would be more cost effective and energy efficient if used directly by consumers).
- Grid-scale hydrogen storage via fuel cells has a relatively low round trip efficiency (in the range 30-40%) compared to other commercially viable technologies (such as utility scale battery storage, which has an efficiency in the range 85-95%).

5.0 Strategies to reduce energy emission - Electricity Distribution Network

The electrical network in the ACT is operated by Evoenergy and covers an area of 2,358 km^2, serving a population of about 420,000 with over 2,300 km of overhead lines and 2,600 km of underground cables. Net peak demand of the network is 587 MW (Evoenergy Gas, 2020).

The strategies that the ACT Government uses to transition toward zero emissions may have a positive or a negative impact on the existing electricity distribution network. These potential impacts have been grouped into three main themes for the purposes of this study:

- The increasing penetration of electric vehicles for private and public use.
- The impact of increasing distributed energy sources on the distribution network
- The implementation of district heating.

5.1 Electric vehicles

In 2020, transport was estimated to cause more than 60% of the ACT's emissions, mostly via fossil fuel use by private cars. The transition to zero emissions vehicles is a key focus of the ACT's transport and climate strategies, and a global shift toward zero emission vehicles is underway - the United Kingdom and France intend to ban sales of new petrol and diesel cars by 2040, for example, and some car manufacturers (such as Volvo and General Motors) intend to phase out fossil fuel powered vehicles (ACT Government, 2018).

The main types of passenger electric vehicles (EVs) are presented in Figure 27 (ACT Government, 2019).

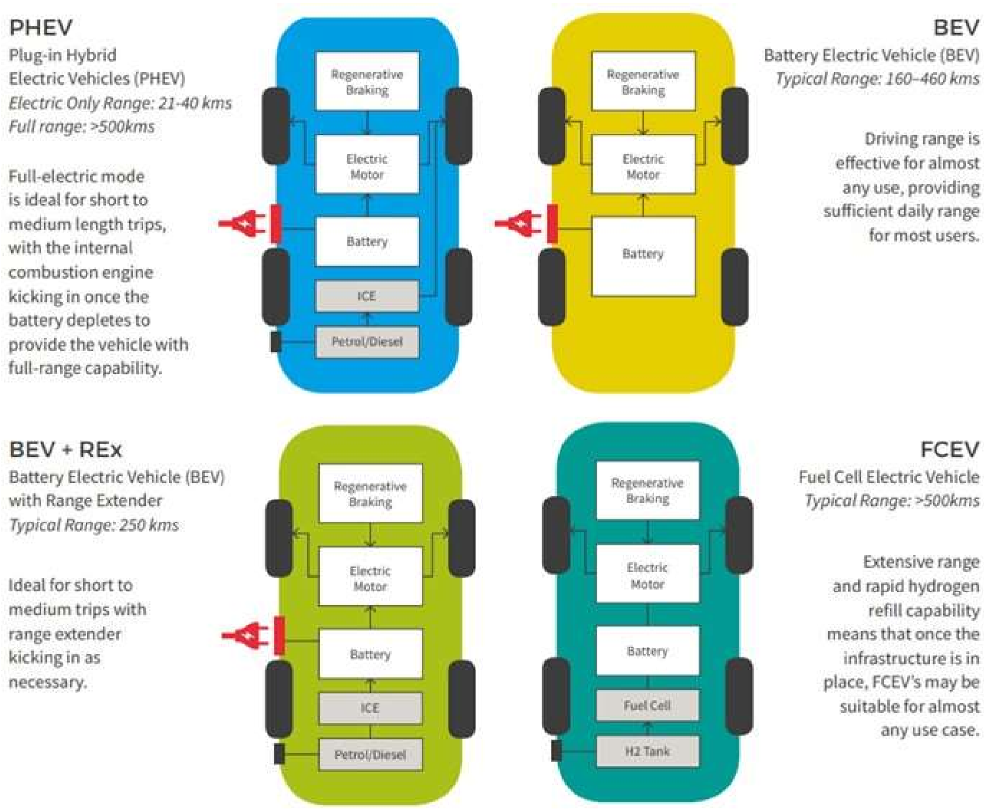

Figure 27 Types of Electric Vehicles

Bloomberg estimated that the ownership cost of EVs for private use may reduce below that of fossil fuel vehicles as early as 2024, which suggests that a rapid transition could occur after then as the current fossil fuel fleet is traded in (Bloomberg New Energy Finance (BNEF), 2019). An uptake in EV use presents challenges to the existing electricity distribution network, and the impact of EVs will depend on interrelated factors including:

- The impact of driver and charging behaviour on peak loads (which differs for different EV use cases);
- Requirements and distribution of charging infrastructure;
- Demand management strategies like smart charging, planned placement of charging infrastructure, the use of Vehicle-to-Grid (V2G), Vehicle-to-home (V2H) and alike technologies;
- The capacity and configuration of the existing distribution network.

Driving and charging behaviours

Figure 28 shows the charging patterns of household and fleet EVs in a Victorian Government trial. Household EVs generally charge at night (which roughly aligns with existing peak periods), while fleet EVs tend to charge during business hours (EVENERGI, 2019).

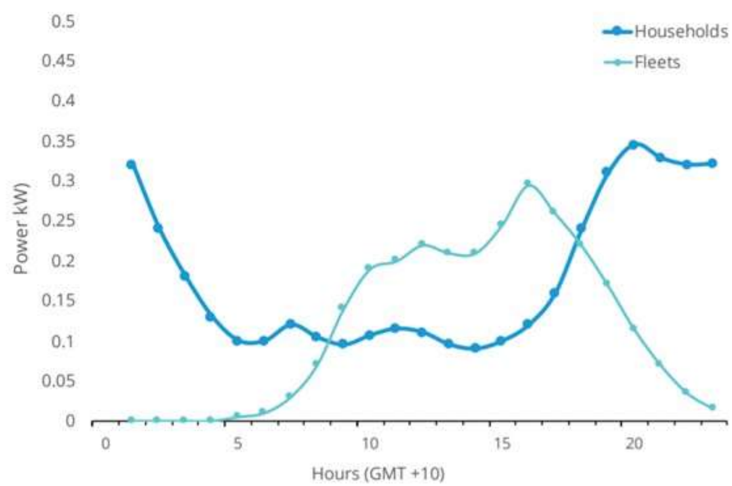

Figure 28 EV Charging Demand Profiles for Fleet and Households (Victorian Government EV Trial)

It is estimated that in an unmanaged charging scenario (where 80% of EV users charged at peak periods), total peak demand of the National Energy Market could increase by 1.9GW by 2030. EVs could be charged during the off-peak period, however, using demand management strategies like smart charging, which would decrease peak demand and increase the utilisation of existing network capacity (AECOM, 2011) (Mullan, Harries, Braunl, & Whitely, 2011). The cooler temperatures during off-peak, night-time charging allow assets like conductors and transformers to take a higher load without being damaged (AECOM, 2011).

There is potential for the energy needed to charge EVs to be supplied by renewable energy generation if market arrangements and infrastructure are in place to enable the matching of supply with demand. AECOM estimates that by 2030, EV energy demand would represent around 13% of total renewable energy generation in the NEM (AECOM, 2011).

A typical household is estimated to require around 2kW of solar panels to provide the energy required to charge an EV (assuming that the average Australian drives around 50km per day, and that this energy is stored), in addition to normal household energy demand (Peacock, 2020).[8] Solar PV and distributed energy resources is discussed further in Section 5.2.

The first EV trial conducted in Western Australia (WA) found that fleet charging peaked around 3pm and the aggregate profile of fleet charging closely resembled a solar PV curve. This highlights the opportunity for daytime peak demand to be offset by renewable energy sources (Speidel & Braunl, 2014).

Charging infra-structure

An uptake in EVs is likely to be accompanied by an increase in charging demand and infrastructure. Capacity constraints may occur where a cluster of EVs are charged, and are likely to exist at the street transformer and feeder level where capacity size and load diversity is lower (EVENERGI, 2019).

The cost of capacity upgrades is likely to increase for low voltage parts of the network as the quantity of assets (length of line) per customer increases further down the supply chain (AECOM, 2011).

Table 6 summarises the levels of charging for EVs (Queensland Government, 2018).[9]

Table 6 Levels of EV Charging

Category	Power / Voltage	Typical charge times	Typical locations
Occasional charging (level 1)	Standard power outlet		Homes (shifting away from occasional charging)
Basic AC charging (level 2)	2.4-7kW 10-32A	Min. 2 hours to overnight	Homes, workplaces, apartments
Destination AC charging (level 2)	11-22kW 16-32A	30 minutes to 2 hours	Shopping centre, public parking areas, commercial fleet parking
Fast DC charging (level 3)	50kW-150kW	20 minutes to an hour	Inter-regional routes or areas with high demand for fast charging
Ultra-fast DC charging (level 3)	150kW-350kW	5-20 minutes	Major highways routes

While the majority of private EV charging is likely to occur at home, range anxiety and the commercial use of EVs (for transit and long-distance driving) would create demand for availability of fast charging infrastructure. There will therefore be a market for a network of fast charging stations (FCS) to satisfy the EV driver's need for a quick, full recharge (Speidel & Braunl, 2014). This demand can be seen in current fast charging investments like the Queensland Electric Super Highway (Queensland Government, 2018) and the launch of Shell's network of 80 charging stations across Europe (EVENERGI, 2019).

FCS (refer to Table 6) is likely to be located in purpose-built commercial/industrial sites with proximity and land requirements similar to petrol stations (Speidel & Braunl, 2014).

The widespread deployment of FCS may decrease the amount of charging needed at any one time, helping to spread charging and relieve the pressure of evening peak loads (AECOM, 2011)

[8] Estimates by SolarQuotes assumes that the average EV will travel 6km per 1kWh and that 1kW of solar capacity will produce on average per day over the year 4kWh of electricity.
[9] Levels of EV charging derived from Queensland Government practice note and may differ slightly for the ACT.

It should be noted, however, that the high charging loads of FCS may negatively impact the voltage stability, reliability and incidents of power loss of the distribution network (Deb, Tammi, Kalita, & Mahanta, 2018). Figure 29 depicts the volatile and spikey load profiles of FCS. (Engel, Hensley, Knupfer, & Sahdev, 2018).

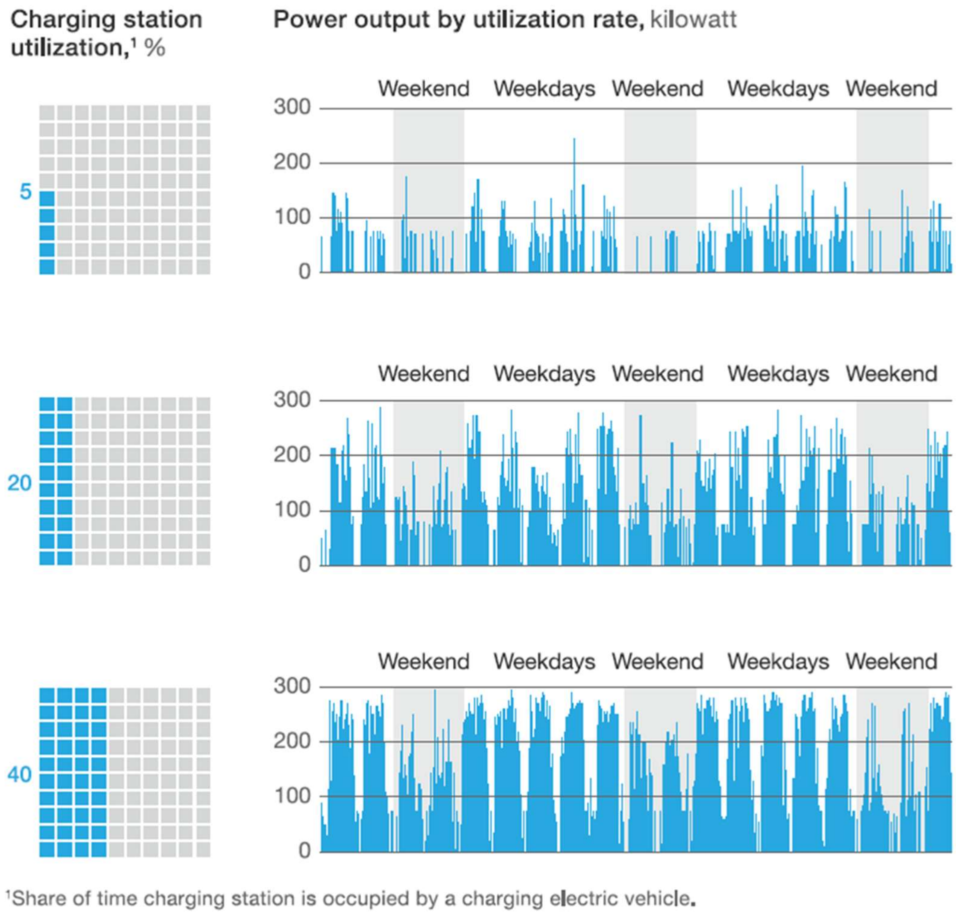

Figure 29 Simulated load profile of a FCS

Coordinated planning and placement of FCS is needed to minimise degradation of voltage profile, increases to peak load and harmonic distortion. The need for network upgrades to ensure network reliability will depend on capacity and voltage stability of the network where the FCS is located (Deb, Tammi, Kalita, & Mahanta, 2018). In mapping the network of the Queensland Electric Super Highway, the Queensland Government considered EV driving ranges, the opportunity for FCS to be supplied by renewable energy, and the spare capacity of the local network in order to minimise additional infrastructure costs (Energy Queensland, 2016)

The high-power demand of FCS means that stations may require an upgrade of distribution assets such as transformers near the point of connection. FCS may require on-site facilities to ensure load quality (AECOM, 2011).

The use of energy storage to smooth peak loads is becoming more attractive economically as the cost of batteries continues to decline. Co-locating a FCS with an energy storage unit that charges during periods of low demand and discharges at peak times could reduce peak load and avoid grid upgrades (Engel, Hensley, Knupfer, & Sahdev, 2018). Additional benefits can be realised if the energy storage unit provides ancillary services to the distribution network, which is discussed further below.

Energy storage is discussed in Section 5.3.

Potential future uses of EVs

With continuous developments in battery technology and an uptake of EVs in the market, EVs could be considered as large flexible loads that provide benefits to the network.

V2G / V2H technology uses a bi-directional energy flow between the EV battery and the grid or household to provide a flexible energy supply and energy storage capacity. When connected to the grid, consumers are able to charge their EVs during off-peak periods and discharge energy back to the grid during peak periods. This offers the same flexibility benefits as smart charging (where the impact of EV charging on peak loads can be minimised) as well as decreasing peak load during high priced interruption events like maintenance after an asset failure or during a critical peak load.

EVs connected to the grid could also act as power reserves to maintain the frequency and voltage of the grid when imbalances or congestion occurs. This service is normally done by providers on the Frequency Control Ancillary Services (FCAS) market and may present a financial incentive for EV owners (AECOM, 2011).

To date, V2G / V2H technology has been largely non-existent in the Australian market, however the benefits have been demonstrated through small trials. In 2013-14, AusNet and CSIRO conducted a trial with an 11.8kWh battery capacity EV which was driven a daily commute and plugged in each evening. The trial found the available energy that could be exported from the EV ranged from 0.7-5.5kWh for 40 minutes to five hours (AusNet Services, CSIRO, 2014).

ARENA is launching the Realising Electric Vehicle-to-Grid Service project that will install 51 bi-directional chargers and deploy 51 V2G capable EVs in the ACT. The project will monitor a range of electric parameters to test the delivery of FCAS at a fleet scale (ARENA, 2020).

The ACT currently has about 340,000 registered vehicles (ACT Government, 2019). If all of these were converted to EVs, their V2H capability would represent a total battery storage capacity of up to 6.8GWh, some of which could potentially be utilised to offset peak demand. The impact that total battery storage capacity may have on supply power during peak demand may be constrained by the residual charged state of the EV during or after use during the day.

A challenge for V2G / V2H technology is the long-term cost of accelerated battery replacement as a result of the higher number of charging cycles. EV batteries typically have a cycle life of approximately 5000 and an expected life of 13.6 years on a simple daily deep charging cycle. Increasing this to two deep cycles (for daily charging and home or grid consumption) can decrease expected battery life to 7 years (Graham & Brinsmead, 2016)

Battery swapping stations (BSS) takes the Battery as a Service (BaaS) approach to demand management and public charging infrastructure. This is an alternative recharging option to FSC that allows drivers to exchange depleted EV batteries for charged ones in minutes at dedicated stations and could provide similar benefits to the network as provided by V2G / V2H technology (for energy storage). The BaaS model could potentially be applied to meet the energy requirements of a variety of industries such as manufacturing (Clean Energy Global, 2019).

BSS has had limited traction in Australia following the bankruptcy of Better Place[10] in 2013, as manufacturers appear unwilling to take part due to intellectual property issues (Energy Supply Association of Australia, 2013). The technology has success in China where Chinese EV manufacturer Nio recently celebrated its 500,000th battery swap (Ridden, 2020).

[10] Better Place was an EV charging network offering battery swapping facilities to members. Around 12 charging stations were rolled out in Canberra before the company went into liquidation in 2013.

Nio's BaaS plan allows consumers to save on the purchase price of the EV (AUS $14,128) by renting the battery for a monthly price. Nio claims that this new service removes the cost of battery degradation for owners, allows on-demand swaps, and ensures battery servicing and upgrades (Guthrie, 2020). BSS and the BaaS approach may have potential in Australia if it can overcome these market barriers (Ridden, 2020).

EVs for public use (electric buses)

There is interest in EVs for public use. The ACT Government recently conducted a 12-month trial using two electric buses. The buses took six hours to charge (from zero to full charge), but this did not constrain the trial as the two buses could be scheduled to accommodate charging requirements (Transport Canberra, 2019). On a larger bus network, however, charging requirements may be an operational constraint and increase peak loads.

The impact of electrifying the bus network will depend on the battery technology (battery weight to driving range ratio) and the type of charging infrastructure required to operate the bus network.

The feasibility of operating an existing bus network (made up of 15 diesel buses that cover 247.2km^2 in Belleville, Ontario) was recently assessed using Battery Electric Buses (BEBs). The study examined the impact of fast, opportunity and overnight charging, which differ in range, size, charging location and charging profile, on the distribution network.

The study found that fast and opportunity charging was more operationally feasible than overnight charging (especially for longer routes) but had substantial impact on the network including:

- Fast and opportunity charging substantially impacted the substation transformer and distribution feeder through overloading, voltage regulation and other quality aspects;
- Intermittent loading caused excessive wear and tear of load controlling devices; and
- Fast and opportunity charging required a service transformer 5-6 times the size of one used for overnight charging (Mohamed, Farag, El-Taweel, & Ferguson, 2016).

The impact of the use of bus depots for charging will vary depending on the number of buses, the bus duty cycle and the charging window. A study on electrifying Auckland's bus depots found that the depots reduced spare capacity of the network in some areas but increased it in others. The overall impact on peak demand was relatively low (2%) due to off-peak charging, but the effect on demand was exacerbated by geographic concentration. This suggests that the depots may cause localised problems and require network upgrades.

Investment was required to upgrade the substation (resizing of transformers to cope with higher loads) and high voltage cable to connect the depots to the primary substation.

Substantial upgrade costs may be mitigated by charge management strategies and onsite power storage / generation (Element Energy Limited, 2018).

Case Study: Waterloo Bus Depot, London

In 2016, 51 buses were upgrade to electric and charged at the bus depot (the Waterloo garage). It was assumed that this development would require a network upgrade to charge all buses, however capacity constraints in the local HV network meant that UK Power Networks was unable to provide an upgrade connection for nine months. A timed demand connection was implemented allowing the customer to draw the required 2.5MW in the off-peak and 0.5MW during the day for charging a small number of standby buses and topping up buses between routes. This postponed the need for a connection upgrade at the site (UK Power Networks, 2018).

There are challenges in minimising the impact of EVs on a distribution network:

- A lack of (enforced) national standards could lead to the import of EVs and charging technology that have differing requirements and are not compatible with one another. This can be challenging for effective management of charging demand (Speidel & Braunl, 2014).
- Developments in the EV market and the mix of charging infrastructure may make it difficult for electricity distributors to ensure that the network has sufficient capacity. Thorough planning and a combination of approaches is likely to be needed, including smart charging, pricing signals to encourage off-peak charging, targeted upgrades to the network and FCS location planning.
- The context of vehicle usage in the long-term needs to be understood. Increased ride-sharing and potential autonomous vehicles is likely to have a major impact on demand (EVENERGI, 2019).

5.2 Hydrogen-powered vehicles

Hydrogen is increasingly being explored as an alternative fuel source. The Council of Australian Governments (COAG) Energy Council has set a vision for Australia to become a major player in the global hydrogen industry by 2030.

There is interest in using hydrogen to power heavy vehicles (like trucks and buses) that travel long distances because hydrogen fuel carries more energy than the equivalent weight of batteries (approximately 1kg of hydrogen is required for every 100km travelled)[11] (COAG Energy Council, 2019). If global policy shifts to support the decarbonisation of the industrial sector, hydrogen may potentially be competitive with diesel fuel for use in long-distance haulage by 2031-34 (AEMO, 2020).

The main barriers for an uptake in hydrogen in the heavy trucking industry is the capital cost of FCEVs and the lack of infrastructure. Hydrogen refuelling stations would be need to be established across major freight lines, potentially utilising existing service stations and truck stops, which may require new network upgrades or infrastructure (AEMO, 2020).

Hydrogen can be produced from clean energy sources via an electrolysis process (which uses energy to split water into oxygen and hydrogen) with no carbon emissions. Electrolysis and the application of hydrogen is discussed further in Section 6.0. The production and distribution of hydrogen for transport is associated with significant efficiency losses. Figure 30 presents a comparison of the energy-to-wheel efficiency of hydrogen vehicles compared to BEVs. FCEVs require around 2-3 times more electrical energy than BEVs (Volkswagen, 2019). Stated differently, FCEVs require up to three times as many solar panels to travel the same distance (Alternative Technology Association, 2019).

[11] Hydrogen requirement based on Hyundai Nexo and may vary for different sized vehicles.

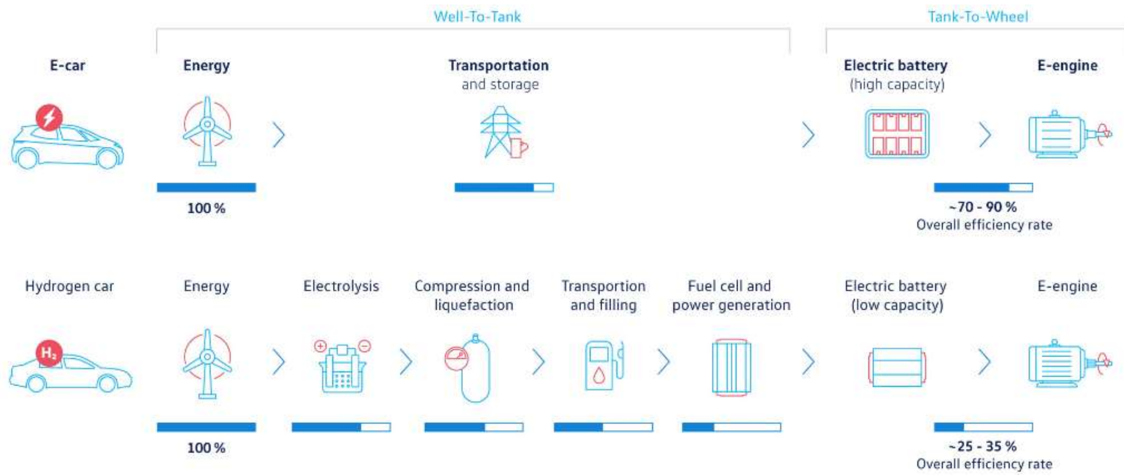

Figure 30 Efficiency of Hydrogen vs Electric Vehicles

The scale (utility or distributed) and geographic location of electrolysers will change the impact that hydrogen has on the distribution or transmission network. Well placed electrolysers (matched with suitable energy supplies) could be used to manage load profiles ramping up or down to shift loads and reduce curtailed energy (AEMO, 2020).

Figure 31 provides a simple depiction of how a hydrogen production facility could interact with the electricity network to reduce peaks and use surplus solar power generated during the day (the power consumed for hydrogen production is shown by the arrows). (GHD Advisory, ACIL Allen, 2020)

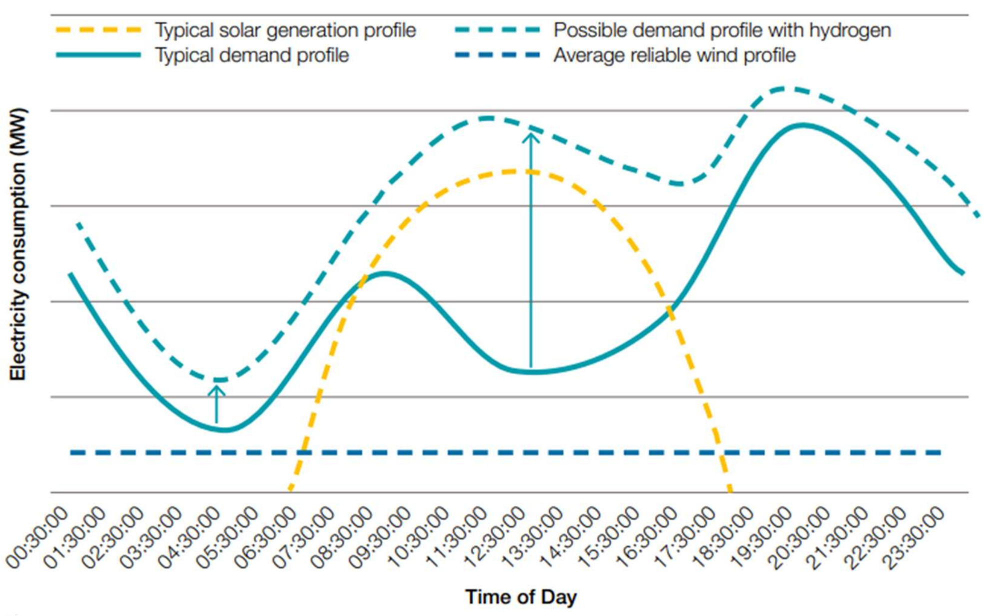

Figure 31 Simplified hydrogen load-following generation

Load profiles may change depending on the volume of hydrogen produced and the commercial viability of the facility (in Figure 31 the facility would produce hydrogen at well below the capacity of the electrolyser for most of the day).

Other potential opportunities including designing electrolysers that are connected to the transmission network for FCAS or connecting electrolysers through particular inverter designs to offer voltage support services to the transmission or distribution network (AEMO, 2020).

5.3 Distributed energy resources

Distributed energy resources (DER) are small, local power sources that can be used individually or aggregated to serve the grid. DER technologies can include solar photovoltaic (PV) installations, wind turbines, microgrids, energy storage, backup generation and combined heat and power systems. AEMO projects that DER could provide up to 13% to 22% of total underlying annual NEM energy consumption by the end of 2040 (AEMO, 2020).

Growth in DER is primarily driven by increasing levels of solar photovoltaic (PV) installations. Figure 32 shows growth in NSW and the ACT, with the different colours representing different sized installations (Institute, 2020). As DER continues to grow, the AEMO forecasts that there will be relative reductions in large-scale solar developments for NSW and ACT beyond the early 2030s (AEMO, 2020).

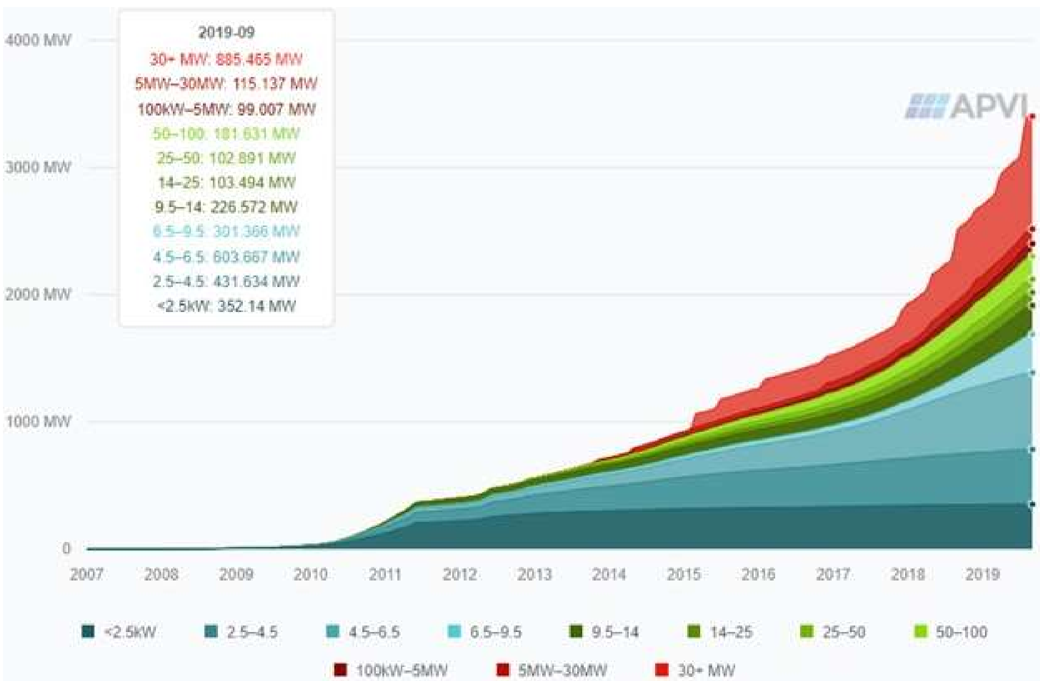

Figure 32 Cumulative solar installations – NSW and ACT

The increasing number of PV installations and other DER connected to the grid has the potential to cause negative impacts in distribution systems which were not designed to cater for these energy sources or the bi-directional flow of power. Issues may include:

Peak demand impacts	Rooftop solar PV reduces the need for other energy generation during the day when production is high and demand is relatively low, and energy not used by the resident directly can be fed back into the grid. In Australian conditions the energy peak is generally in the early evening, however, so rooftop solar (without storage) is not effective at meaningfully reducing peak system demand (Smits, 2018). The indicative load chart in Figure 33 shows that demand from the grid typically becomes peakier with the introduction of solar generation. This means that traditional baseload generation facilities need to remain active to meet this peak demand but are underutilised during the day (Smits, 2018). This can have the unwanted result of forcing an increase in generator charges (to recover fixed costs).

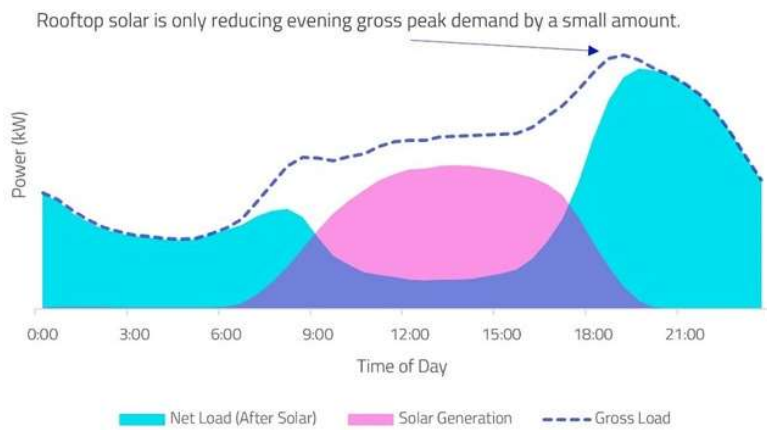

Figure 33 Indicative Solar Load Chart – South Australia

To further demonstrate this, Haghdadi et al conducted a case study using Sydney data to examine the potential impact of PV on peak demand. The study found that peak demand could be reduced by up to 5% for PV penetration of up to 15%.

The three-year study found significant variability in the results due to changing load profiles and PV performance patterns over the period. As PV penetration increased beyond 10-20%, peak reduction diminished and effectively reached zero where penetration exceeded 30% (Haghdadi, Bruce, MacGill, & Passey, 2018).

As solar PV penetration becomes higher, net load may move into the negative during peak solar generation times, meaning some states become net exporters of energy. AEMO forecasts a negative minimum demand for South Australia under certain conditions in the 2020-30s, for example (AEMC, 2017). For some states, rooftop solar is predicted to meet 100% of generation needs during the day on low demand days, but peak demand is unlikely to be heavily affected. Network infrastructure and generation must still be designed to meet peak demand (and to mitigate the risk of low PV generation during times of cloud cover).

The introduction of energy storage into the distribution system is a potential solution to this issue by storing excess energy generated during the day and releasing it during periods of peak demand. Various forms of storage at different stages of the network and benefits and impacts are discussed in the following sections.

Research has shown that the introduction of both PV and energy storage into a network has the potential to reduce peak demand (in both the residential and wholesale market) to a point where the resulting reduction in network investment could potentially outweigh the loss of revenue associated with the increases (Young, Bruce, & MacGill, 2019).

Power quality

The intermittent nature of DER generation has been associated with power quality issues, such as overvoltage and overcurrent, particularly during times when locally generated power exceeds the local load and this power is exported to the grid. These issues can result in premature equipment/appliance failure and have the potential to reduce supply reliability.

Increased penetration of distributed energy generation such as PV has the potential to impact the grid’s ability to meet power quality requirements (Brinkel & Gerritsma, 2020). Utilities are having to find ways to maintain grid stability while power is flowing in the reverse direction (HVPower, 2005), and these measures can be costly.

The impact depends on a number of factors, including PV capacity deployed, load level in the electrical neighbourhood and the type of voltage control assets in use (Dubois & Flinn, 2015). Watson et al examined the potential over-voltage effects of solar PV on distribution grids in New Zealand and found that over-voltage problems can be expected in the future, particularly in urban areas, with significant increases in PV penetration. In most cases, though, with voltage management mechanisms in place the overvoltage would not exceed the NZ statutory limit (Watson, et al., 2015).

A technical analysis approach, known as hosting capacity analysis, can be used to determine the maximum amount of DER that can be integrated at specific locations in the distribution grid while maintaining network performance and quality of power supply (Energy Networks Australia, 2017). A Hosting Capacity Study of Victoria's LV networks found that without capital investment or voltage management, PV penetrations had varying impacts:

- 7/10 LV networks experience power quality issues at low PV penetration levels (below 25%), however 2 networks never experienced a breach of voltage requirements even at maximum PV penetration
- 6/10 networks would spend more than 8 hours per day breach voltage requirements at PV penetrations above 40%
- 3/10 networks experienced a voltage rise of more than 50V at PV penetrations above 40%, however 4/10 networks experience moderate (below 6.V) rises at PV saturation.

The study also found that distribution transformers' step-down voltage was a fixed ratio for delivery to LV network customers, meaning that the high voltage on the HV network would be passed onto the LV network. With a moderate PV uptake, voltage rise within the LV network can compound with rises at the HV level and potentially reach extremely high levels without intervention. The range of impacts that solar PV has on the network shows that no single solution can be applied across the LV network to improve hosting capacity. Measures employed by distribution system operators to mitigate power quality problems need to be highly sensitive to local network characteristics (ENEA Consulting, 2020). These measures can include:

- On-load tap changers at transformer stations that can be used to control voltage in the LV grid. These are unable to mitigate rapid voltage fluctuations, however, and can increase both capital and maintenance costs.
- Transformer upgrades/reconductoring to include an off-load tap changers that can manually adjusts the voltage ratio between the HV and LV network based on network conditions.
- LV regulators that use a controllable transformer to increase or decrease voltage on LV networks
- Reactive power control and export limits on PV inverters (but these may reduce inverter life).
- Energy storage systems and behind-the-meter batteries – community batteries and capacitors – as discussed further in the following sections.
- Electric Vehicles, which could act as flexible loads when connected to the grid to help mitigate fluctuations (as discussed in Section 5.1).

The Host Capacity Study compared the technical and economic (cost) benefits of these mitigation measures at different levels of PV penetration on the Victorian LV network. Figure 34 summarises the results of this analysis.

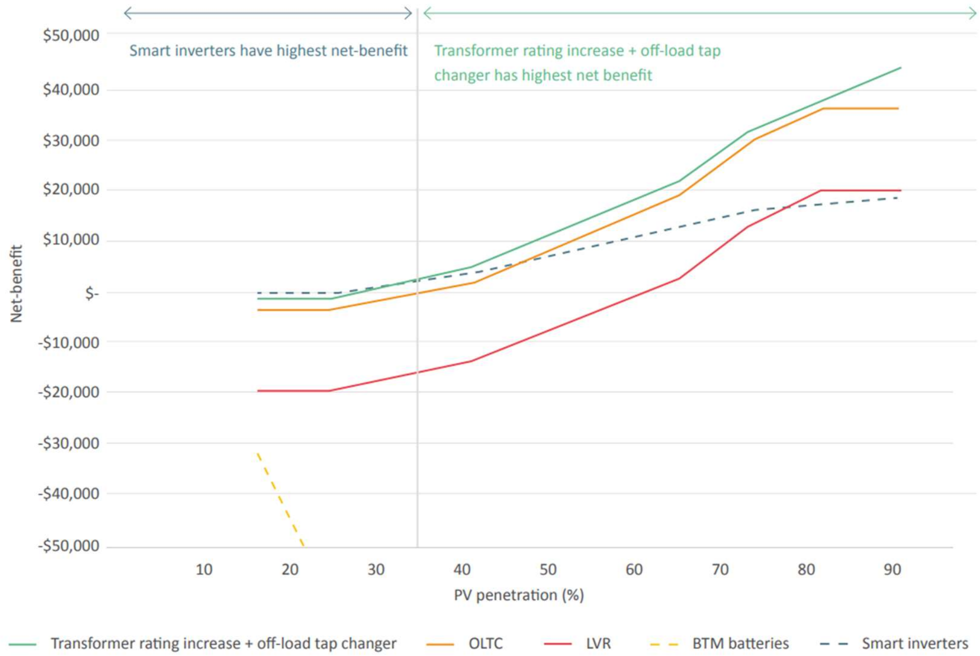

Figure 34 Comparison of Power Quality Mitigation Measures

Transformer aging The service life of transformers and cables in the distribution system is dependent on the duty and operating conditions within the system.

The possibility that overloading from increasing penetration of PV systems could accelerate the aging process of these components and reduce overall service life was explored by Ucar et al (Ucar, Bagriyanik, & Konnurgoz, 2017).

Findings from two case studies conducted by Ucar and Jimenez suggest that low power factors associated with presence of PV do not overstress the distribution transformers under certain conditions. Jimenez suggests that as long as the PV systems provide a high-quality current waveform, non-active power in the transformer will remain the same, and a reduction in active power (where the active power produced by the systems is consumed by the households) may contribute to an extension of operational life of the transformers and therefore deferred capital investment (Jimenez, Calleja, Gonzalez, Huacuz, & Lagunas, 2006).

Distributed energy storage in household or as community facilities can help to address some of these issues:

Household storage A study by ARENA suggests that the implementation of solar and storage systems at the residential level has the potential to reduce peak demand by up to 7-14%, and subsequently delay network investment by 4-14 years, depending on penetration (ARENA, 2017). The study estimates that greater benefits could be realised. However, the current price of batteries may make this an unattractive investment for homeowners.

A BaaS approach toward peak demand management in the housing sector was studied in 2016. The study examined the economics of a mass introduction of batteries into houses in the UK that had solar PV and found that it was not economically feasible at the time without heavy government subsidies (Davis & Hiralal, 2016).

The Grattan Institute estimated that an average home requires a 7kW solar system (on about 70m^2 of clear roof space, preferably north-facing) and a 35kWh battery storage pack to achieve 95% solar power supply reliability (Grattan Institute, 2015)

Community energy storage

Community Energy Storage (CES) is storage connected at the distribution feeder level and associated with a cluster of customer load (Commission). This definition is a broad one and in practical terms can encompass a number of implementation approaches, uses and subsequent benefits. Figure 35 shows how CES could be integrated into the distribution network (Abi-Samra, 2013).

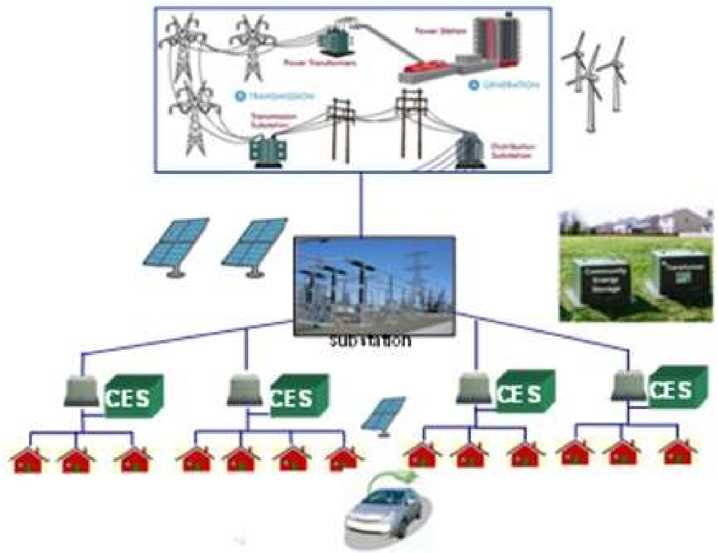

Figure 35 Schematic of Community Energy Storage

CES's major benefit is to manage supply and demand mismatches that can occur with distributed energy resources (DER), and therefore allow deeper penetration of renewable energy sources into the generation mix (Petta & McConnell).

Implementation can be driven several different factors including:

1. Capacity to store excess generation from DER;
2. Higher penetrations of intermittent renewable resources (through load levelling and smoothing); and/or to
3. Provision of backup power during outages.

CES could be fully community owned or may be developed in partnership between public and private agencies.

The impact of CES on the network will depend on the drivers for it and how it is used:

Distribution loss reduction

Increased penetration of DER has seen a shift in the distribution network from a passive to an active distribution network. This transition presents operational challenges (as discussed in the previous section), including high power losses, reverse power flow, voltage fluctuations and poor power quality.

The distribution network has the highest losses in the electrical power system, with losses accounting for 6-8% of peak load. Energy storage has the potential to reduce energy losses through load levelling, with the highest potential for loss reduction occurring when peak shaving can be distributed across several locations (Sardi, 2017).

Loss reduction potential is a significant factor to consider when determining the location of CES, as well as optimal size and power factor. Considering these factors with CES and PV together can help to optimise loss reduction and enhance voltage stability. The highest loss reduction is obtained when CES is located near to the load. In addition, CES near PV units enables higher PV penetration, while maximising energy loss reduction (Junainah, Nadarajah, Hung, & Bhumkittipich, 2015).

Peak Demand Impacts

Introduction of PV with battery storage has been demonstrated to reduce peak demand from the grid by between 10% and 16%, with the highest reductions occurring in hotter areas. Battery storage would enable households with PV installed to store their own surplus energy from daytime generation when demand is low (instead of selling it back to the grid) and use it later on when demand is higher, reducing their demand for grid electricity and reducing energy costs by avoiding peak tariffs.

A case study undertaken in Seoul, South Korea suggests that in areas with existing DER, peak demand shaving with CES adoption can achieve 9% peak demand reduction with the installation of a 270kWh energy storage system. When additional distributed storage systems are integrated, peak demand shaving can achieve up to 14% reductions in peak demand (Park & Park, 2017).

The reduction potential of CES means that other network investments for grid upgrades could be deferred as peak demand to be catered is reduced.

Increased Reliability

While peak load reduction is a benefit of CES, one of the main reasons for implementation is the increased reliability for customers, as it provides voltage support by adding or absorbing reactive power in the grid and helps to stabilise frequency. In addition, battery storage provides a source of back up energy should there be issues in the system, meaning there is potential to see reduction in power outages for customers as energy stored in the battery is deployed when grid outages occur (Flanegin, 2018).

There a number of different drivers and considerations for the different market participants in the installation of CES, as well as regulatory and legislative considerations. These are presented in Figure 36, red text are potential government influences (Agnew & Dargusch, 2015).

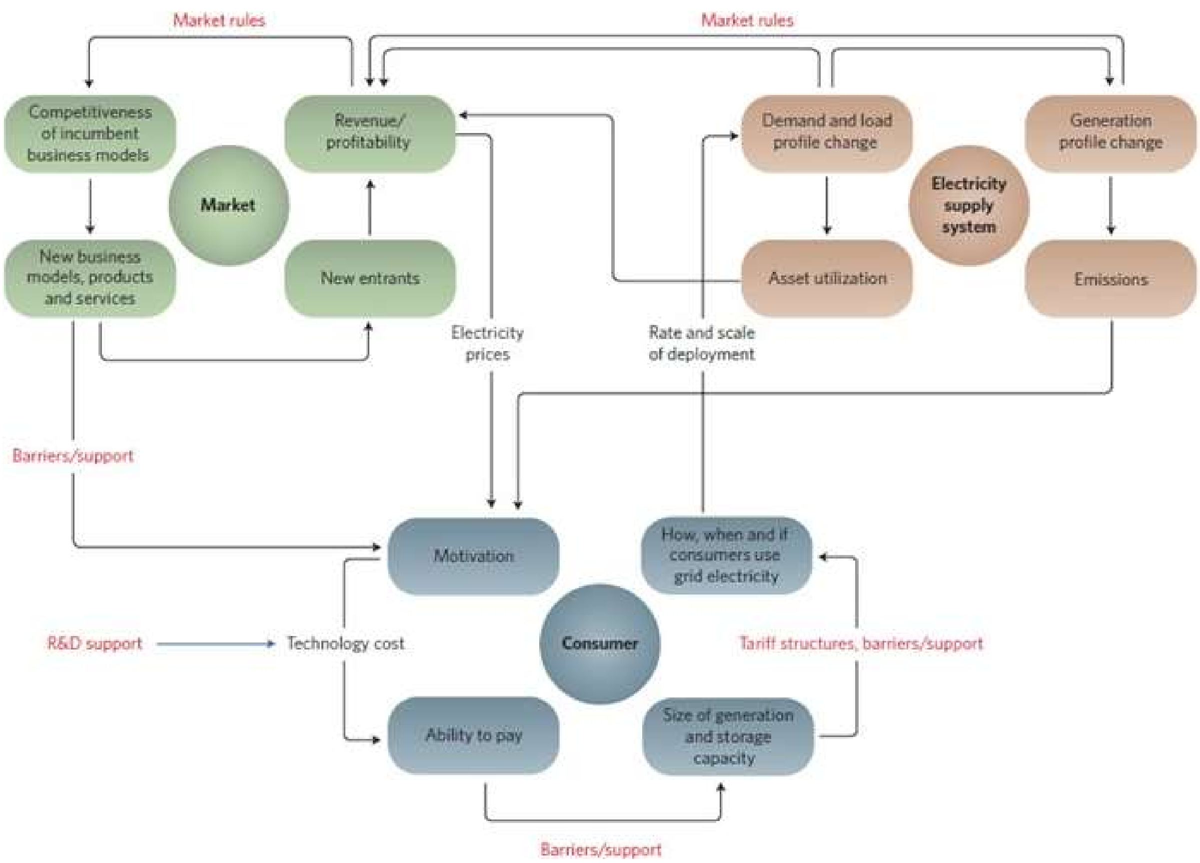

Figure 36 Factors Influencing the rate and scale of solar PV and storage deployment

Utility owned CES systems are a collection of two or more battery storage units connected to the low-level transformers that serve houses or small businesses. These systems are in front of the meter and have the potential to deliver significant value to both utilities, residential and commercial users. A summary of the potential value streams available to each market participant is provided in Table 7 (Flanegin, 2018).

Table 7 Potential value streams for each market participant

Service	Description	Potential Value	Grid	Commercial	Residential
Demand charge reduction	Use stored energy to reduce demand charges on utility bills	H		✔	✔
Energy arbitrage	Buying energy in off-peak hours, consuming during peak hours	H		✔	✔
Demand response	Utility programs that pay customers to lower demand during system peaks	H		✔	✔
Resiliency / Back-up power	Using battery to sustain a critical load during grid outages	H	✔	✔	✔
Frequency regulation	Stabilize frequency on moment-to-moment basis	H	✔	✔	
Capacity markets	Supply spinning, non-spinning reserves	M	✔	✔	
Voltage support	Insert or absorb reactive power to maintain voltage ranges on distribution or transmission system	L	✔		
T&D Upgrade Deferral	Deferring the need for transmission or distribution system upgrades, e.g. via system peak shaving	Site specific	✔		

Utilities will see benefits such as network reliability increases and peak demand reduction, as well as potential deferral of transmission and distribution asset upgrades. Commercial and residential consumer would see benefits through a reduction in the demand charges as they use their own energy instead of energy from the grid during peak times. CES has the potential for arbitrage to further deliver savings to users. In addition, increased resiliency in the distribution network means customers will benefit from fewer outages and reduced power quality issues, such as over-voltage and flicker. Balancing the benefits between utilities and consumers is important in the successful delivery of CES.

Western Power delivers community energy storage to key areas in its network:

Case Study: PowerBank & Western Power

Western Power is partnering with PowerBank to introduce community energy storage solutions at strategic locations in its network, where solar PV penetration levels are at their highest, for example, in Busselton, WA. Customers are allocated virtual storage in the battery, and as their solar panels generate solar power during the day, up to 8kwh of excess or unused power is automatically transferred to the battery. From 3pm to midnight, households can draw energy back from the battery to power up their homes, covering the energy-use peak hours between 3pm and 9pm. At midnight, any excess power still in the battery is returned to the grid, with the householder paid the standard feed-in tariff.

Western Power estimates that the solution is 30% cheaper than installing a battery for an individual residence. Additional savings are expected as residents can use their own power during times of peak demand.

The case study suggests that integrating batteries into local communities improves Western Power's ability to balance neighbourhood load profiles during the day and allows more homes to install solar panels (Energy, 2020).

Several factors that need to be considered for the implementation of CES to achieve optimal outcomes for the different market participants:

- *Site and size selection* - Deployment of community energy storage requires a complete allocation framework that will optimally size, site and dispatch storage units by considering both technical and economic benefits (Sardi, 2017).

  CES will be designed to provide the energy needed by the community during the period where there is no sunlight. This minimum requirement would require the electricity distributor to be able to supply electricity as a backup for extended periods of low sunlight, to manage the risk that there may not be enough generation from local rooftop solar to satisfy demand. Consumers will therefore be contributing to network fixed costs as they do now and also to the cost of their CES, this increase in fixed charges offset by a reduction in energy demand from external generators.

  It is possible to have a CES solution that enables the distributor to go off-grid, thereby removing a significant part of its network and enabling a reduction in fixed network charges. For this to happen, CES would need to be sized to ensure supply during extended periods of low solar irradiation (long periods of thick cloud cover, for example), or a local diversified energy supply (a local wind farm, bioenergy generation) added to the city grid for risk reduction purposes.

- *The changing roles and responsibilities of market participants*
  - With increased usage of rooftop solar and the introduction of CES, many customers are transitioning from consumers to prosumers/prosumagers, i.e. producers, consumers and storers.
  - Further, while most CES at present is utility owned and managed, local communities may have roles in ownership and governance of local systems, as well as local energy markets in the form of peer-to-peer sharing. These can be associated with microgrids which decrease reliance on grid power.
  - However, local communities often lack the technical skills for operation and maintenance of energy storage systems, providing roles for energy service companies or technology service providers.
- *Evolving requirements from the network and associated infrastructure* - Because of the changing roles and responsibilities catalysed by CES, consideration must be given to the evolving requirements to infrastructure and regulatory requirements, such as:
  - Platforms for local level energy markets for allocation and trading
  - Changes to energy policy, legislation and tariff structures
  - CES needs bidirectional energy and information flows as well as interactions among its several actors. In the centralised energy system with unidirectional flows this can be complicated.
  - Governance and business models that allow collaboration between social and energy system actors.
- *Business Models and Regulatory Barriers*

  As mentioned in earlier sections, CES could be fully community owned or may be developed in partnership with public and private sectors. The delivery and ownership structure of CES will influence the level of regulatory barriers present. For example, CES systems adopted in community-owned microgrids have less barriers to achieving cost effective storage and use, while significant regulatory barriers exist, making sharing through a public grid economically unattractive (Muller & Welpe, 2018). Muller and Welpe found that removing these policy barriers would enable more efficient use of energy storage systems.

  The local community owning CES will not usually be able to operate and maintain the system itself, and the incumbent distributor may be reluctant to lease or sell its local network to local communities. In Australia, the majority of CES systems are utility operated and maintained. This seems the most prudent arrangement and seems likely to continue. There is no reason, in principle, why the CES needs to be owned by the distributor.

Case Study: Strombank

Strombank conducted a 15-month field test with 18 participating PV owners. The model was similar to a conventional bank: Participants obtained a specific share of the storage capacity of the 100 kW battery and could deposit and withdraw electricity within their share.

The project led to a considerable increase in self-sufficiency. Moreover, participants had the possibility to trade excessive electricity in the community. The managing of their share was done over an app. The project resulted in a 75% reduction of feed in of excess solar, a reduction of grid electricity by 40% with self-supply averaging around 60-80% (Tuerk, Neumann, Frieden, & Peeters, 2019).

Increasing penetrations of DER increase the need for energy storage in the distribution system, but there are some key challenges for implementation of CES:

- Policy, legislation, the regulatory environment and current tariff structures are not conducive to CES (CES cannot currently be installed by grid owners, for example).
- Capital costs are significant, and CES may not be economically feasible with current tariff structures.
- It may be difficult to align the expectations and roles of users and market aggregators and to allocate the benefits effectively.
- CES needs bidirectional energy and information flows as well as interactions between several actors. This can be complex in a centralised energy system with unidirectional flows.
- Local energy markets will be needed for allocation and trading.
- Governance and business models will be needed to allow collaboration between social and energy system actors, determining, for example, which organisation is best able to deliver infrastructure and undertake maintenance on the CES and associated networks, and how are services levels (such as response time) will be determined.

5.4 Large-scale energy storage

There are numerous types of large-scale storage technologies deployed, the most common of these being lithium-ion batteries. A summary of recent long-term battery storage projects in Australia using lithium-ion batteries is presented in Table 8.

Table 8 ARENA-funded battery storage projects

Project	Capacity	Storage	Description	Project Cost
Energy Storage for Commercial Renewable Integration (ESCRI-SA)	30 MW	8 MWh	A large-scale grid-connected battery at Dalrymple substation, Yorke Peninsula, South Australia (ARENA, 2020).	$30m
Gannawarra Energy Storage System (GESS)	25 MW	50 MWh	A battery co-located with the Gannawarra Solar Farm in north western Victoria (ARENA, 2020).	$41m
Ballarat Energy Storage System	30 MW	30 MWh	A large-scale, grid-connected battery located at the Ballarat electricity station (Ballarat Area Terminal Station (BATS) (ARENA, 2020).	$43m
Lake Bonney	25 MW	52 MWh	A battery energy storage system co-located with the 278.5MW Lake Bonney wind farm in South Australia (ARENA, 2020).	$42m

The review of these projects has identified a series of areas for future technical development (Aurecon, 2019):

Area	Description
Proven capabilities of battery storage	
Wholesale energy market participation / arbitrage	Participation in the wholesale energy market based on market prices. Curtailment management to support renewable generation.
Contingency Frequency Control Ancillary Services and Fast Frequency Response	Autonomous dispatch of power based on an approved frequency droop curve and deviations in power system frequency from the normal operating band. There is standard capability to provide Fast Frequency Response using battery systems (much faster than the maximum six second response time required by the market).
Regulation Frequency Control Ancillary Services	Battery storage systems can adjust power output more rapidly and precisely than open cycle gas turbine units in response to AEMO's Automatic Generation Control (AGC) regulation FCAS signals.
Network loading control	Battery storage could be located in a certain part of the network to enable transmission elements to be operated within their continuous rated limits.
Fringe of grid islanding	Battery systems configured for grid forming and micro-grid operation to address reliability issues at fringe of grid locations (such as lack of redundancy or long response times).
Voltage control	Reactive power capacity to support voltage control. Voltage Control Ancillary Services (VCAS) can provide reactive power to maintain voltage and stability within required limits following a credible contingency event.
Areas for future technical development	
Simulated/synthetic inertia	Grid forming batteries have the potential to provide simulated inertia (reduce the Rate of Change of Frequency during contingency events, to enable contingency Frequency Control Ancillary Services (FCAS) service sufficient time to operate).
System strength	Improved knowledge of the capability of different battery inverters to provide system strength support.
Power system modelling	Demonstration of the capability of battery inverters to support increasing Variable Renewable Energy (VRE) penetration.
Bidding algorithms	Development of bidding tools to maximise revenue streams.
Flexible warranties	Further development of battery degradation warranty structures.
Degradation management	Development of strategies to extend battery life beyond the nominal 10-year life expectancy.
Decentralisation and islanding	Improved understanding of how battery storage can support increasing levels of islanding and embedded microgrids.

The capital and operating cost of a 4-hour battery is currently more than twice that of an open cycle gas turbine unit (the current cheapest provider of daily peak capacity). However, AEMO estimates that a 4-hour battery storage may become more economical (have lower capital and operating costs) than continuing to operate an existing open cycle gas turbine unit by 2030 (AEMO, 2020).

There are several emerging battery technologies which may reduce the cost of grid scale storage. For instance, sodium-ion batteries use sodium ions as charge carriers and avoid reliance on lithium (a scarce resource) (Hwang, Myung, & Sun, 2017). Room-temperature Sodium sulphur batteries and salt-water batteries have similar potential for grid scale storage in the future (Xu, et al., 2018).

Alternatives to batteries include hydrogen, molten salt thermal energy storage and pumped hydro energy storage.

Hydrogen

Hydrogen storage involves storing hydrogen created through electrolysis, and later converting it back into electricity. Hydrogen can be converted into electricity by powering a combustion turbine or (more commonly) via a fuel cell. This process is often referred to as a Hydrogen Energy Storage System (HESS) or a Regenerative Hydrogen Fuel Cell (RHFC).

Key advantages of hydrogen storage are that the only by-product is water, and that hydrogen can be stored for longer time periods (in excess of weeks) than a battery can hold charge, meaning that hydrogen can be used for 'seasonal' storage. However, grid-scale hydrogen storage via fuel cells has a relatively low round trip efficiency (of around 30-40%) compared to other commercially viable technologies (such as utility scale battery storage, which has an efficiency of around 85-95%) (Pellow, Emmott, Barnhart, & Benson, 8 April 2015). This technology requires significant advancements, as well as favourable economic and regulatory conditions to be commercially viable.

Case Study: Kahua Ranch Hydrogen Demonstration

The demonstration tested an integrated hydrogen generation and storage system at Hawaii (Lutz, Stewart, Busquet, Ewan, & Rocheleau, 22 January 2010). The system produced hydrogen via electrolysis using power supplied by wind turbines and solar PV (using a 12 kg/day electrolyser). The hydrogen storage system HSS uses a fuel cell to convert hydrogen back to electricity (a 5 kW fuel cell power system).

The high cost and low efficiency were deemed to make such a system difficult to technically or economically justify. However, the hydrogen storage system was capable of storing hydrogen for long periods of time. With significant improvements in technology, hydrogen storage could represent a means to address seasonality issues associated with renewable energy sources.

Molten Salt Thermal Energy Storage

There are a range of thermal energy storage technologies which enable excess thermal energy to be stored in a media. Molten salt is one technology used for this purpose (typically in concentrating solar power applications) because it is able to store energy at high temperatures. It involves heating and storing molten salt in insulated storage tanks. When energy is required, the hot molten salt can be used to produce superheated steam for a conventional steam-generator, allowing for balancing of energy demand between day and night (or possibly over longer periods).

Case Study: Solana Generating Station

Solana is a 250-MW parabolic trough concentrating solar power plant which uses a thermal energy storage system with molten salt as the energy storage media (U.S. Department of Energy, n.d.).

The storage system provides 1000 MWh of energy that is dispatchable on demand, that allows electricity production for up to six hours without sunlight (using a steam generator). The Solana solar power plant provides clean energy to 70,000 households, and has the potential to reduce greenhouse gas emissions by 475,000 tonnes per year when compared to energy generated through fossil fuels (PowerTech, 2020).

Pumped Hydro Energy Storage

The pumped hydro energy storage method uses the gravitational potential energy of water to store energy. The method pumps water to a higher storage point when there is excess energy available, and can later be released downhill (through a turbine) to produce electricity. This results in less variable power supply from renewable energy sources (where are dependent on weather conditions).

Storage capacity can be significant and is determined by the size of the reservoirs. This approach can also be relatively efficient, with round-trip efficiencies of up to 80% (Energy Storage Association, 2014).

Case Study: New South Wales

Hydro energy storage is a significant feature of the New Sales Wales energy network. The Snowy Hydro-electric Scheme was commissioned in 1974 and is the largest Hydro Energy Storage system in Australia, with a total generating capacity of 4,100 megawatts (MW) (Snowy Hydro, 2020).

There are currently 36 hydro-electric power stations in NSW, and plans for further expansion are identified as part of NSW Water's pumped hydro roadmap to address power security needs as power plants are retired in the future (Water NSW, 2018).

5.5 District heating

Demand for energy, and particularly gas, peaks during the winter months in the ACT (Figure 37), when both gas and electricity are used to run space and water heating in residential and commercial buildings. The economies of scale and generation efficiencies that can be achieved with district heating means that its implementation has the potential to reduce peak demand during this period (ACT, 2015).

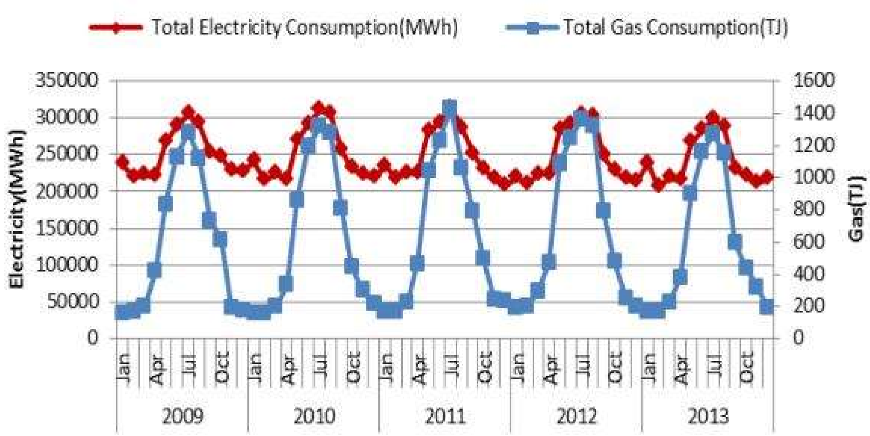

Figure 2. Monthly aggregate consumption (1 Jan 2013 -31 Dec 2013)

Figure 37 Historical Energy Consumption – Gas and Electricity

District heating is heat generated at a central location to be distributed to residences and commercial buildings to meet heat demand. These systems are often more efficient than a decentralised heating solution, and research has shown that with district heating or a combined heat and power system (CHP), there is potential to reduce peak demand. Further, district heating based on CHP can have a positive impact on greenhouse gas emissions when compared to electricity based heating solutions ((Gustaffson, Myhren, & Dotzauer, 2018).

Globally, most of the energy required to deliver district heating solutions is provided by fossil fuels (Figure 38), but in countries like Denmark, Sweden and Switzerland where district heating meets up to 50% of heating demand, renewable energy can account for up 40% of heat supply (IRENA, 2017). Stockholm, Sweden has been using a district heating system for decades that relies on mostly renewable sources such as waste, wood chips, and bio pellets. Research has demonstrated that CHP and heat pumps can help balance renewable energy production in this district heating system (Levihn, 2017).

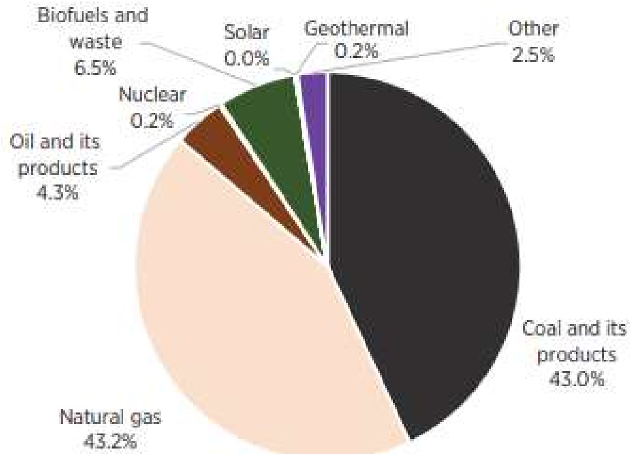

Figure 38 District Heating energy use globally

If not already in place, distribution infrastructure can add significant capital costs on top of generation costs. This makes it more desirable for new buildings and developments.

5.6 Impacts on electricity supply

An uptake in hydrogen-powered vehicles will need to be accompanied by an increase in hydrogen production (this is discussed further in Section 6.1). Generally, this will increase overall demand for electricity and may prompt greater renewable generation (the impacts of distributed energy sources on the network is discussed in Section 5.3).

The distribution network will be impacted by small-scale production facilities that use less than 10MW of energy to produce less than 162kg of hydrogen per hour. Larger facilities may connect to the transmission network directly to draw the power required for hydrogen production, whereas small-scale facilities could use dedicated HV feeders from existing substations.

Table 9 provides a summary of the electricity and water requirements to produce the hydrogen required to fuel hydrogen vehicles under a theoretical scenario (of 50% market penetration in the ACT).

Table 9 Resourcing hydrogen for vehicle use

Consideration	Assumption
Hydrogen required by vehicles	1kg of hydrogen is required per 100km travelled[12] (COAG Energy Council, 2019).
Average distance travelled per car	The average car in the ACT travels around 12,700 km per year (ABS, 2019).
Number of cars in the ACT	The ACT currently has about 340,000 registered vehicles (ACT Government, 2019). *Applied assumption: 50% market penetration and no growth in total vehicle numbers (170,000 hydrogen vehicles).*

[12] Hydrogen requirement based on Hyundai Nexo and may vary for different sized vehicles.

Consideration	Assumption
Hydrogen required per year to fuel hydrogen cars (total, kg)	Around 21,590 tonnes of hydrogen would be required to fuel 170,000 vehicles (travelling a total distance of 2.2 billion km).
Power required to generate 1kg of hydrogen	A 100% efficient electrolyser requires 39 kWh of electricity to produce 1 kg of hydrogen (Gardner, 2009). Hydrogen production (via electrolysis) typically runs at 60-80% efficiency (Kumar & Himabindu, 2019). *Applied assumption: 50 kWh of electricity to produce 1 kg of hydrogen.*
Water required to generate 1kg of hydrogen	9 litres of purified water (minimum) are required to produce 1kg of hydrogen (COAG Energy Council, 2019).
Electricity required to produce hydrogen for vehicles for 1 year	**1,080 GWh of electricity** would be required to generate the hydrogen to fuel 170,000 vehicles.
Water required to produce hydrogen for vehicles for 1 year	**194 ML of water** would be required to generate the hydrogen to fuel 170,000 vehicles.

If 50% of the ACT's fleet were replaced by hydrogen-powered vehicles, electrical energy supply to the ACT would need to be increased by about 36% (based on current consumption of 2,986 GWh per year, as detailed at Section 4.0). Rooftop solar with storage is unlikely to be sufficient to provide this, noting that the maximum possible generation capacity with 100% solar penetration would be less than 500MW (Section 4.0), and that this level of penetration would have significant impacts on the network.

Electric vehicles are more efficient and would need about half to a third of the energy required by hydrogen vehicles (Section 5.2). If 50% of the ACT's fleet were replaced by electric vehicles, energy supply in the ACT would need to be increased by about 12-18%. As discussed at Section 5.1, this increase may be able to be offset by solar energy and storage (if 2kW of solar panels are installed for each electric vehicle[13]).

5.7 Key findings

Key findings include:

- Some of the issues presented by increasing penetration of solar PV and DER can be addressed through the integration of energy storage into the distribution network, which can help provide system reliability, reduce energy loss, and reduce peak demand.
- The uptake of electric vehicles could enable V2H solutions to reduce peak demand, provided options are available to manage battery life. High penetration of electric vehicles could provide enough short-term storage to substitute for gas through most of the year.
- The increasing integration of distributed energy resources into the electricity distribution network has the potential to impact the system through system losses, peak load impacts, transformer age impacts, voltage regulator mechanical wear, and power quality issues.
- Despite reducing overall demand, a higher prevalence of rooftop solar PV (without storage) does little to reduce peak demand. It can create a 'peakier' demand profile as users become net exporters during times of low demand, but since the grid must have the capacity to satisfy peak demand, this will not reduce overall costs and is likely to increase the unit cost of energy served.

  Depending on its location, community energy storage (CES) has the potential to deliver benefits to utilities through reduced peak demand, improved system reliability and deferred or avoided network upgrades.

[13] This figure reflects the additional load corresponding with electric vehicles only (does not reflect household usage).

CES can reduce costs for consumers through mechanisms such as energy arbitrage and demand smoothing, and reduce the additional fixed charges required to recover the additional investment needed in the grid to ensure that peak demand is met.

- Studies suggest that 2kW of rooftop solar generation could enable charging of one EV. If a typical household could be 95% self sufficient with a 7kW solar system and a 35 kWh battery storage pack, then 9kW of solar generation plus storage and a similarly upscaled storage pack could potentially make the household self-sufficient for both home and transport energy needs (using an EV), assuming that the clear roof space is available.

  Incentives to adopt a strategy such as this could potentially encourage more economic investment than the enhancements of the electricity distribution system that would otherwise be needed.

  Further study is required to confirm viability and determine the optimum configuration for households in the ACT to enable them to remain self-sufficient through the year (noting that EVs themselves would need to be at least cost competitive with internal combustion engines for this approach to be attractive).

- District Heating has the potential to reduce peak demand in winter months but may require significant investment in distribution infrastructure.
- The magnitude of these impacts will depend on location, size and allocation frameworks, as well as changes to regulatory barriers and tariff structures.

6.0 Strategies to reduce energy emission - Gas Distribution Network

In 2018-19 the ACT emitted 6.07 tonnes of CO2-e per person, 18% less than the previous year. 42% of those emissions were due to transport, 31% to electricity and 14% to natural gas (Utilities Technical Regulation Annual Compliance Report 2018-19).

As of 2019-20, the ACT's electricity supply will be 100% renewable, and the largest remaining sources of emissions will be transport (estimated at over 60%) and natural gas (over 20%) (ACT Government, 2019).

The ACT natural gas distribution system network, owned by Evoenergy Gas and operated by Jemena, consists of approximately 4,000km of pipeline and delivers approximately 7.5 PJ per year (2,000 GWh).

This section reviews the impact on the gas distribution system of options available to the ACT Government to reduce emissions from the use of natural gas, such as the substitution of hydrogen or biomethane for natural gas, and termination of the gas supply. We have sourced papers and research on these topics and summarised them in this section. We have also included case studies as further illustration of these impacts.

6.1 Substitution of natural gas with hydrogen

Hydrogen can be produced from clean energy sources via an electrolysis process (which splits water into oxygen and hydrogen) with no carbon emissions, so introducing hydrogen into the gas network would reduce emissions. Hydrogen can be blended with natural gas or used an alternative fuel. The Commonwealth has noted ambition to ‘enabling blending of hydrogen with natural gas and eventual use of 100% hydrogen in gas networks’ (COAG Energy Council, 2019).

There are four key applications of hydrogen (Figure 39):

1. Hydrogen injection into gas pipelines;
2. Hydrogen as grid scale storage;
3. Hydrogen export for use in a fuel cell;
4. Hydrogen fuelled vehicles.

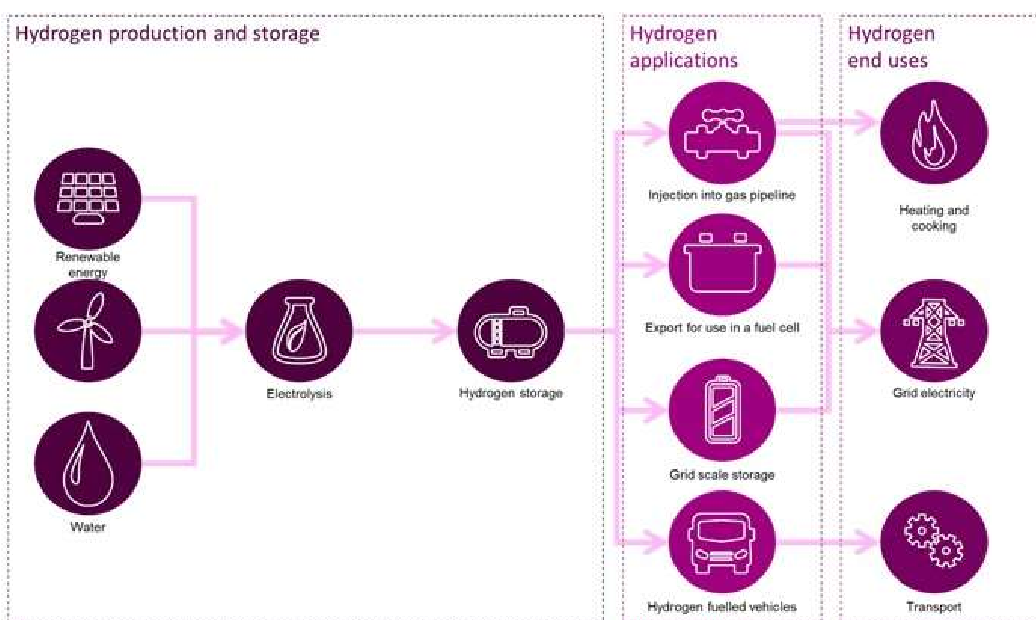

Figure 39 Hydrogen production, storage and applications, Source: AECOM analysis

Several factors determine the suitability of existing gas networks for hydrogen distribution:

Leakage Hydrogen is more permeable than natural gas, so there is a higher rate of leakage through distribution pipes. A study on the U.S. natural gas distribution system found that permeation rates for hydrogen in plastic pipes are about four to five times greater than for methane in typical polymer pipes and occurs mainly through the pipe walls. Permeation rates increased with pressure, but the age of the pipe was found to have no significant effect (Melaina, Antonia, & Penev, 2013).

Leakage through steel and ductile iron gas distribution systems was found to occur mainly though seals and joints (as opposed to the pipe walls), and the volume leakage rate for hydrogen was around three times higher than for natural gas (Melaina, Antonia, & Penev, 2013). The study (which investigated concentrations of hydrogen up to 20%) generally found that leakage is economically insignificant but could pose safety risks.

Safety There is an increased risk (probability and severity) of ignition when natural gas distributions contain higher concentrations of hydrogen. It is difficult to make general claims about safety due to the large number of factors involved (a detailed risk assessment would be required because the risk can vary widely from location to location).

A quantitative risk assessment of the U.S. natural gas supply system found that adding concentrations of 20% hydrogen to natural gas resulted in a minor increase in risk (with overall risk being insignificant). At concentrations greater than 20%, the overall risk in service lines was found to increase significantly (largely due to potential accumulation of hydrogen in confined spaces) but the overall risk was still considered moderate with concentrations of up to 50% (Melaina, Antonia, & Penev, 2013).

Hydrogen is colourless, odourless and tasteless making it impossible for humans to detect. Because of its characteristics, some of the leak detection techniques used for natural gas are not compatible with hydrogen. Semi-conductor-based leak detectors are compatible, but flame ionisation and infrared sensors are not and these would require replacement (Energy Pipelines CRC, 2017).

Material Durability Exposure to hydrogen over long periods of time can lead to accelerated deterioration of some types of ferrous metal pipe (hydrogen embrittlement and cracking due to absorption of the small hydrogen molecules). This impact increases with higher concentrations of hydrogen and at higher pressures (Energy Pipelines CRC, 2017). Hydrogen induced failure is typically not a concern under typical operating conditions for distribution systems with pipes made from other metals (such as ductile iron, cast iron, wrought iron, and copper).

Hydrogen is not noted to impact polyethylene (PE) pipes or polyvinylchloride (PVC) pipes (Energy Pipelines CRC, 2017). Similarly, hydrogen is not noted to impact the nylon pipes in use in the ACT (Barth, R. R.; Simmons, K. L.; San Marchi, C., 2013).

Other Issues Other issues to be noted include:

- *Capacity:* Hydrogen has a lower energy density than natural gas, so larger volumes of gas would need to be delivered with higher rates of blending. This can be thought of as a loss of capacity - for a 10% hydrogen blend, the average loss of capacity is estimated to be 2.4% (COAG Energy Council, 2019).
- *Metering:* The presence of hydrogen can influence the accuracy of existing gas meters. The deviation/accuracy is generally found to be within acceptable limits, but turbine meters require recalibration (Energy Networks Australia, 2017).
- *Storage:* Storage of hydrogen for injection into the network adds a very significant cost. Current industry practice involves storage using high pressure gas tanks or cryogenic storage using metallic hydride tanks (Gotz, et al., 2016).
- *Production:* Hydrogen production (via electrolysis) is a capital-intensive process that typically runs at 60-80% efficiency (Kumar & Himabindu, 2019).

Hydrogen blending into natural gas networks is already occurring or being planned in Australia. One of these projects is H2GO:

Case Study: H2GO, New South Wales

One significant project by Jemena in New South Wales (H2GO) is injecting renewable hydrogen (produced via electrolysis from solar and wind power) into Jemena's existing gas network, which supplies 1.3 million customers. The blend to be delivered is 10% hydrogen **(ARENA, 2018)**. Other studies and investigations in Australia have generally focused on similar hydrogen volumes (up to 10%) **(COAG Energy Council, 2019)**.

While trials of hydrogen blending in Australia have generally focused on injection of hydrogen at relatively low volumes (up to 10%), there has been one significant study (H21 Leeds City Gate) in the United Kingdom on the feasibility of transitioning to a 100% pure hydrogen network:

Case Study: H21 Leeds City Gate, United Kingdom

A major study in Leeds has investigated the technical and economic feasibility of transitioning to a 100% pure hydrogen network **(H21, 2019)**. The study concluded that there is adequate capacity in the network to facilitate such a transition, and that much of the existing low pressure distribution could be used (polyethylene pipes). However, high-pressure iron pipes would need to be replaced with a new network. The project identified a staged transition, which involved isolating small zones of the network and converting to hydrogen during low demand periods.

Performance of consumer appliances is affected at relatively low hydrogen volumes, and acceptable concentrations of hydrogen for appliances designed for natural gas generally falls within the 5%–15% range (Energy Pipelines CRC, 2017). Higher concentrations of hydrogen may necessitate modification or replacement of residential appliances, but some industrial scale appliances could be modified to suit higher hydrogen blends:

Case Study: HyDeploy, United Kingdom

There is a live pilot study in the UK (HyDeploy), where hydrogen is being injected into the natural gas supply to a small network of homes, to investigate whether blends of up to 20% hydrogen can be reached without modification to consumer appliances. Levels of 15% hydrogen have been achieved at the time of writing this report (HyDeploy, 2020).

There is potential demand for hydrogen refuelling stations as fuel cell electric vehicles are introduced. Current studies and projects rely on hydrogen delivered and stored at refuelling stations via truck or pipeline or produced on site. There is potential to use the natural gas distribution system to deliver hydrogen via blending, with separation and purification carried out at the point of use using gas separation technologies (such as pressure swing adsorption) (Melaina, Antonia, & Penev, 2013).

For the medium-term future, it seems likely that truck delivery would likely the most economic and / or feasible option. A study by (Yang & Ogden, 2007) compared the cost of delivery options (compressed gas truck delivery, liquid truck delivery or pipeline) and found that the lowest cost delivery option in markets with small stations and low demand was compressed gas truck delivery, and in markets with long distances and moderate demand the lowest cost delivery option was liquid truck delivery.

It appears most feasible in the medium-term future that hydrogen be generated in large scale facilities (i.e. at solar or wind farms) and distributed to refuelling stations. Advances in technology may however make it economical to produce and store hydrogen on-site (Evangelopoulou, De Vita, Zazias, & Capros, 2019).

Case Study: H2 MOBILITY, Germany

There are already a significant number of hydrogen refuelling stations in operation at Germany (84 at the time of writing this report, with the goal of completing 100 by the end of 2020 **(H2 MOBILITY, 2020).** The project aims to where possible integrate the new hydrogen stations with existing filling stations. Hydrogen is typically delivered to these stations via tankers as compressed gas.

Hydrogen is currently produced via renewable sources at 11 facilities. One such facility is 'EnergieparkBL' which produces hydrogen via electrolysis using excess power produced at adjacent wind farms. This hydrogen is then delivered to hydrogen refuelling stations via tankers **(NOW GmbH, 2020)**.

Germany's National hydrogen Strategy targets to increase green hydrogen production capacity to 5 GW by 2030 and 10 GW by 2040 (via large-scale offshore and onshore energy generation facilities) **(BMWi, 2020)**.

In industries where electrification may be challenging there is potential for growth in demand for hydrogen:

Steel There is potential use of hydrogen in the production of steel. Pilot facilities in Germany (Mazengarb, 2019) and Sweden (HYBRIT, n.d.) use hydrogen as a reducing agent (instead of coking coal) to remove oxygen from iron ore in the production of steel.

Cement There is potential application of hydrogen to fuel cement kilns (Pee, et al., 2018).

Shipping There is potential growth in demand for hydrogen as a fuel for long distance shipping (Bannon, 2018).

Aviation There is potential growth in demand for hydrogen in the aviation sector (Baroutaji, Wilberforce, Ramadan, & Olabi, 2019).

6.2 Substitution of natural gas with biomethane

Introducing renewable natural gas (biomethane) into the gas network would reduce emissions. Biomethane is commonly produced by cleaning biogas, a common by-product of wastewater treatment that is otherwise discharged into the atmosphere or disposed of through burning, or of anaerobic digestion of organic matter.

Biomethane is very similar in composition to natural gas, and can be distributed through existing natural gas networks without significant modification of the distribution system or the end-use appliances (ENEA Consulting, 2019). Use of biomethane as a substitute means that it is not released into the atmosphere, and that the volume of natural gas required can be reduced, avoiding that proportion of the emissions due to natural gas.

The supply of organic material to produce biogas is, unfortunately, very limited (with urban waste being the primary feedstock in the ACT). Deloitte suggested that the potential for biogas production in the ACT is only a maximum of 3% of regional gas consumption (Deloitte, 2017). It has been estimated that with full utilisation of feedstocks, biogas or biomethane could supply around 20% of gas demand globally (but current utilisation is a fraction of this) (International Energy Agency, 2020). The cost of production of biogas can also be significant, especially where there is the requirement to transport feedstock. The feedstock typically has a low mass density, so production of biogas may not be viable where the feedstock must be transported more than 50 kilometres or so.

Methane is already captured from the Mugga Lane landfill in Canberra, but is used to generate electricity (as opposed to being used as a substitute for natural gas).

Case Study: Mugga Lane Landfill Gas Upgrade Project, Canberra

A four megawatt landfill gas-to-energy system has been constructed in Canberra's Mugga Lane landfill. The system will capture up to 70% of the methane produced at the landfill (otherwise emitted into the atmosphere), to fuel four generators and supply electricity to around 5,700 Canberra households **(Brown, 2020)**.

6.3 Termination of natural gas distribution

The maximum blending rate for hydrogen of 15% (without changes to existing infrastructure and appliances) and the physical and economic challenges of replacing natural gas with hydrogen imply that a target of zero emissions cannot be achieved using hydrogen. While biomethane would be a viable alternative, in practice the limited volumes available means that zero emissions cannot be achieved solely by using biomethane either.

Given these constraints, the likely remaining option to achieve zero emissions is the eventual termination of natural gas use and replacement of the energy served through the gas distribution network with renewable electricity. This option has several implications:

- Termination before the end of service life of the assets would result in stranded assets, forcing impairment and write-down unless an alternative use can be found for the existing infrastructure. Termination would therefore be timed to coincide with end of service life, so that the assets are fully depreciated.
- Cost will be incurred in the decommissioning of pipelines (for activities such as in-situ abandonment with purging, isolation and filling, or potential excavation).
- Terminating the gas supply would significantly increase demand on the electrical network, especially during peak times (may result in demand across the NEM being around 21,000 MW higher in 2050 (Deloitte, 2017)). Significant expenditure on the electrical network would be required to cater for this (potentially more than $30 billion across the entire NEM (Deloitte, 2017)).
- The transition from gas to electricity would likely be a gradual process.

Key considerations surrounding the termination of natural gas supply include:

Impairment Gas distribution pipelines (and associated assets) could become redundant before being fully depreciated, forcing an impairment or write-down in value. Pipelines typically have long life expectancies (i.e. over 50 years), so the asset write-down could be significant. This is especially significant for the ACT, given the relatively young gas network, with reticulated gas supply first established in the ACT in 1982 (Evoenergy, 2020).

De-commissioning costs

Decommissioning activities required may include (ATCO Gas, 2018):

- In-situ abandonment with; purging of flammable/hazardous contents, isolation (cutting and capping), filling (with concrete or bentonite, for example).
- Potential excavation (removal) and backfilling.

Decommissioning requirements may vary on a case-by-case basis.

Case Study: APA Perth Gas Lateral, Peth

In 2017 APA published an environmental management plan for the decommissioning and abandonment of the Perth Gas Lateral pipeline (a 14.3km transmission pipeline in the Perth metropolitan area) **(APA, 2017)**. Activities included:

- Purging natural gas from the pipeline with air;
- Isolating the pipeline, by cutting / removing length of pipe, installing end caps, coating and testing;
- Pigging (cleaning) the pipeline;
- Abandoning 10.5 km of empty (filled with air) pipeline in-situ for use as a service conduit for rail infrastructure;
- Grouting (filling) 3.7 km of pipeline for in-situ abandonment;
- Removal of some short sections of pipeline.

Impact on the Electricity Network

Shifting the energy requirement currently served by natural gas to the electrical network would significantly increase the demand placed on the network, particularly during peak times. Substantial investment would be required to improve electrical network capacity to substitute for this (electricity generation capacity and transmission capacity).

As discussed at Section 4.0, natural gas provided 57% of ACT's energy during the winter energy demand peak. This indicates that electricity supply would need to be increased by around 40-60% (Section 4.0) to ensure functionality during the winter peak.

Deloitte estimated that peak demand across the NEM would be around 21,000 MW higher in 2050 if the gas network was terminated across the NEM, and would require investment of more than $30 billion ($1.5million/MW) (Deloitte, 2017).

Extrapolating from these figures (noting that ACT comprised a 3% share of national gas demand in Deloitte's figures), the peak demand in the ACT network could be around 630 MW higher by 2050, and the associated cost to augment electrical networks could be of the magnitude of $1 billion (ignoring other options such as renewable energy production and storage).

Managing Distribution During the Transition

There are limited precedents for termination of entire gas distribution networks, but there are examples of significant network transitions (such as the transition from town gas to natural gas some 50 years ago).

It is expected that termination of natural gas would be a gradual process, similar in logic to the approach proposed for the H21 project in Leeds of isolating small sections of the network for transition during low demand periods (H21, 2019). Given its application for heating, gas flow is generally highest in winter, with a morning and evening peak. In severe weather situations (e.g. unusually cold days) gas and electricity demand could peak together (Environment, Planning and Sustainable Development Directorate, 2015).

The total demand for energy needs to be considered, given that termination of the gas supply will place additional load on the electricity network.

Community Energy Storage (CES) of rooftop solar energy has the potential to reduce peak demand in the electricity network (Section 5.3) Integrating CES into the electricity distribution network could potentially offset part or all of the increase in electricity demand resulting from the termination of the gas supply. Investment in CES can therefore be considered an alternative to investment in network upgrades (upstream of the CES), but these transitions would need to be coordinated. It is noted that network capacity may still need to be increased downstream of the CES, which would see the full demand increase.

The industrial sector in the Canberra region is relatively small and Evoenergy's major gas customers predominantly include tertiary education facilities, developers and government. However, some 75% of Canberra households currently use gas (Evoenergy, 2020). Consumers would of course need to replace their gas appliances with electrical appliances, but early announcement of policies in this area could enable a gradual replacement of consumer appliances as they reach end of life.

6.4 Key findings

Key findings include:

- There is potential to reduce carbon emissions via the injection of hydrogen or biomethane into gas distribution networks. It appears, however, that it will not be possible to reach zero emissions this way because of technical constraints (hydrogen) and supply constraints (biomethane).

  Given these constraints, it is likely that the natural gas supply will need to be eventually terminated in order to achieve zero emissions.

- It appears unlikely that a rollout of hydrogen-powered vehicle refuelling stations would be enabled via a re-purposed or a new pipeline distribution system. There doesn't appear to be a viable alternative use for the gas distribution system.
- If there is no viable use for the current gas distribution system after termination, the network will most likely have to be made safe and sealed, but largely left in place because of the high cost of removing assets from under buildings and other structures.
- There is likely to be an impairment charge for the natural gas network.

7.0 Summary of Findings

Summary of findings from this study are presented by topic:

State of Electricity Distribution Network Asset	• The ACT's electrical distribution infrastructure is generally in a satisfactory condition. • Evoenergy is one of the better performing electricity distributors in Australia. It has documented policies and procedures in asset class plans for manage its asset base and will continue to be regulated. Given its past performance it appears likely that Evoenergy will keep its assets in the satisfactory state of repair that they are in now in and should continue the performance it seems to have consistently achieved over the past 14 years.
State of Gas Distribution Network Asset	• The gas network is relatively young and is in a good (overall) condition range. • The gas distribution network is characterised by high value assets with long useful lives (which are accordingly depreciated over a long time period). Assuming that there is no further investment in the network, the residual value of the regulated asset base of the gas distribution system is likely to be approximately $88 million in 2045 (in current dollar terms).
Supply Capacity	• Evoenergy has planned substation enhancements to ensure that it is able to satisfy future demand. Using assumptions of population growth and demand per household, the forecast load on the network is around 68-69% of installed capacity by 2041. Noting that Evoenergy cannot operate at 100% of installed capacity (will need to account for credible contingency events), there is limited spare capacity available. The ACT's supply capacity is closely related to demand projections, and Evoenergy would be expected to continue to retain a prudent reserve. It could therefore be concluded that supply capacity will remain suitable based on current projections. • If electricity were to substitute for the use of natural gas, however, total electricity demand would increase by at least 40-60% unless peak demand can be managed. Evoenergy's current plans do not provide for this scale of increase. • Feeders and other elements of the distribution network will need to be enhanced to cater for a 40-60% increase in load.

Strategies to reduce energy emission - Electricity Distribution Network	• The increasing integration of distributed energy resources (DER) into the electricity distribution network has the potential to impact the system through system losses, peak load impacts, transformer age impacts, voltage regulator mechanical wear, and power quality issues. • Despite reducing overall demand, higher prevalence of rooftop solar PV (without storage) does little to reduce peak demand and can create a 'peakier' demand profile as users become net exporters during times of low demand. • Some of the issues presented by increasing penetration of solar PV and other DER can be addressed through the integration of energy storage into the distribution network, which can help provide system reliability, reduce energy loss, and reduce peak demand. • Community energy storage (CES) has the potential to deliver benefits to utilities through reduced peak demand, improved system reliability and deferred or avoided network upgrades. The introduction of CES in the network should benefit consumers through cost savings. • A transition to electric vehicles may occur after 2024 (estimated to be the time of price parity with fossil fuel vehicles). This will increase overall demand but may also enable reduction of peak demand through V2H solutions. • The magnitude of these impacts will depend on location, size and allocation frameworks, as well as changes to regulatory barriers and tariff structures.
Strategies to reduce energy emission - Gas Distribution Network	• There is potential to reduce carbon emissions via the injection of hydrogen or biomethane into gas distribution networks. It appears, however, that it will not be possible to reach zero emissions this way because of upper limits to blending of hydrogen and the limited supply of biomethane. • Given these constraints, it is likely that the natural gas supply will need to be eventually terminated in order to achieve zero emissions. • It appears unlikely that a rollout of hydrogen-powered vehicle refuelling stations would be enabled via a re-purposed or a new pipeline distribution system. • It may be feasible to encourage a transition to community energy storage and rely on that initiative to limit additional expansion needed in the electricity distribution network that would otherwise be needed to replace natural gas supply. • The impairment cost of the natural gas network in 2045 (or at termination of the natural gas supply) will need to be addressed.

8.0 Areas for Future Investigation

This report has identified several opportunities for future work to inform policy development. Some notable areas include:

- Further investigation into how potential termination of the natural gas supply may be coordinated, noting that;
  - There is opportunity to blend hydrogen or biomethane into the natural gas distribution network to reduce carbon emissions while the network is still in use.
  - The gas distribution system asset data provided by Evoenergy to the AER is aggregated by asset class and does not allow for analysis by service district. The timing of the potential termination of the natural gas supply would be informed (sequenced) by the condition (and remaining life) of the assets by location.
  - Impairment of the natural gas network in 2045 (or at termination of the natural gas supply) will need to be addressed.
  - Further investigation into the strategies for reuse/transfer of ownership and requirements for remediation is required.
- Further investigation into the increase in electrical supply capacity required to substitute the natural gas supply, and quantification of the associated costs.
- Further development of strategies for mitigating the impact of terminating the gas supply on the electrical network. Namely; opportunities for investment in community energy storage as an alternative to investment in upgrades to the electrical network.
- Further investigation into the potential for households to become energy self-sufficient (to a reasonably high level of reliability), the impact of policy designed to incentivise this on the electricity distribution network and the economics of strategy designed to achieve this outcome.
- Further investigation into how policy, the regulatory environment and market structures could enable development and management of community energy resources and / or large-scale energy storage.
- Modelling the impact of the electrification of transport, in the context of facilitating planning for future demand.
- Further investigation into the potential application of DER to offset the impact of an uptake in electric vehicles on the network, and the technical challenges surrounding this.

9.0 Abbreviations

Abbreviation	Description
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGC	Automatic Generation Control
BaaS	Battery as a Service
BSS	Battery Swapping Stations
BNEF	Bloomberg New Energy Finance
CHP	Combined Heat and Power System
CES	Community Energy Storage
COAG	Council of Australian Governments
DER	Distributed Energy Resources
EV	Electric Vehicle
ESCRI	Energy Storage for Commercial Renewable Integration
FCS	Fast Charging Stations
FCAS	Frequency Control Ancillary Services
FCAS	Frequency Control Ancillary Services
GESS	Gannawarra Energy Storage System
GWh	Gigawatt hours
HESS	Hydrogen Energy Storage System
kV	Kilovolt
MVA	Mega Volt Amperes
MW	Megawatt
NEM	National Electricity Market
PJ	Petajoule
PV	Photovoltaic System
PoE	Probability of Exceedance
RHFC	Regenerative Hydrogen Fuel Cell
RAB	Regulatory Asset Base
STPIS	Service Target Performance Incentive Scheme
PV	Solar Photovoltaic
SAIDI	Supply Interruption Duration
SAIFI	Supply Interruption Frequency
VRE	Variable Renewable Energy
V2H	Vehicle to Home
VCAS	Voltage Control Ancillary Services

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Appendix A

Population Data

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Appendix A Population Data

A map of substations and zones is presented in Section 2.0. The mapping of suburbs to zone is shown below, along with the population of all the suburbs.

		Population Projection		
Districts	**Suburb**	**2021**	**2031**	**2041**
Belconnen (includes Belconnen and Latham zone substations)	Aranda	2,449	2,475	2,552
	Belconnen	7,705	9,361	11,988
	Bruce	7,167	6,931	8,755
	Charnwood	3,037	3,309	3,422
	Cook	2,953	3,217	3,287
	CSIRO Ginninderra	7	5,367	7,586
	Dunlop	7,065	6,815	7,006
	Evatt	5,383	5,557	5,704
	Florey	4,850	5,045	5,159
	Flynn	3,352	3,411	3,423
	Fraser	2,004	2,065	2,077
	Giralang	3,344	3,428	3,454
	Hawker	2,971	3,050	3,091
	Higgins	3,306	3,412	3,501
	Holt	5,295	6,225	6,247
	Kaleen	7,549	7,736	7,848
	Latham	3,704	3,885	3,972
	Lawson	1,617	2,974	3,680
	Macgregor	6,925	6,839	6,987
	Macquarie	3,021	3,074	3,065
	McKellar	2,784	2,800	2,817
	Melba	3,186	3,298	3,350
	Page	3,126	3,220	3,269
	Riverview	3,205	13,024	19,488
	Scullin	3,034	3,221	3,261
	Spence	2,599	2,670	2,700
	Weetangera	2,617	2,596	2,608
Belconnen Total		**104,255**	**125,005**	**140,297**
Canberra East (East Lake zone substation)	Canberra Airport	107	126	133
	Hume	468	479	529
	Jerrabomberra	405	364	316
	Majura	81	33	33
	Pialligo	67	29	29
	Symonston	367	330	286
Canberra East Total		**1,495**	**1,361**	**1,326**
Gungahlin (Gold Creek zone substation)	Amaroo	5,868	5,274	5,464
	Bonner	6,835	6,305	5,393
	Casey	6,224	6,887	5,886
	Crace	4,726	4,803	4,026
	Forde	4,239	3,699	3,628
	Franklin	6,852	5,880	5,503
	Gungahlin	8,715	12,653	12,663
	Hall	287	301	313
	Harrison	8,178	6,215	6,404

		Population Projection		
Districts	**Suburb**	**2021**	**2031**	**2041**
	Jacka	830	2,016	1,859
	Kenny	9	2,500	3,000
	Kinleyside	0	0	0
	Mitchell	4	4	4
	Moncrieff	1,984	1,668	1,524
	Ngunnawal	10,752	10,223	10,602
	Nicholls	6,699	6,138	6,272
	Palmerston	5,475	5,189	5,380
	Taylor	1,971	4,274	6,655
	Throsby	2,470	2,615	2,329
Gungahlin Total		**82,118**	**86,644**	**86,905**
North Canberra & City (including City East and Civic zone substations)	Acton	2,179	2,445	2,537
	Ainslie	5,131	5,277	5,367
	Barton	3	3	3
	Black Mountain	0	0	0
	Braddon	5,732	6,132	6,345
	Campbell	6,086	8,292	8,581
	City	7,022	13,891	19,937
	Dickson	2,720	3,869	4,637
	Downer	3,838	4,483	4,510
	Hackett	3,016	3,198	3,283
	Lyneham	5,769	10,152	12,733
	O'Connor	5,597	5,774	5,898
	Parkes	4	1,535	1,582
	Reid	1,686	1,671	1,707
	Russell	3	3	3
	Turner	4,112	4,264	4,488
	Watson	6,539	8,511	8,477
North Canberra & City Total		**59,437**	**79,500**	**90,088**
South Canberra (including Fyshwick and Telopea Park zone substations). Note: Fyshwick is being removed.	Barton	1,355	689	701
	Capital Hill	5	5	5
	Deakin	3,173	3,079	3,130
	Forrest	1,879	2,025	2,025
	Fyshwick	58	58	58
	Griffith	5,255	5,309	5,323
	Kingston	6,121	6,722	10,596
	Narrabundah	6,673	7,072	7,151
	Parkes	5	5	5
	Red Hill	3,361	3,085	3,114
	Yarralumla	3,349	4,160	4,088
South Canberra Total		**31,234**	**32,209**	**36,196**
Tuggeranong (including Gilmore, Theodore and Wanniassa zone substations)	Banks	5,008	4,714	4,833
	Bonython	3,926	3,872	3,935
	Calwell	5,877	5,649	5,749
	Chisholm	5,314	5,229	5,310
	Conder	5,045	4,692	4,786
	Fadden	3,011	2,961	2,996
	Gilmore	2,804	2,664	2,706

		Population Projection		
Districts	**Suburb**	**2021**	**2031**	**2041**
	Gordon	7,749	7,457	7,604
	Gowrie	3,173	3,115	3,179
	Greenway	3,151	5,015	5,941
	Isabella Plains	4,477	4,271	4,347
	Kambah	15,551	15,772	16,006
	Macarthur	1,446	1,353	1,367
	Monash	4,784	3,096	3,130
	Oxley	1,746	1,722	1,748
	Richardson	3,142	3,148	3,221
	Theodore	3,880	3,763	3,844
	Wanniassa	7,857	8,054	8,220
Tuggeranong Total		**87,941**	**86,547**	**88,922**
Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi (Woden zone substation)	Chapman	2,534	2,710	3,027
	Chifley	2,655	2,793	2,864
	Coombs	3,349	4,911	4,988
	Curtin	5,542	5,512	5,631
	Denman Prospect	2,960	9,301	11,673
	Duffy	3,298	3,350	3,440
	Farrer	3,448	3,354	3,433
	Fisher	3,100	3,227	3,305
	Garran	3,590	3,195	3,246
	Holder	2,717	2,817	2,876
	Hughes	3,124	2,998	3,055
	Huntly	38	38	38
	Isaacs	2,509	2,539	2,574
	Lyons	3,425	4,015	4,015
	Mawson	4,165	6,337	7,257
	Molonglo	2,822	18,634	37,928
	O'Malley	1,052	942	956
	Pearce	2,728	2,711	2,753
	Phillip	6,657	12,843	16,222
	Rivett	3,341	3,534	3,626
	Stirling	2,140	2,105	2,147
	Torrens	2,297	2,302	2,328
	Waramanga	2,773	2,877	2,953
	Weston	3,819	4,318	4,345
	Wright	3,453	3,848	4,059
Woden Valley, Weston Creek, Molonglo & Urriarra - Namadgi Total		**77,536**	**111,211**	**138,739**
Grand Total		**444,016**	**522,477**	**582,473**

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Appendix B

Planned Upgrades to Electrical Network

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Appendix B Planned Upgrades to Electrical Network

Evoenergy has identified specific locations where the network is constrained (or limited) or where network limitations are likely to emerge in the short term (and the related works identified) are identified in Table 10 (Evoenergy, 2019):

Table 10 Key Network Limitations

Location	Element	Limitation	Project	Planned Completion	Cost Estimate
Canberra CBD Central	Feeder	Capacity	Construct new 11 kV cable feeder from Civic Zone Substation to London Circuit	2020	$1.3m
Gungahlin Town Centre	Feeder	Capacity	Construct new 11 kV cable feeder from Gold Creek Zone Substation	2020	$3.5m
Dickson - Dooring St	Feeder	Capacity	Extend Haig feeder to Dickson area / Construct new 11 kV cable feeder from Civic Zone Substation to Dooring St, Dickson	2021	$3.5m
Molonglo Valle	Zone Substation stage & Feeders	Capacity	Construct new Molonglo Zone Substation in three stages and construct new 11kV feeders to Molonglo valley developments	2021	$31.2m
Strathnairn	Feeder	Capacity	Extension of the existing O'Loghlen feeder from Latham Zone Substation to Strathnairn (until a new Strathnairn Zone Substation is constructed)	2022	$2.2m
Belconnen Town Centre	Feeder	Capacity	Construct a new 11 kV cable feeders from Belconnen Zone Substation to Belconnen Town Centre	2022	$1.8m
Canberra CBD East	Feeder	Capacity	Construct new 11 kV cable feeder from City East Zone Substation to Donaldson St, Canberra City	2023	$2.3m
Fyshwick	Zone Substation	Condition	Decommissioning of Fyshwick zone substation 66 kV assets	2024	$5.6m
North Canberra	Transmission	Voltage	New Substation at Stockdill Drive, West Belconnen and 132 kV line connection	2024	TBC
Mitchell / Gold Creek	Zone Substation	Capacity	Install a 3rd transformer at Gold Creek Zone Substation OR construct a new zone substation at Mitchell to meet growth in maximum demand	>2024	TBC
Strathnairn	Zone Substation	Capacity	Construct a new Strathnairn Zone Substation	2025-26	TBC

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