Economic and Technical Modelling of the ACT Electricity Network

Base case Report

EPSDD

26 April 2022

→ The Power of Commitment

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Executive Summary

The global energy sector is transforming at a pace – driven by customers as they embrace new technologies, take control of their energy use and support action to decarbonised economies.

Achieving decarbonisation is a major task for any economy and especially for an emissions-intensive economy such as Australia. In November 2021, the international climate change conference in Glasgow took a step towards realising a carbon neutral future, by committing to delivering a long-term emissions reduction strategy premised on a long-term net zero target.

However, enacting a net zero strategy and achieving decarbonisation success will require current energy systems to transition away from a reliance on fossil fuels. A successful transition will require early action/'wins' and a sustained focus on implementing policy and supporting investment programs to reduce greenhouse gas (GHG) emissions and supporting resilient and sustainable communities.

This pivot away from fossil fuels is well underway within the Australian Capital Territory (ACT) and promises to reimagine the Territory's future energy systems – for the better. The ACT Government has set and achieved ambitious targets over the past decade, with the goal of achieving net zero GHG emissions by 2045.

Achievement of these targets has helped to fast-track emissions reduction and well positioned the Territory to take further credible action to reach net zero – but this will be challenging - and if a less than optimal path is chosen this may result in higher costs and a longer transition period.

The ACT Government has recognised that the next step up in emissions reduction, with a focus on 2045, will require changes to the Territory's energy production and use, whilst maintaining safety, security, reliability and quality of supply. This is important, as the largest remaining sources of GHG emissions are from transport and other stationary energy - specifically natural gas.

Removing natural gas offers an opportunity to rapidly decrease emissions, given that, as an energy source, it is emissions intensive and cannot easily be replaced with a zero emissions alternative. Identifying viable alternatives to natural gas and plotting the most appropriate pathway of transition to electrification that considers impacts to consumers and the existing electricity and gas networks, is critical.

This **Base case Report** (Stage 1 Report) contributes to the ACT Government's decision making whilst ensuring that emissions reduction policies and supporting programs enhance, not undermine, the socio-economic conditions enjoyed by Territorians.

This Report represents the results of economic and technical modelling of an ACT Government agreed base case, with assumptions based on business as usual (BAU), adjusted to reflect the current policy environment for a pathway to net zero (phase out of fossil-fuel-gas by 2045) and expected trends. The Report further sets out three realistic policy scenarios that, when modelled, will allow the ACT Government to select the transition pathway that will best contribute to a more resilient and sustainable energy system.

Key findings

Transformation of the energy distribution network

The ACT Government has committed to implementing and achieving clear, ambitious climate targets for establishing a predictable basis for a low-emission development pathway to support net zero emissions by 2045.

- The Territory has reduced its 1990 GHG emission levels by 45 per cent, exceeding its legislated 2020 target of 40 per cent. To achieve legislative forward targets, it will be essential to reduce emissions from both transport and natural gas use across the Territory.
- There is a critical need for the energy distribution network to play its role in delivering a more sustainable electricity system with reduced GHG emissions.
- Transformation of the energy distribution network will facilitate the transition to low emissions energy future whilst delivering high levels of energy security and reliability.
- The next decade is likely to see a step change in the adoption of new technologies including distributed energy resources – this will influence customer demand for energy network services.
- Efforts towards net zero emissions are expected to increase demand on the electricity grid because of an increased electrification of households and vehicles.

Base case modelling

Net zero carbon solutions for the Territory need to be underpinned by robust, modelled data that has regard to both the economic and technical implications and constraints of harnessing decarbonisation opportunities, whilst maintaining energy security and reliability.

- The outcomes of the modelling set out in this report will contribute to the Territory realising investment opportunities to build a more resilient and sustainable energy system that delivers lasting benefits by harnessing decarbonisation opportunities now and into the future.
- The base case modelling provides insight as to the effect of the current ACT Government climate change policies and objectives aimed at delivering a net zero emissions pathway and the impact on the ACT electricity and gas networks.
- Understanding these impacts is important to the development and construct of the strategic scenarios to be examined as options to further move and accelerate progress towards net zero emissions.

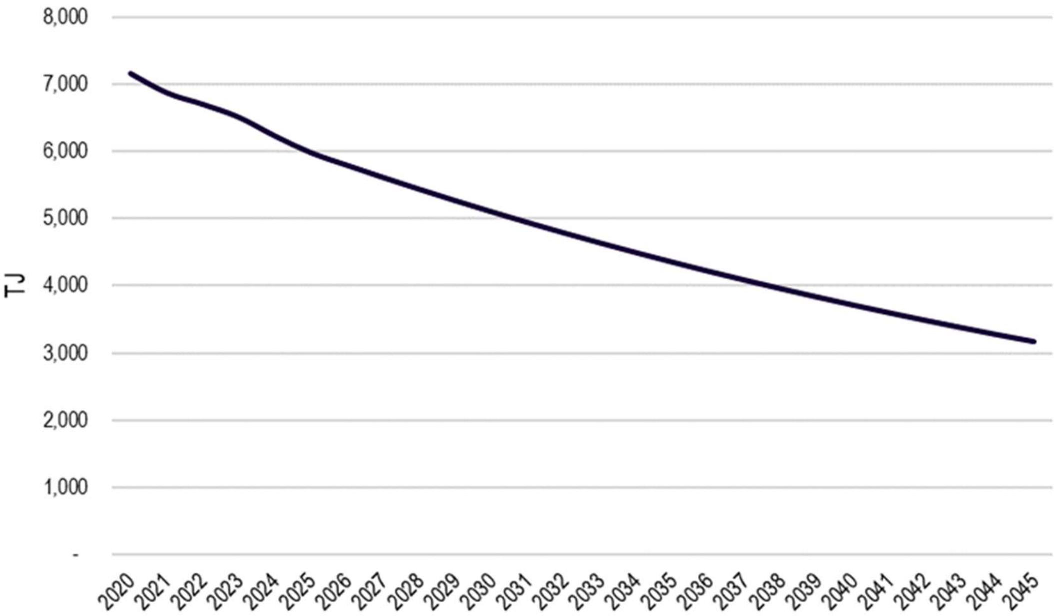
Gas market projections

Gas consumption

While overall gas consumption has been relatively stable over the past decade, consumption has been steadily declining on a per connection basis as indicated at Figure 1. Base case modelling indicates that the ACT's total gas consumption will drop from levels around 7,000 TJ currently to around 3,000 TJ by 2045 (based on the current energy policy environment):

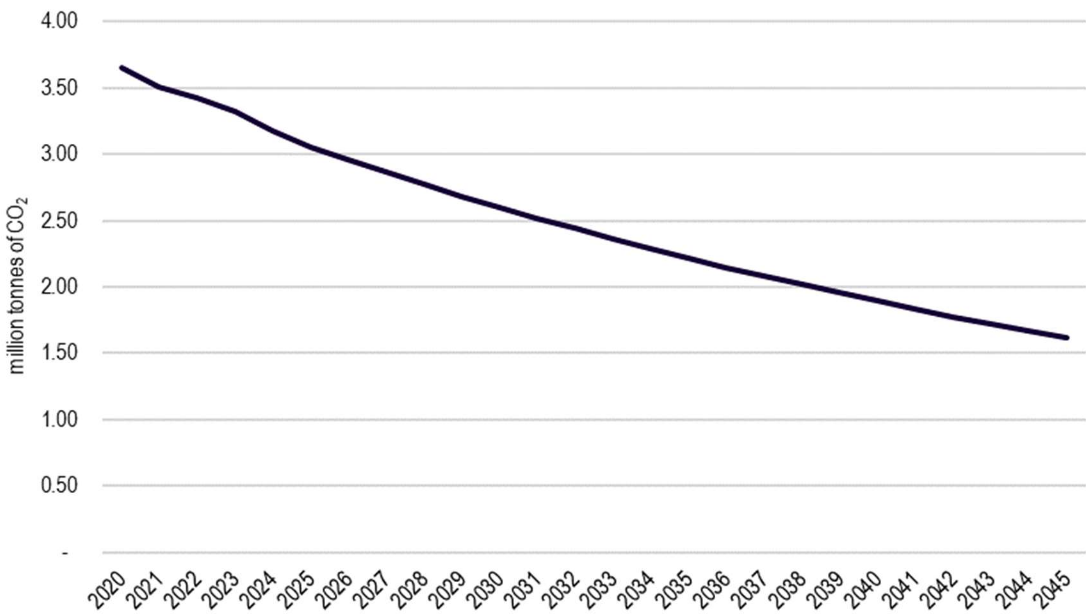
- this represents a decline of approximately 60 per cent
- most of the decline can be attributed to falling consumption per connection, coupled with a steady decline in connections from 2023 (due to ACT policy not permitting new connections post this time)
- this decline is a marked change from consumption over the past decade which has been relatively stable.

Figure 1 Projected total gas consumption - ACT



In line with projected gas consumption, emissions from the consumption of natural gas in the ACT are expected to fall from 3.5 million tonnes of CO_2 (current) to around 1.5 million tonnes by 2045 under the base case (see Figure 2).

Figure 2 Base case emissions from consumption of natural gas



Gas retail price

The total delivered gas retail price is projected to increase in real terms from around 3.3 cents/MJ to around 4.5 cents/MJ by the mid-2040s, mostly attributed to a reduction in throughput volumes and secondary effects from the wholesale gas price. The retail price would noticeably increase over the first 10-15 years (until the mid-2030s) reflective of the increasing distribution component because of declines in consumption volumes and wholesale price rises. However, the significant driver of the increase is the projected increase in distribution tariffs.

Investment in the gas network

The prospect of electrification scenarios creates uncertainty for owners of gas infrastructure assets in relation to the time that they will have to recover the costs of any investment required to ensure security and reliability of supply in the short- to medium-term, weakening incentives to invest in the natural-gas sector.

- With demand for natural gas projected to decline by around 60 per cent reduction in gas consumption by 2045 – the distribution network in terms of its long-term viability will be impacted including the consequences for gas prices.
- The AER is reviewing implications of shortening asset lives on regulatory parameters including depreciation schedules. This will have important implications for how Evoenergy operates the ACT network and the removal of natural gas from the energy mix across the Territory.

Hydrogen

Whilst the ACT is still likely to require significant supplies of natural gas for the next 10-20 years, there may be potential for hydrogen to replace natural gas consumption in the long term. Currently, hydrogen strategies tend to focus on large-scale industrial applications and export opportunities, with some pilot schemes exploring green gas blending into gas networks. Given the Evoenergy network is integrated into the broader east coast system, the potential for green gas penetration into the ACT is likely to follow the broader regional trend.
Complex challenges will need to be overcome if natural gas in the ACT's gas distribution system is to be replaced with hydrogen, although a blend of 10-20 per cent hydrogen would be readily achievable. Introducing of hydrogen offers an energy mix to support sustainability but will depend on the technical capability and capacity of the Evoenergy grid to support the distribution of hydrogen across the territory.

Consumer conversion costs. An important factor in how quickly consumers will transition away from natural gas to electrification or possibly hydrogen in the long term is the cost of converting appliances.

- Base case analysis suggests that when it comes to replacing gas appliances as they expire, less than half of the eligible gas appliance stock each year is replaced with electric appliances.
- The cost of running electric appliances is likely to be the key differentiating factor in persuading consumers to switch.
- In terms of the cost of purchasing gas appliances versus electric appliances and the cost of installation, the difference seems to be relatively minimal at this stage.
- Transitioning to hydrogen would incur much higher costs, but costs decline over time.
- Large scale hydrogen transition would require significant costs to convert gas connected properties to hydrogen only.

Electricity market modelling

The seasonal peak demand and annual energy forecasts for the ACT demand profiles consider past trends and relationships between residential and non-residential underlying demand. The modelling incorporates the:

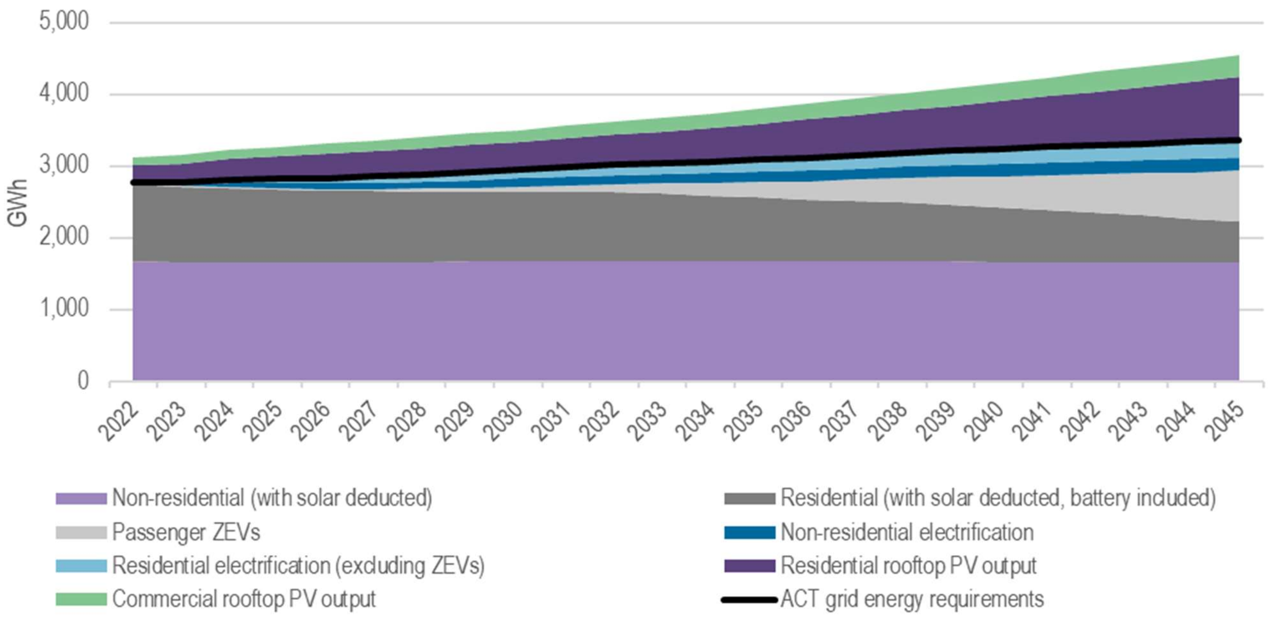
- projected uptake of rooftop Photovoltaic systems (PVs)
- projected uptake of Battery Energy Storage Systems (BESS)
- uptake of passenger Zero Emissions Vehicles (ZEVs) in line with 'conservative' EPSDD projections (as per the provided (confidential) Deloitte analysis)
- adjustments for new electrification initiatives such as electrification of the Canberra Hospital, CIT Woden, Light Rail Stage 2.

The base case incorporates the transition away from natural gas with the projected natural gas transition converted to electricity demand (using conversion factors and representative profiles for space heating, hot water, cooking and industrial processes) as:

- most gas consumption is for space heating the overall consumption profile is seasonal (winter peaking) and has a low load factor
- for residential customers, the remaining gas consumption is for hot water and cooking. For non-residential customers it is for hot water, cooking and industrial processes.

Final assumed annual energy and peak demand projections (Figure 3), derived from the assumed underlying demand, together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, result in an increase in electricity demand of 21 per cent by 2045, despite compensating for 60 per cent loss of gas demand.

Figure 3 Projected energy requirements (GWh) – by category



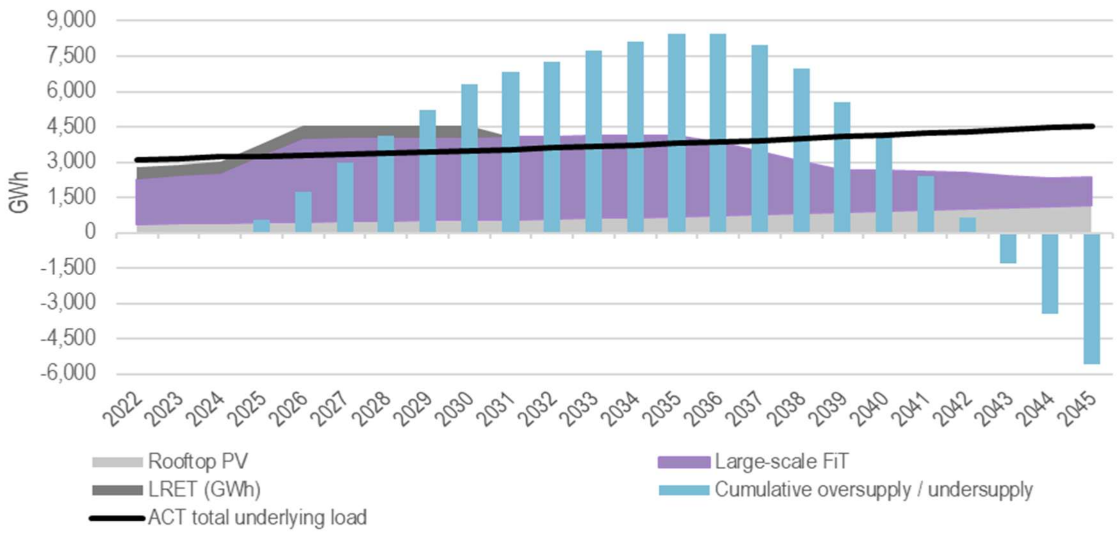
Note: non-residential electrification includes general natural gas transition of non-residential customer as well as electrification of specific commercial loads of Canberra hospital, Molonglo Commercial Centre, CIT Woden, Bus fleet and Light Rail stage 2.
Source: ACIL Allen

Key factors encompassed in this outcome include:

- delivery of 26 per cent of total demand through rooftop PV by 2045
- EVs comprise 41 per cent of car fleet by 2045 (producing no emissions, but adding to electricity demand)
- the continued hollowing out of the demand profile across daylight hours because of rooftop PV, and a growth in demand during the evening because of electrification
- the impact of storage on the demand profile is reasonably small given the level of uptake projected.

While the base case incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable, the projections show that the ACT will fall below 100 per cent renewable from 2037, declining to around 55 per cent of underlying demand by 2045 (see Figure 4). This suggests the Government could need to factor in a further auction of renewable electricity in around 2035-36. However, the current policy is that renewable electricity in excess of 100 per cent target is 'banked' with credits carrying over to future years. These credits offset the need for additional purchases up until 2043. Furthermore, the National Electricity Market (NEM) is projected to source more of its generation from renewables over time – increasing from around 30 per cent currently to a projected 70 per cent by 2045. This change will largely offset the continuing need to purchase 100 per cent renewable electricity, if taken into account.

Figure 4 ***Projected contribution by category to 100% renewable energy (GWh)***



Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis:

Electricity system network analysis

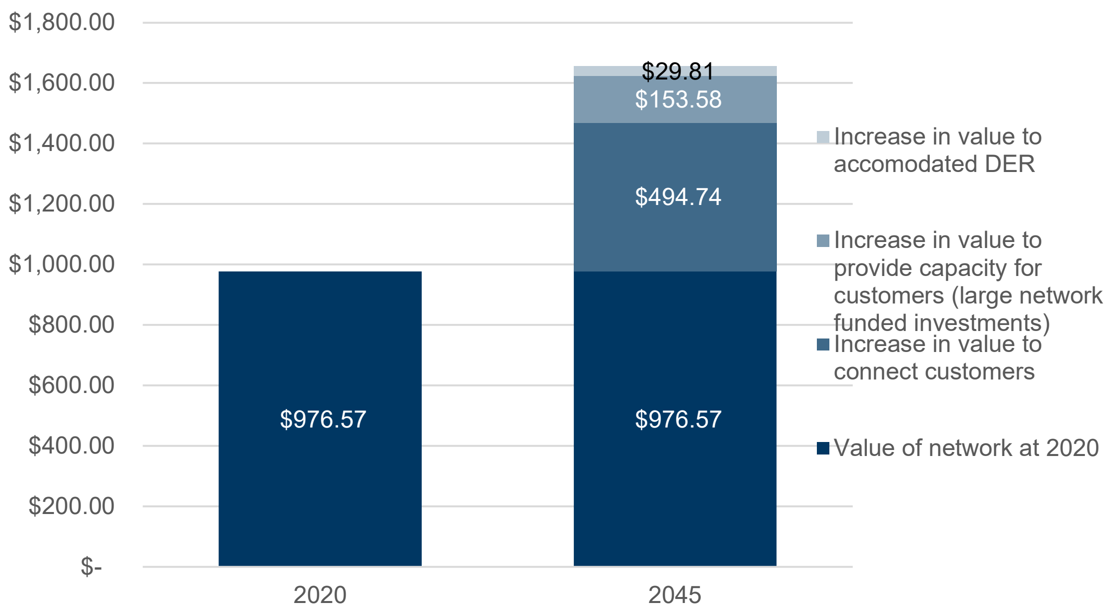
To maintain the existing level of safety, quality, reliability, and security of supply to energy users in the ACT, investment in the electricity system will be required:

- this investment will be primarily driven by growth in network demand due to the growing population of the ACT and, to a lesser extent, the forecast dependence on electricity for heating in the absence of gas and recharging electric vehicles
- this growth in demand will be offset, to varying degrees, by improvements in energy efficiency and increased penetration of rooftop PV systems, coupled with batteries

- investment identified in the ACT network in the base case is predominantly located in the areas of high population growth in the ACT – many low population growth areas are not expected to see significant investment during the period analysed
- there is an element of uncertainty in some elements that factor into the changes in the asset base beyond the network investments themselves (such as escalation, de-rating and retirements)
  - for the purposes of modelling the range of possible realistic outcomes has been determined, but the most conservative case scenario, leading to the highest growth in asset base, has been used, given it will have the greatest impact on customer tariffs.

However, if a more aggressive approach to the transition to a net zero emissions future is adopted it will likely increase investment in both the high and low population growth areas. The increased electrification is likely to lead to earlier network investments in areas of low population growth and increased augmentation beyond the base forecast in areas of high growth. The base case demand forecast will require investment of an additional $678 million in the network to 2045 (up from the 2020 valuation of $1,654 million). The relative magnitude of the growth in the various segments of the network are shown in Figure 5 below.

Figure 5 ***Change in value of the distribution asset base 2020-2045, $ million***



Supporting the net zero pathway

The base case modelling provides for a holistic view of current electricity network capabilities and constraints, and how future transformational changes to natural gas, transport and electricity consumption and generation are likely to impact the network and consumers. Balancing electrification actions will be critical.

Gas market. The Government's electrification policy is driving the projected 60 per cent decline in gas use from 2023 reflected in falling consumption per connection and a steady decline in connections.

- the projected decline will place pressure on the distribution network in terms of its long-term viability, and will have consequences for gas prices, future investment in the market and the current regulatory regime

- there is also an opportunity to accelerate this decline through placing further policy limitations around new connections or incentivising consumers to adopt higher levels of electrification.

Notwithstanding the caveats in relation to the gas market discussed at Chapter 5, bringing forward gas transition represents an opportunity to deliver the net zero emissions pathway quickly. Accordingly, this is pursued as an option in the scenarios to be modelled.

Electricity market. Opportunities and constraints in relation to electricity will occur in both the electricity market and the network.

- Bringing forward the uptake of ZEVs in the ACT represents a significant opportunity to pursue the net zero emissions pathway. There are a range of financial incentives and regulatory levers the Government could use to drive stronger uptake of EVs. However, the timing of these will need to be carefully calibrated to the development of the market to ensure demand does not outstrip supply.
- Transitioning households and commercial clients from gas is projected to have a reasonable impact towards reducing emissions.
- Increasing the number of electric buses and/or developing additional Light Rail are not seen as key opportunities in driving towards the net zero emissions outcome – as the electrification of the total fleet of buses is projected to have a very small (~one per cent) impact as a proportion of total ACT electricity demand. By comparison, the impact from passenger EVs is projected to be around 20 per cent of total ACT energy requirements by 2045.
- There is the opportunity to effect modest increase in the penetration of residential and commercial rooftop solar PV.
- Household batteries are projected to reach around 25 per cent of eligible households by 2045.

Electricity retail bill impacts

ACT electricity retail prices have been projected by customer type with the key components including a wholesale component, a network component, and a retail component. Bringing together these three components, the projected retail prices were determined.

- The modelling suggests that real retail prices for residential, LV commercial and HV customers are projected to increase by nine per cent, 19 per cent and five per cent, respectively.
- A key driver of the increase is the projected increase in wholesale and distribution network costs
- These increases are partially offset by declining large FiT payments – moving to revenues from around 2038 as average spot prices rise – compared with modelled CPI of 2.5 per cent.
- Over the period to 2035, projected retail bills for residential, LV commercial, and HV customers decline by five per cent, three per cent and nine per cent, respectively (reflecting projected declines in large FiT payments and costs associated with the Commonwealth Government's environmental schemes).
- Over the period from 2035 to 2045, projected retail bills for residential, LV commercial, and HV customers increase by 25 per cent, 22 per cent and 24 per cent, respectively (reflecting projected increases in wholesale electricity prices and distribution network costs).

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Glossary

ACRONYM	DEFINITION
ABS	Australian Bureau of Statistics
ABARE	Australian Bureau of Agricultural and Resource Economics
ACT	Australian Capital Territory
ActewAGL	ActewAGL is a multi-utility joint venture company providing utility services in the ACT and NSW
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APA Group	APA Group is a natural gas transmission company
ARENA	Australian Renewable Energy Agency
AUD	Australian Dollar
BAU	Business as Usual
Bbl	Barrel
BCB	Big Canberra Battery
BCA	The Building Code of Australia (BCA), in the National Construction Code series, contains technical provisions for the design and construction of buildings and other structures (including those relating to energy efficiency)
BESS	Battery energy storage systems
CAPEX	Capital expenditure
CCGT	Combined-cycle gas turbines p
CCS	Carbon Capture and Storage
CIT	Canberra Institute of Technology
CIE	Centre for International Economics – an independent consultancy firm that prepared demand forecast for Evoenergy's last access arrangement.
CMTEDD	Chief Minister, Treasury and Economic Development Directorate
CNG	Compressed Natural Gas
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent - a term for describing different greenhouse gases in a common unit

ACRONYM	DEFINITION
COAG	Council of Australian Governments
COP	Coefficient of Performance - a performance rating indicating effectiveness in transferring heat versus electrical consumption
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed energy resources
DUID	Dispatchable unit identifier - a semi-scheduled generating unit or a non-scheduled generating unit (AEMO)
DUOS tariffs	Distribution Network Use of System tariffs
EGP	Eastern Gas Pipeline
EPSDD	Environment Planning and Sustainable Development Directorate
ESCRI	Energy Storage for Commercial Renewable Integration
ESOO	Electricity Statement of Opportunities
ESB	Energy Security Board
EV	Electric vehicle
FiT	Feed-in tariff
FY	Financial Year
GEMS	Greenhouse and Energy Minimum Standards (statutory requirements providing a streamlined nationally-consistent approach to appliance energy efficiency)
GHG	Greenhouse gas
GJ	Gigajoule
GPG	Global power generation
GSOO	Gas Statement of Opportunities
GW	Gigawatt
GWh	Gigawatt hours
HV	High voltage
ICE	Internal combustion engine
ICRC	Independent Competition and Regulatory Commission

ACRONYM	DEFINITION
ISP	Integrated System Plan
km	Kilometres
kt	Kilotonnes
kV	Kilovolt
kW	Kilowatt
LGC	Large-scale generation certificate
LHS	Left Hand Side
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
LULUCF	Land Use, Land Use Change and Forestry
LRMC	Long Run Marginal Cost
LV	Low voltage
MJ	Megajoule
MLF	Marginal loss factor
MVA	Mega volt amperes
MW	Megawatt
NA	Not applicable
NCC	National construction code
NEC	National Energy Commission
NEG	National Energy Guarantee
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMS	National Electricity Market of Singapore
Neoen	Neoen is an independent company, producing renewable energy
NESA	National energy security assessment
Net zero emissions	Achieving an overall balance between greenhouse gas emissions produced and greenhouse gas emissions taken out of the atmosphere.
NPV	Net present value
NSLP	Net System Load Profile

ACRONYM	DEFINITION
NSW	New South Wales
NUOS tariffs	Network Use of System tariffs
OLTC	On-load tap changer
OPEX	Operational expenditure
PAGA	Parliamentary and Governing Agreement (ACT Government 10th Legislative Assembly for the Australian Capital Territory: Agreement between the Australian Labor Party ACT Branch, and The ACT Greens)
PJ	Petajoule
POE	Probability of Exceedance
PTRM	Post Tax Revenue Model
PV	Photovoltaic system
QNI	Queensland-NSW Interconnector
RAB	Regulated asset base
RECs	Renewable Energy Certificates
REZ	Renewable Energy Zones
RHS	Right Hand Side
RINs	Regulatory Information Notices
Sincal simulations	PSS®SINCAL – simulation software for analysis and planning of electric and pipe networks
SRES	Small-scale Renewable Energy Scheme
SRMC	Short run marginal cost
TJ	Terajoule
TUOS tariffs	Transmission Network Use of System tariffs
Underlying consumption and demand	All the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' distributed photovoltaics (PV) and battery storage.
USD	United States dollar
V2G	Vehicle-to-grid
V2H	Vehicle-to-home
VNI	Victoria-NSW Interconnector

ACRONYM	DEFINITION
VPPs	Virtual Power Plants
WACC rate	Weighted average cost of capital rate (the rate that a company is expected to pay on average to finance its assets)
WESM	Wholesale Electricity Spot Market
Wobbe index	An indicator of the interchangeability of fuel gases such as natural gas, liquefied petroleum gas
ZEV	Zero emissions vehicle

1. Introduction

Clear and ambitious climate targets provide a predictable basis for a low emission development pathway for Government. The ACT Government is pursuing an ambitious climate policy and will continue to do so. The Government's long-term target is for the ACT to be a low-emission society by 2045 where resource use is efficient, and business and industry remain competitive.

This will require a transformation of the energy network. Cooperation and coordination across government, industry and community will be essential to develop a roadmap that reduces GHG emissions and builds a resilient energy system that contributes to a sustainable society.

1.1 Purpose of the Report

The Environment Planning and Sustainable Development Directorate (EPSDD) has commissioned GHD and ACIL Allen to deliver two (2) reports as part of this study to assess the impact that the Territory's climate change policies and objectives on the energy transformation roadmap to 2045:

- this **Base case Report** (Stage 1 Report) represents the results of economic and technical modelling of the agreed base case and sets out three realistic policy scenarios (with activities) to be modelled as part of the second phase of the project.
- Modelling of these three scenarios and economic impact will be undertaken in the next phase of the project with results to be detailed in the **Strategic Report**.

The objective of the modelling is to ensure that the Territory has a holistic view of current electricity network capabilities and constraints, and how future changes to natural gas, transport and electricity consumption and generation are likely to impact the network and consumers.

The aim of the strategic advice is to provide the Territory with realistic scenarios on how it may achieve its policy objectives, whilst maintaining 100 per cent renewable electricity and balancing network capabilities, energy security, quality of supply and costs to consumers.

1.2 Approach

1.2.1 Data analysis and modelling

Energy models (both economic and technical) will be essential for the ongoing development and implementation of the ACT's 2045 deep decarbonisation pathway.

For this **Base case Report**, we undertook detailed modelling of the electricity network against a base case with consideration of current and expected market trends, and parameters drawn from existing Government policy settings/announcements. Modelling focused on:

- Electricity Network – constraints and opportunities in terms of capacity, demand, impact, reliability, quality of supply and security
- Gas projections – options and impact of backing out gas in the energy mix and/or moving to 'green' gas.

Chapter 3 sets out the detailed methodology used to model the base case.

The **Strategic Report** will build on the outcomes to date and incorporate the economic modelling of electricity (and gas) network impacts, including upgrades, offsets, and total costs to stakeholders. The alternate scenarios will be modelled and policy and regulatory options to realise the desired outcomes will be examined.

1.2.1 Policy considerations

There are an array of ACT Government policy commitments and strategies that have been considered in the base case's parameters and the alternate scenarios modelled. The degree of relevance and impact varies considerably.

Appendix A details the key policies considered in the development of the three scenarios, the modelling of the base case and inclusion in assumptions.

1.2.2 Assumptions

The assumptions that have underpinned the analysis and modelling findings set out in this report are detailed at Chapter 4. Besides ACT Government policy commitments and strategies, a range of Commonwealth Government commitments which relate to the energy market have been built into the core modelling assumptions set out in this report.

1.2.3 Consultation

GHD and ACIL Allen (the Consultant) engaged with ACT Government stakeholders to inform the development of the base case and scenario options. A listing of stakeholders is provided at Appendix D. Consultation focused on the considerations of:

- the outlook for greenhouse gas emissions in the context of current and future Government policies
- potential policy options to deliver changes in the Territory's emission profile and their suitability for deployment
- potential barriers (technical, commercial, regulatory) to deployment of policy options and views on the role of Government in addressing these
- approaches used in other jurisdictions which could be applied
- views on the ability of the ACT economy to transition to different emission trajectories over various timeframes.

1.3 Limitations

GHD and ACIL Allen has prepared this report for EPSDD to be used and relied on by EPSDD for the purpose agreed between GHD and EPSDD as set out in Section 1.1 of this Report.

GHD and ACIL Allen otherwise disclaims responsibility to any person other than EPSDD arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

The services undertaken by GHD and ACIL Allen in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD and ACIL Allen has no responsibility or obligation to update this report to account for events or changes occurring after the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD and ACIL Allen described in this report. GHD and ACIL Allen disclaims liability arising from any of the assumptions being incorrect.

2. Project Context

Decarbonising economies to combat the negative impacts of climate change is a complex journey. It requires economies to navigate away from how they currently operate, towards a net zero emissions model.

For this to occur, current energy systems, process, infrastructure, and transportation decisions across every industry sector will need to be challenged, reviewed and adapted. A successful transition towards a net zero emissions economy therefore requires a robust strategy, as well as the engagement and trust of stakeholders and the community.

The ACT Government is showing what is possible through a commitment to a net zero emissions pathway by 2045. This Chapter summarises the ACT Government's emission reduction commitment including consideration of the factors that will have an impact on achieving a carbon neutral pathway by 2045.

2.1 Responding to and planning for future energy needs

There are significant challenges in understanding and planning for future energy needs. The energy sector is undergoing a fundamental transformation because of accelerating efforts to decarbonise the sector. There are several factors at play in this effort:

- the rapid decline in renewable generation costs in the electricity sector, especially wind and solar PV generation technologies
- the upscaling of Government programs to support renewable and storage investment, including direct support to generators and storage systems and indirect support through the development of renewable energy zones
- the growth in technologies to support distributed energy resources (DER) which can include rooftop solar PV, home and suburban scale batteries, smart meters, EVs, and demand response applications
- utility-scale energy storage technology is beginning to penetrate the market as battery storage begins to move down the cost curve and pumped storage is pursued
- coupled with the growing uptake of energy storage technology, there is an increasing array of energy services firms that offer sophisticated energy management systems, which will reduce both domestic and commercial energy demand, particularly on the level of demand for electricity from the grid
- with both the east and west coast gas markets being major exporters of liquefied natural gas (LNG), export prices influence the prices paid for domestic gas
- the expected uptake in the use of hybrid and electric vehicles will significantly affect demand for liquid fuels and demand for electricity - similarly, the use of hydrogen (particularly for heavy transport) could reduce demand for diesel in the medium to long term
- the potential for alternative green gas (renewable natural gas) to play a role in the future energy mix, even though:

  - while hydrogen strategies tend to focus on large-scale industrial applications and export opportunities, some pilot schemes are exploring green gas blending into gas networks
  - the technical challenges, cost and current ACT industrial and commercial profile may limit the commercial viability of green gas in the ACT
  - with the Evoenergy network integrated into the broader east coast system, the potential for green gas penetration into and as such the ACT is likely to follow the broader regional trends
- gas pipelines also have the potential to effectively become storage systems if there is excess renewable electricity generation however full in-depth analysis of the practical limitations of this has not been conducted.

These trends are amplified as the sectors and the markets become increasingly complex. Market operators and regulators will look to factor in these technological changes in their market forecasts and outlook.

2.2 ACT's emission reduction targets and net zero emissions commitment

2.2.1 ACT energy and emission profile

2.2.1.1 Current energy distribution networks

The ACT's energy is delivered via both electricity and natural gas distribution networks comprising:

- an electrical distribution network is owned and operated by Evoenergy, comprising over 2,300 km of overhead lines and 2,600 km of underground cables, supplied approximately 2,855 GWh in 2019-20 (57 per cent of the total energy supplied)
- a natural gas distribution system network is owned by Evoenergy Gas and operated by Jemena with approximately 4,000km of pipelines which supplied approximately 7,896 TJ (2,193 GWh) in 2019-20 (43 per cent of the total energy supplied).

The ACT Government's commitment to 100 per cent renewable electricity, while having no grid scale electricity generators within its borders, requires it to purchase of renewable energy certificates through contracts with wind and solar farms outside of the ACT.

2.2.1.2 Current emissions profile

The ACT's Greenhouse emission inventory for the period 2019-2020 was estimated at 1,684 kilotonnes[1] of carbon dioxide equivalent (kt $C0_2$-e) as shown in Table 1. With the ACT's electricity supply being 100 per cent renewable, the largest remaining sources of greenhouse gas (GHG) emissions are transport estimated at over 60 per cent and other stationary energy at over 20 per cent. Use of natural gas accounts for almost 99 per cent of other stationary combustion emissions. Most natural gas consumed in the ACT is used for space heating in residential and commercial/institutional buildings, and much of the remainder is used for water heating.

1 Strategy. Policy. Research: "*ACT Greenhouse Gas Inventory for 2019-20",* October 2020

Table 1 Current emissions profile for ACT

Emission Source	Emissions Source in 2019-20, kilo tonnes CO_2-e	Share of total emissions excluding LULUCF
Electricity	0	0%
Other Stationary Energy	367.7	20.6%
Transport	1,018.5	57.2%
Fugitive emissions	41.1	2.3%
Industrial processes	213.5	12.0%
Agriculture	21.7	1.2%
Waste	118.2	6.6%
Subtotal excluding LULUCF	1,781	105.8%
LULUCF	-97	-5.8%
Total including LULUCF	1,684	100%
Source: ACT Greenhouse Gas Inventory (2019-2020)		

2.2.2 ACT Climate Change Strategy (2019-2025)

A transition to a net zero emissions economy is a major challenge that requires an adaptive and innovative approach to implementing emission reduction strategies. The ACT Government has set a vision of being a "*leading net zero emissions Territory by 2045*" contributing to the global challenge of climate change.

> *…." the ACT will be powered by 100% renewable electricity and will continue to lead in finding innovative solutions for energy demand management and energy security. This will support a strong and diverse zero emissions economy, establishing the ACT as a zero-emissions investment hub. Homes and commercial buildings will be climate wise; that is, they will be efficient and capable of being comfortable in all seasons and will generate zero emissions having transitioned off natural gas. The city will be serviced by an integrated transport network that encourages cycling and walking, provides user-friendly zero emissions public transport and supports a zero-emissions vehicle fleet. The impacts of a changing climate on people, infrastructure and services will be well-managed and urban heat impacts will be reduced by an established network of street trees, waterways and parks supported by healthy soils. Productive farmlands, forests and biodiverse nature reserves will be sustainable and resilient to the changing climate"….*
>
> *ACT Climate Change Strategy (2019-2015)*

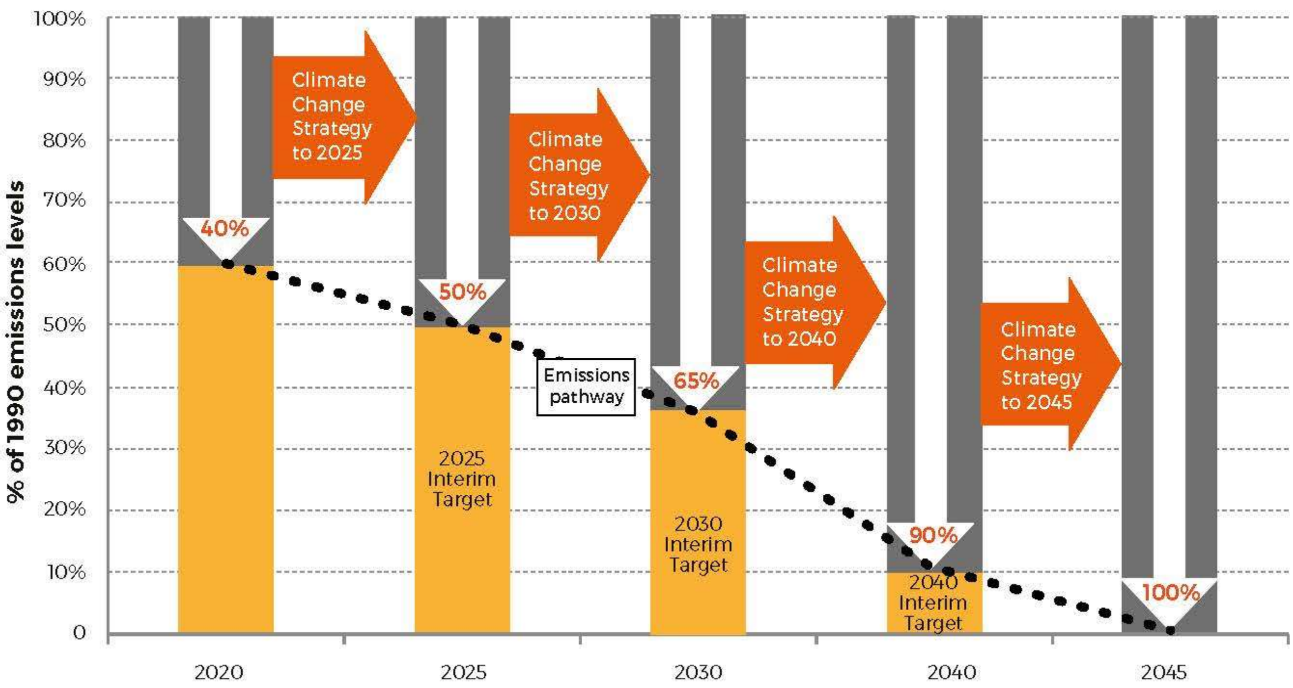
The Government's Climate Change Strategy (2019-25) sets out a series of GHG emission reduction targets to support a low emissions future. Underpinning the strategy is a consideration of factors such as reducing energy costs, managing impacts on employment and businesses, and providing tailored information and support for low-income households.

The Government aligns the strategy with the ACT Planning Strategy 2018, the ACT Housing Strategy (2018) and the Integrated Transport Strategy. It is also aligned with the goals of other related Government policies, including in health, waste management and nature conservation. Together, these policy documents provide the framework for achieving a smart, sustainable, and net zero emissions Territory by 2045.

The Climate Change Strategy outlines the actions the ACT Government will take to meet its legislated emission reduction target of 50–60 per cent (below 1990 levels) by 2025 and establishes the transition pathway for achieving net zero emissions by 2045. As shown in Figure 6, the targets as set out in the strategy (to reduce emissions from 1990 levels) are:

– 40% by 2020
– 50–60% by 2025
– 65–75% by 2030
– 90–95% by 2040
– 100% (net zero emissions) by 2045…

Figure 6 ACT's emission reduction targets to 2045



Source: ACT Climate Change Strategy 2019-2025

2.2.3 Mapping a pathway to net zero emissions by 2045

2.2.3.1 Action against emission targets

The ACT has legislated its emission reduction targets under the *Climate Change and Greenhouse Gas Reduction Act 2010*. These targets were first introduced in October 2010. They have been regularly revised to reflect realistic emission targets that will establish the foundation to achieve carbon neutrality by 2045, or earlier.

Since 2012-13, the Government has worked towards achieving emission reductions measurable against the three key legislated targets of total emissions, emission per capita and renewable share of electricity supply. Achievement against the targets is summarised at Table 2. Results indicate that all three targets have been achieved, specifically:

- an emission reduction to 40 percent below 1990 emissions – 45 per cent achieved
- 100 per cent renewable electricity supply by 2020 – achieved
- per capita emissions have not exceeded 2012-13 levels and have steadily declined.

Achieving these targets has driven innovation in energy and transport industries across the Territory whilst assisting industry and the community to save energy costs.

Table 2 Achievement against emission reduction targets

Year	Total emissions (kt CO_2-e)	Change from 1989-90	Emissions per capita (kt CO_2-e)	Renewable share of electricity supply
1989-1990	3077	0%	11.0	NA
2012-2013	4143	35%	10.9	17.3%
2013-2014	4120	34%	10.7	18.6%
2014-2015	4204	37%	10.7	17.8%
2015-2016	4158	35%	10.4	17.0%
2016-2017	4169	36%	10.2	19.7%
2017-2018	3967	29%	9.5	20.7%
2018-2019	3945	28%	9.3	23.4%
2019-2020	1684	-45%	3.9	100%
Source: ACT Greenhouse Gas Inventory (2019-2020)				

2.2.3.2 Requirement for ongoing transformation across the ACT economy

Following its 2020 achievement of 100 per cent renewable electricity supply, the ACT Government has continued to work towards ambitious emissions reduction targets, focused on a resilient and sustainable Territory. The path to achieving net zero emissions by 2045 will require transformation across most sectors of the economy. Achieving this transformation will require early action/'wins' and a sustained focus on implementing policy and supporting investment programs to reduce emissions.

Achievement of the targets set out in Figure 6 will require a focus on the transport and energy sector (natural gas) where a significant and rapid emissions reduction will be necessary. Cuts in these sectors are critical if the ACT Government is to achieve its legislated targets through to 2040 and establish the foundations for achieving net zero emissions by 2045. Natural gas, in particular offers an opportunity to rapidly decrease emissions given, the potential quantum in terms of tonnes of CO_2 and percentage change as illustrated at Figure 2 and Table 1.

The ACT Government's 100 per cent renewable electricity target is a perpetuity commitment from 2020, meaning that there will be an ongoing need to buy new renewable electricity sources to manage any increase in ACT electricity consumption.

As the energy transition accelerates, the decarbonisation of other sectors also needs careful planning of the interface with the energy system. This will require the right incentives, policies, and technologies to make load more flexible in order to maximise the value that the energy system can deliver.

The Government has committed to exploring alternatives to natural gas and decide the most efficient and viable transition pathway that considers impacts to consumers and the existing electricity and gas networks. Fuel-switching, in the form of electrification as a direct substitution for fossil fuels, is a cost-effective decarbonisation option for sectors that use energy.[2]

There may also be scope for the Territory's existing gas infrastructure to play a role in this transition by gradually incorporating a share of renewable natural gas and/or hydrogen into the system (in accordance with existing policy commitments). However, the introduction of hydrogen into gas networks to a significant extent (that is hydrogen blending at greater than 20 per cent) is limited by technological, network and cost barriers, coupled with the availability and commercial development of appropriate appliances.

The purpose of this report is to inform and support the ACT Government's decision making. Prioritising changes in the transport and natural gas sectors does not eliminate the need for emission reduction actions across other sectors – as all will contribute to achieving a net zero emissions future for the Territory.

2.2.3.3 Factors impacting transformation

For many customers, the carbon neutral pathway through to 2045 will bring changes to the way they consume, produce and value electricity and related network services. Consumer demand is a key consideration in the assessment of supply adequacy and the key drivers affect residential, business mass market, and industrial consumer segments differently. There is expected to be a shift in customer value drivers, influenced partly by the uniquely high penetration of distributed energy resources in Australia, including increasing adoption of solar PV panels, the increasing affordability of energy storage and the growing trend towards growing digitisation and customisation of services.

Unlike the transition to renewable electricity, reducing emissions from transport and natural gas will be impacted by factors associated with, but not limited to:

- increasing diversity in customer energy use and engagement, not well correlated with traditional factors like socio-economic groups or specific business types
- customers directly investing to reduce consumption, generate, store and control electricity usage via on site distributed energy resources for cost, independence, reliability, and environmental goals
- changes in the traditional supply chain, with contracts with a single supplier being replaced by multiple commercial relationships in new energy service markets.

[2] Reedman, L.J., Chew, M.S., Gordon, J., Sue, W., Brinsmead, T.S., Hayward, J.A. and Havas, L. 2021. Multi-sector energy modelling, CSIRO, Australia – a report prepared for AEMO which concluded "*The combination of emissions abatement potential from a decarbonised grid, and accompanying energy efficiency benefits, makes electrification an attractive decarbonisation option* …"

3. Methodology

This Chapter provides an overview of the methodology employed for the purposes of modelling the base case, predicated on BAU assumptions in terms of electricity, gas, and transport fuels market developments, with adjustment for firm policy commitments/actions by the ACT Government.

3.1 Modelling approach

The project required the provision of a **Strategic Report** that analysed differing policy scenarios which meet the Territory’s emissions objectives. The outcomes will provide an understanding of the impact of climate change policies and objectives on the ACT electricity network. The key services delivered include:

- Electricity Network Modelling – highlighting constraints and opportunities in terms of capacity, demand, reliability, quality of supply and security
- Economic Modelling – modelling of electricity network impacts, including upgrades, offsets, and total costs to stakeholders
- Scenario development, analysis and advice – on proposed energy policy options and activities to achieve the Territory's objectives.

In accordance with the required services, this **Base case Report** sets out the results of detailed modelling of the electricity network, against a base case to incorporate current and expected market trends, overlaid with parameters drawn from existing Government policy settings/announcements.

Given the clear policy objective of “*phasing out of fossil-fuel-gas in the ACT by 2045*”, which could be achieved through either electrification or displacement of fossil-fuel-gas by ‘green gas’ (hydrogen and/or biomethane), or a combination of both. Furthermore, the limited industrial demand for hydrogen in the ACT, coupled with the constraints to introducing green gas into the gas network, are not likely to materially impact on electricity demand. As such, it is not factored into the electricity modelling.

The work includes limited modelling of the gas network and some advice regarding the options/costs associated with possible decommissioning or expansion of the gas network (based on green gas). Green gas options are analysed qualitatively, but not incorporated into any quantitative gas modelling. This work is beyond the current scope of the project.

The gas demand work of the project involved two distinct components:

- developing a simple projection for ACT gas consumption through to 2045 (natural gas consumption is assumed to be effectively phased-out by that date in line with the Government’s policy) - this projection will be based on historical trends in gas demand, and the results will inform the electricity network modelling
- gas market modelling to understand the impact on wholesale gas prices from the ACT transitioning from natural gas by 2045 – these wholesale gas price forecasts are used to understand the impact on customer bills over the forecast period.

Modelling of the liquid fuels market is not included in the scope of the project. The uptake of EVs (and possibly hydrogen fuel cell electric vehicles) will potentially lead to substantial reductions in the demand for gasoline and diesel.

Assumptions in relation to penetration rates of electric vehicles are incorporated into the base case and the scenarios, but the impact on transport fuels and any reduction of GHG emissions from the transport sector will not be modelled, notwithstanding that transport is the largest sector contributing to ACT emissions (as illustrated at Table 1). Even with full electrification of the vehicle fleet, liquid fuels will continue to contribute to the ACT's emissions profile (i.e. through aviation fuels, commercial and industrial use of oil, etc.).

While the economic modelling provides a holistic view of the electricity network impacts, including the total costs (i.e. incorporating any costs to consumers to upgrade appliances, plumbing, wiring etc.) to stakeholders (consumers, Evoenergy and Government), it does not address all whole of economy impacts. For instance, it will not capture costs associated with the decommissioning of gas and transport fuel assets like service stations nor assess the relative economic impact of converting from liquid fuels to electrification, such as the impact of changes in freight costs on the price of goods and services delivered.

3.2 Simulation models

ACIL Allen's in-house simulation models, *PowerMark* and *GasMark* were used for the detailed modelling of the electricity network against the base case as set out in this report. Further detail regarding *PowerMark* and *GasMark* is provided in Appendix B.

3.3 Key data inputs

Modelling and analysis outcomes provided in this report were developed using the key data inputs summarised at Chapter 4 and at Appendix C. The data sources were provided predominately by the ACT Government and Evoenergy.

3.4 Consultation

Consultation with stakeholders was undertaken throughout this project to inform the development of the base case and scenario options. Further detail is provided at Chapter 1, Section 1.2.1 and Appendix D.

4. Base case parameters

This Chapter is structured to address the core assumptions first (that is those applying to the NEM as a whole that impact the ACT – in effect BAU) and then to incorporate ACT specific considerations arising from Territory policy settings.

4.1 Base case modelling core assumptions

The core assumptions used in the modelling of the electricity and gas markets in Section 4.2 and Section 4.3 are outlined, respectively. ACT specific assumptions are detailed as Section 4.4. The assumption tables identify which of the assumptions have a major impact, a moderate impact or a minimal impact on the outcomes from the market modelling. We set out the basis for these assumptions in the following sections.

4.1.1 Basis for core assumptions

We have examined various energy reports to develop a consensus view on the energy projections to 2045 and to inform the development of plausible, defensible scenarios (including the base case) for the future shape of the ACT energy sector. These reports include (but are not limited to):

- AEMO 2021 Input, Assumptions and Scenarios which are currently applied in the Australian Energy Market Operator's (AEMO) forecasting and planning activities including the NEM Electricity Statement of Opportunities (ESOO), Gas Statement of Opportunities (GSOO) and Integrated System Plan (ISP)
- AEMC 2018 – wholesale electricity modelling undertaken by the Australian Energy Market Commission (AEMC) for its 2018 Residential Electricity Price Trends Review
- CSIRO eFuture – a modelling platform first released with the Australian Government's 2012 Energy White Paper
- Finkel 2017 – modelling undertaken for the Independent review into the future security of the National Electricity Market: Blueprint for the future
- ACIL Allen 2018 – emission projection modelling of the National Electricity Market (NEM) undertaken for the Commonwealth Government
- ESB NEG 2018 – modelling undertaken for the Energy Security Board (ESB) as part of the development of the National Energy Guarantee (NEG)
- ACIL Allen 2019 – national energy security assessment (NESA) projections and scenarios modelling undertaken for the Commonwealth Government
- GenCost 2020-21 – the report is a collaboration between the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and AEMO to deliver an annual update of electricity generation and storage costs.

4.1.1.1 Overarching policy/Commonwealth initiatives

There are several recent Commonwealth (or COAG) energy market policy announcements and reforms including:

- **gas-fired recovery** – to reset the east coast gas market and create a more competitive and transparent Australian Gas Hub by unlocking gas supply, delivering an efficient pipeline and transportation market, and empowering gas customers
- **gas supply strategy** – to improve public availability and accessibility of rigorous science and factual information on all types of gas sources and extraction methods; consider regulatory frameworks that effectively manage the risks and address issues for development of onshore conventional and unconventional gas, offshore gas, and underground gas storage
- **gas market reform** – to improve transparency in the gas market, to facilitate competition between producers and better information for purchasers
- **reliability and security measures** – interim measures on system security; implementation of Renewable Energy Zones (REZ) Planning Rules; Distributed Energy Resources technical standards and integration plan; and Post 2025 Market Design for the NEM.

To the extent that these actions directly impact the market model outcomes, they are incorporated into the parameters accessed through NEM/AEMO data (post 2025 market recommendations are not incorporated into the base case because they are only recommendations at this stage).

The Commonwealth Government also provides grant funding to advance energy efficiency and other initiatives for example funding for renewable energy projects through ARENA, energy efficiency projects, etc. Given this support is generally delivered through competitive processes it is not possible to anticipate the extent to which potential ACT applicants may be successful and in what areas. In relative terms, the impact is not considered material and hence we do not include it in the modelling.

4.1.1.2 Liquid fuels

As stated above, we will not model the liquid fuels market. However, there are several factors relating to the ACT transportation market which will need to be factored into the electricity market considerations given they will be of direct relevance to the uptake of electric vehicles. These will include:

- the current and projected composition of transport fuels – liquid fuels; electricity; hydrogen
- vehicle fleet composition
- cross-border flow implications for electric vehicle (EV) uptake (including long distance haulage and buses)
- vehicle fleet age and turnover rates.

4.1.1.3 Carbon price

The base case makes no allowance for the consideration of a carbon price – it effectively assumes a carbon price of $0/tonne. A future carbon price could be included as a parameter in the scenario analysis if desired (including a possible date and implications arising from that date of future carbon pricing, particularly on the gas market).

4.2 Electricity modelling assumptions

The core assumptions used in the modelling of the electricity market are outlined in Table 3. Based on a review of the studies detailed above, a consensus view on each of the key assumptions was derived. The table identifies which of these assumptions have a major impact, a moderate impact, or a minimal impact on the outcomes from the market modelling.

Table 3 Core assumptions for electricity market modelling

Assumption	Basis for assumption
Assumptions that have a major impact on the outcomes	
Energy and greenhouse gas emission policies	- Retention of the Large-scale Renewable Energy Target (LRET) in its current form, Paris Agreement of 26-28 per cent reduction in GHG emissions below 2005 levels by 2030, State-based renewable energy targets as currently legislated and no national level emissions scheme implemented in projection horizon.
Electricity demand	- Underlying demand - AEMO 2021 Electricity Statement of Opportunities (ESOO) Central scenario - Rooftop PV - ACIL Allen's modelling of rooftop PV uptake - Behind the meter battery energy storage systems (BESS) - ACIL Allen's modelling of behind the meter BESS (linked to rooftop PV model) - Electric vehicles - AEMO 2021 ESOO Central scenario - ACIL Allen's charging profiles: a blend of three charging behaviours which change over time as charging infrastructure is developed. Includes an overnight charging profile, a daytime charging profile and a late evening/convenience charging profile. (To be adjusted for ACT Government analysis (Deloitte 2021) – see ACT specific assumptions below.) - Energy efficiency projections are based on AEMO modelling and reflect current trajectories.
Supply side	- NEM committed projects; closures and Snowy expansion
Gas price	- For the NEM: long-term prices to rise to levels between $10-12/GJ (real)
Coal costs	- Thermal coal converges to U$62/tonne in the long-term for new entrants
Representation of bidding behaviour	- In the NEM, contracted volume at short run marginal cost (SRMC) and uncontracted volume bid strategically or opportunistically
New entrant capital costs	- The capital cost of wind, solar and battery are falling faster than other generation technologies. Solar and storage are cheaper than wind and gas (CCGT) by 2030. Wind - $2,070/kW in 2021 - $1,780/kW in 2030 - $1,530/kW in 2040 - $1,445/kW in 2050

Assumption	Basis for assumption
	Solar (single axis tracking) - $1,435/kW in 2021 - $1,145/kW in 2030 - $960/kW in 2040 - $890/kW in 2050 Battery storage (four hours) - $1,745/kW in 2021 - $1,035/kW in 2030 - $885/kW in 2040 - $835/kW in 2050 Pumped hydro storage (eight hours) - $2,270/kW in 2021 - $2,235/kW in 2030 - $2,195/kW in 2040 - $2,160/kW in 2050
Short run marginal cost and emissions intensity for each generator	- SRMC estimated from historical price and dispatch outcomes; emission intensities from the National Greenhouse account factors published by the Commonwealth
Interconnectors	- ISP committed and actionable projects included: - Queensland-NSW Interconnector (QNI) minor (Sep 2022) - EnergyConnect (Jul 2024) - Heywood upgrade (Jul 2024) - Victoria-NSW Interconnector (VNI) Minor (Sep 2022) - VNI West (Jul 2026) - Marinus Link (two links: Jul 2028 and Jul 2032) - QNI Medium (Jul 2032)
Assumptions that have a moderate impact on the outcomes	
Modelling outcomes sought	- To provide insights for consumers and governments on the outlook of electricity market and emission projections - To understand retail bill impacts to customers and stakeholders of current climate change policies - To inform policy advice on specific fossil gas transition pathway options
Marginal loss factors (MLFs)	- ACIL Allen's projections of average annual MLFs by generator DUID, developed using commercial power flow software.
Renewable energy certificate modelling (demand and supply)	- 2020 Large-scale Renewable Energy Target has been met by committed capacity and is projected to be oversubscribed during the remainder of the scheme's life to 2030.

Assumption	Basis for assumption
Assumptions that have minimal impact on the outcomes	
Exchange rate **Consumer Price Index (CPI)**	- Market exchange rate: 0.75 AUD/USD - Treasury long term average target: 2.5% p.a.
Investments triggered in the transmission network	Investments triggered in the transmission network have not been considered in the analysis because the transmission network supplying the ACT also supplies all of New South Wales (NSW) and transmission augmentation costs are shared by all customers in ACT and NSW regardless of the location of the augmentation. As mentioned in Retail price impacts model changes in transmission costs in the retail price in electricity have been forecast using wholesale electricity modelling assumptions.
Source: ACIL Allen	

4.2.1 Retail price impacts model

The retail model brings together the following components:

- wholesale costs sourced from the wholesale electricity modelling (core assumptions in Table 3)
- renewable scheme costs – key inputs include published values for the LRET and Small-scale Renewable Energy Scheme (SRES) and ACIL Allen projections of the uptake of small-scale systems and Large-scale generation certificate (LGC) prices
- other costs including ancillary services costs and NEM fees – sourced from AEMO
- network costs including TransGrid transmission costs and Evoenergy distribution costs
- sourced from latest regulatory determinations and pricing proposals
- change in Evoenergy's Regulated asset base (RAB) sourced from the GHD network modelling
- change in TransGrid's RAB sourced from wholesale electricity modelling assumptions
- jurisdictional schemes – including projections of the Large Feed-in tariff (FiT) using the wholesale modelling outputs
- retail costs – benchmarked against regulator reports
- assumed energy consumption by customer type – based on the electricity demand forecast for the ACT
- the retail price outlook will be for a typical residential customer, low voltage (LV) business customer and a high voltage (HV) customer.

4.3 Gas projections

We outline the core assumptions used in developing the projections of the gas market and modelling to understand the impact on wholesale gas prices in Table 4.

Based on a review of the studies detailed in Section 4.1.1, a consensus view on each of the key assumptions was developed. The table identifies which of these assumptions have a major impact, a moderate impact, or a minimal impact on the projection/price outcomes.

Table 4 Core assumptions for gas market modelling

Assumption	Basis for assumption
Assumptions that have a major impact on the outcomes	
Oil price	- Market price - $US65/bbl
Total east coast gas demand	- Based on domestic gas demand and LNG exports from Queensland - Domestic demand for residential, commercial and industrial demand is based on AEMO's GSOO forecasts - GPG demand is based on projections for GPG use in the NEM estimated by ACIL Allen's *PowerMark* model - LNG exports in line with AEMO's GSOO forecasts
ACT gas demand	- Projection through to 2045 will be based on assumptions for: - Connection growth - Consumption split between residential, commercial and industrial segments - Consumption per connection for residential, commercial and industrial customers (and how this is expected to change) - How gas is used in ACT (assumptions on use in heating, hot water, cooking etc) - Changes in gas appliance efficiency - Seasonal and daily demand profiles to be based on data from AEMO and Evoenergy
Gas supply	- Source of gas production is primarily east coast; including coal seam methane from Queensland - Some gas from the Northern Territory is now linked into the east coast via the Northern Gas Pipeline
Gas transmission pipeline	- No upgrades on east coast
LNG import terminals	- One new LNG import terminal assumed – Port Kembla
Decarbonisation in other states	- Decarbonisation of gas networks in other states is not assumed to take place
Assumptions that have a moderate impact on the outcomes	
Modelling outcomes sought	- To understand broader market impacts from the ACT transitioning away from natural gas
Assumptions that have minimal impact on the outcomes	
Exchange rate	- Market exchange rate: 0.75 AUD/USD
CPI	- Treasury long term average target: 2.5% p.a.

Source: ACIL Allen

4.4 ACT specific assumptions

The core assumptions outlined above address whole-of-market (i.e., the NEM) issues and do not capture ACT specific considerations. The base case needs to consider the ACT's pathway to the phasing out of fossil-fuel gas by 2045 at the latest. However, there are several factors which impact on the realisation of this objective, such as:

- long-term industrial gas usage
- cross-border energy flows and infrastructure (i.e. the make-up of gas in the pipeline – natural gas/green gas – will be driven by the east coast market supply)
- ACT specific parameters.

There is an array of ACT Government policy commitments and strategies which impact on the base case parameters, or which need to be considered in the alternate scenarios modelled. The base case reflects the current and expected market trends, coupled with necessary adjustments to reflect specific ACT parameters and policy drawn from existing settings/announcements.

Appendix A details the key policies considered relevant to the market along with brief commentary as to their material impact and how they are incorporated into the assumptions below.

While the government's announced directions and proposed actions are considered in the modelling, these are not built into the base case unless concrete actions have been announced. For instance, while the intent to *'engage with the ZEV industry and adopt an ambitious target for new ACT vehicle sales to be zero emission by 2030*' is noted, this is not built into the base case projections given the outcome remains aspirational. However, many of these objectives will be considered in the framing of the alternate scenarios and policy actions which might be deployed to effectively deliver net zero emissions by 2045.

This issue is discussed further in Chapter 8 and Chapter 9.

4.4.1 Overarching demographics, economic development, urban developments, and policy considerations

Key overarching demographics, economic development, urban development, and policy considerations include:

- demographic and economic development settings/projections (economic/industry composition, regional development)
  - based on ACT Treasury figures
- the objective of phasing out fossil-fuel-gas in the ACT by 2045
- the continuing policy to purchase 100 per cent renewable electricity
  - a 2025 auction of an additional 400 MW (two x 200 MW wind farm) incorporated to effectively deliver this commitment
- options to consider carbon offsets, in particular the purchase of 100 per cent renewable electricity and/or 100 per cent green gas (hydrogen and/or biogas) as an option, plus the possibility of direct carbon offset purchases (national offsets are an option, but not international offsets) to address residual natural gas and liquid fuel usage (where alternatives are not feasible)

- implications of infrastructure developments for example, light rail, urban development (70:30 urban infill green-field development projections)
  - Stage 2 light rail adds 300 kW of average daily demand from 2025.
- full electrification of the Canberra hospital and Molonglo Commercial Centre
- climatic and weather projections.

4.4.2 Energy systems/technology

Key overarching energy systems and technology considerations include:

- no significant infrastructure upgrades to energy networks
- behavioral changes consistent with current trends – no significant step changes
- no significant new technologies adopted over next 10 years – technology remains as is/only considers change where commercial application is likely in next 10 years
- technology uptake (for example, roof top PV and behind the meter battery deployment) in line with current market trends
  - accounting for the ACT Sustainable Household Scheme and the impact on existing PV installation rates and on battery energy storage system rates
- EV uptake in line with 'conservative' EPSDD projections (as per the provided Deloitte analysis) – assume 28 per cent of sales are new ZEVs in 2030; ramping up in line with the Deloitte projections (applying an S curve, logistic function - slow ramp up, followed by acceleration and then maturation)
- 660MW of 'large-scale' battery storage distributed across the ACT in place by 2025 (includes exiting commitments factored into market - 250MW 'Big Canberra Battery' (BCB) plus other ACT battery commitments by GPG and Neoen – and additional Parliamentary and Governing Agreement (PAGA) commitments)
  - 110MW from 2023 (110MW auction batteries
  - 430MW from 2024 (300MW Neoen + 130MW BCB)
  - 120MW in 2025 (120MW BCB)
- pilot hydrogen vehicle fueling station in operation.

4.4.3 Increased electrification (including policy related to electricity and electric vehicles)

Considerations relating to acceleration of electrification include:

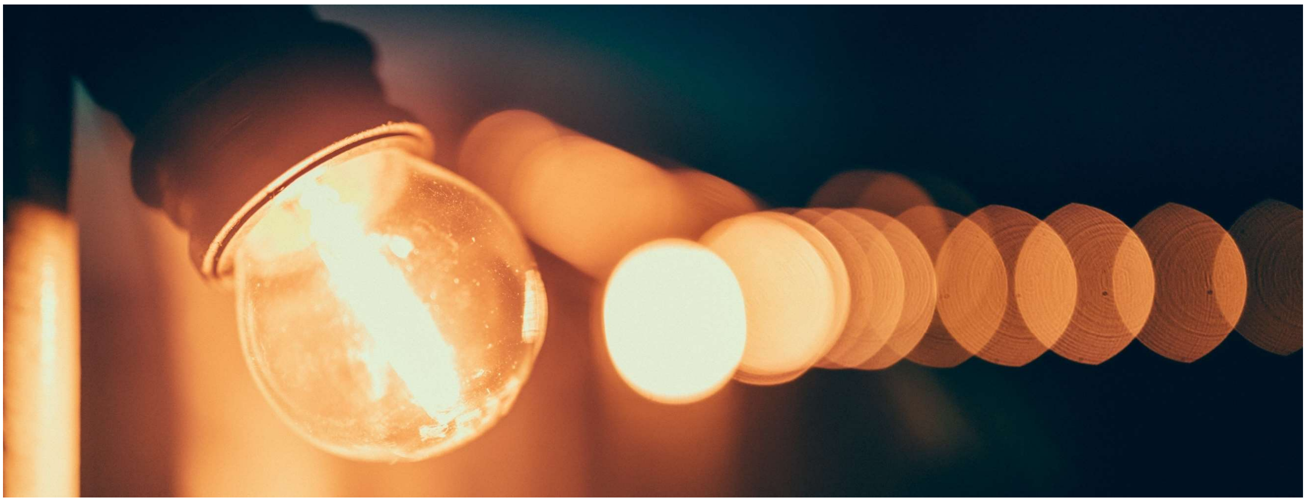
- market penetration by EVs in line with 'conservative' EPSDD projections (as per provided Deloitte analysis) – assume 28 per cent of sales are new ZEVs in 2030; ramp up in line with the Deloitte projections (will apply an S curve - logistic function – slow ramp up, followed by acceleration and then maturation)

- construction of 50 electric vehicle charging stations in 2022-23.
  - Deloitte projections have been used for growth in charging stations and electricity demand (as set out above)
- implementation of commitment to zero emissions public transport, garbage trucks, taxi and rideshare vehicles by 2035
  - 90 new electric buses to be introduced by 2024 followed by phased implementation (linear projection) of the remaining bus fleet from 2025 reaching 100 per cent in 2040 (the fleet currently consists of 450 buses with anticipated growth of 100 additional buses by 2030).
  - garbage trucks, taxi and rideshare vehicles not factored in (given private ownership and lack of specific incentives)
- demand side management/energy efficiency gains and incentives follow existing trends, derived from AEMO's modelling which considers existing policy and program initiatives.

4.4.4 Natural gas transition (including policy related to gas)

Natural gas transition considerations relating to the future role of gas in the energy system include:

- no gas connections in future stages of greenfield residential developments from 2021-22
- no new gas connections in infill developments from 2023
- new public housing stock to be fully electric and gradual conversion of existing public housing stock to fully electric (say over next 10 years)
  - this represents seven per cent of the ACT housing stock
- no (unforeseen) step changes in gas composition in line with southern NSW market expectations
  - noting hydrogen/biogas acceptable in meeting net zero emissions targets
  - noting long-term expectation that NSW should ultimately have sufficient biogas to meet ACT needs (which could be 'acquired' through auction)
- a declining contribution from natural gas to the energy mix in the future
- industrial consumers transition away from natural gas (where this is possible) in line with expected trends.



5. Gas market projections

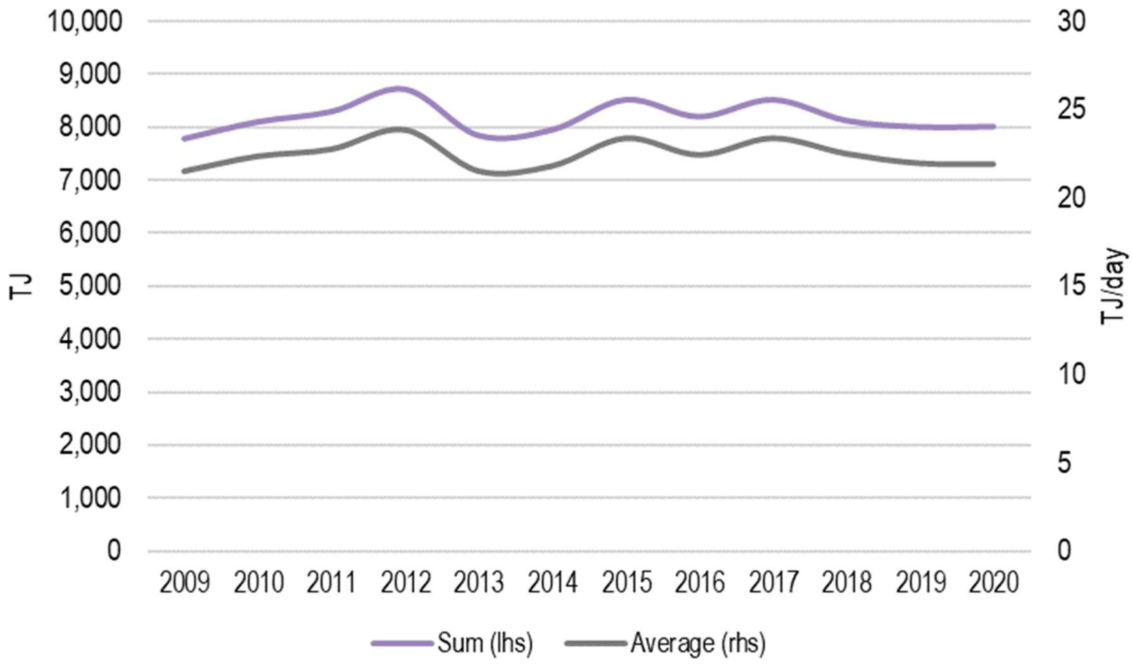
This Chapter provides a high-level projection on what gas demand might look like over the next few decades and consider the recent and expected trends in gas consumption across the ACT. The analysis provides for an understanding of the implications for the electricity network as the gas load is electrified.

5.1 ACT historical gas consumption

Evoenergy is the natural gas distributor that owns and operates gas infrastructure in the ACT and adjacent areas of NSW. Evoenergy provides natural gas to approximately 150 000 customers with its gas network, with the vast majority in the ACT and Queanbeyan.

The ACT and Queanbeyan regions consume around 8,000 TJ of natural gas per annum, as shown in Figure 7. On average, this equates to around 20 TJ/day. Of this 8,000 TJ, around 7,000 TJ is accounted for by the ACT. Consumption has been relatively stable over that period, with gas consumption predominantly coming from residential and commercial gas consumers. A small industrial segment also consumes natural gas, but this is relatively small compared to demand from the residential/commercial segment.

Figure 7 Annual gas consumption - ACT and Queanbeyan

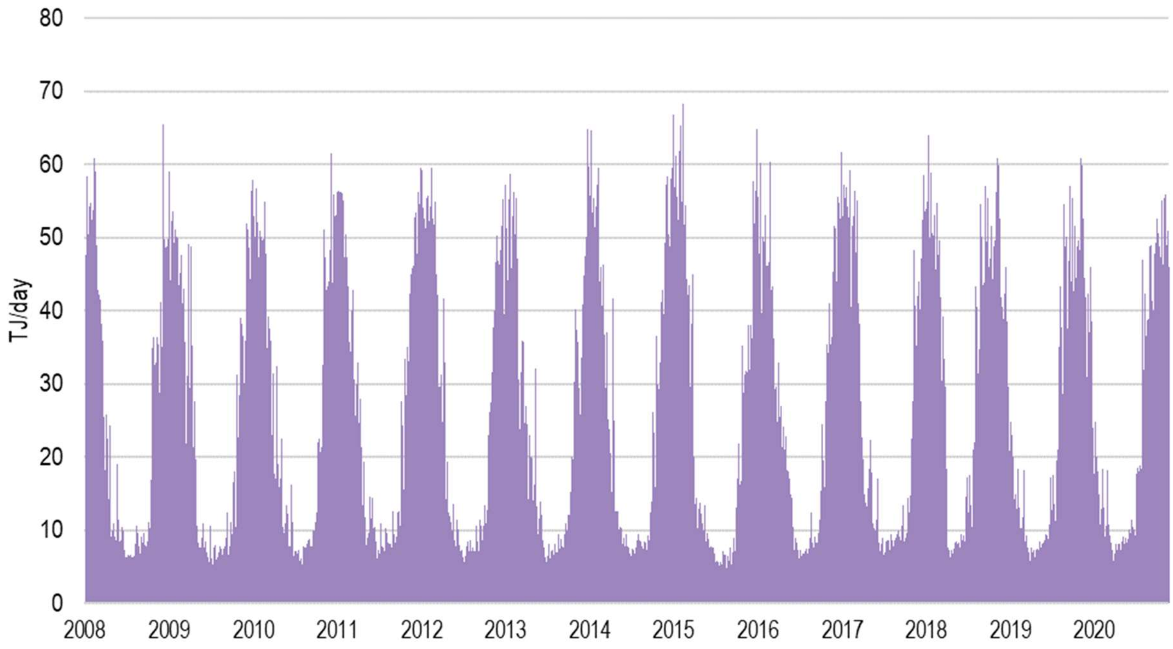


Source: ACIL Allen analysis of AEMO data

A key trait of this market is the seasonality of demand. Consumption in the ACT is very similar to the larger Victorian gas market, where most consumption occurs in the winter months. Winter consumption is on average around five to six times the consumption in summer as can be seen in Figure 8.

The key determinant of this is the very large consumption of gas in the cooler months used for heating. While gas is used for other purposes such as hot water and cooking appliances, heating is the primary use for gas customers in the ACT.

Figure 8 *Average monthly gas consumption - ACT and Queanbeyan*



Note: The horizontal axis starts mid 2008 (financial year mode)

Source: ACIL Allen analysis of AEMO data

While overall gas consumption has been relatively stable over the past decade, consumption has been steadily declining on a per connection basis. Usage per customer has been falling by over two per cent per annum since 2010. Total consumption therefore has been steady because of the rising number of connections during this period offsetting declining customer usage. If new connections were to cease, consumption in the ACT would be expected to decline.

Another notable trend is that peak consumption has been falling since 2015. Average peak monthly consumption in 2015 was around 70 TJ/day. However, this has fallen and in 2020 peak average monthly consumption was below 60 TJ/day. This trend is expected to continue – that is, falling customer usage and potentially improvements in efficiency leading to less heating consumption in the winter months.

5.1.1 Gas supply

The ACT is supplied via the Moomba to Sydney Pipeline and the Eastern Gas Pipeline. The Moomba to Sydney Pipeline (owned by APA Group) transports gas from the Cooper Basin via the Moomba processing plant (near the border of South Australia, Queensland, and NSW) and gas travelling to the southern states from Queensland.

Gas is also supplied to the ACT via the Eastern Gas Pipeline (owned by Jemena) which transports gas from large offshore basins off the coast of Victoria (predominantly from the Gippsland Basin in the Bass Strait). Supply on average, over the past decade has been split relatively evenly between both pipelines. However, it is expected that southern markets such as the ACT might be increasingly reliant on gas from Moomba, and especially Queensland in the future. This is due to declining gas supply becoming clear in recent years from the Bass Strait as gas reserves are depleted.

5.2 Gas demand methodology

A simple methodology has been used for projecting gas demand in the ACT over the period from 2022 to 2045 for this project. The methodology aims to provide a clear, high-level projection on what gas demand might look like over the next few decades and consider the recent and expected trends in gas consumption across the ACT. This projection will then be used to understand what this means for the electricity network as the gas load is electrified over time (under various scenarios). The methodology focuses on understanding trends in the:

- number of gas connections
- consumption per connection across all customer segments for example residential, commercial and industrial segments.

These two components will be projected forward over the period from 2022 to 2045. Key assumptions for each are highlighted below. Following the projection of these two components, a projection of total gas demand over the period from 2022 to 2045 can be undertaken.

In the base case, projections will be mainly determined by recent trends in gas consumption in the ACT over the past decade. The base case is a conservative projection and aligned to a scenario that reflects a 'status-quo' situation for the ACT gas market, considering announced Government policy.

Key assumptions that underpin the base case projection are:

- starting figures for connection numbers[3] and consumption are based on historical Evoenergy data
- consumption per connection projections based on expected trends as forecast in Evoenergy's latest access arrangement for the 2021-26 period
- new connections to be based on Evoenergy's latest access arrangement process
    - the key assumption is that no new connections are projected beyond 2023
- consumption split between residential, commercial, and industrial customers based on demand forecasts undertaken by the Centre for International Economics (CIE) in Evoenergy's latest access arrangement report
- we have estimated consumption split by appliance using data from the ABS, BIS Shrapnel and other industry sourced reports
- we have based consumption figures per appliance on research undertaken by Government bodies and figures provided by appliance manufacturers
- appliance numbers based on gas penetration rate and the assumption that each household connected to gas contains one unit of each appliance for example gas heater, hot water, cooktops and ovens.[4]

[3] The modelling is based on 'active' connections – it is noted that there are approximately 7,000 delivery points that are no longer being used (but have not been abolished).
[4] This is a simplistic assumption and no doubt over simplifies actual household appliance profiles. The alternative is constructing numerous different household profiles and looking to apply these. However, there is no guarantee that this will result in a more accurate outcome, in the absence of detailed surveying of individual households.

By estimating the appliance stock in the ACT, assumptions can be made about appliance switching rates (rates of switching from a gas appliance to another fuel type) over the projection period. This will be more important in the scenarios to come, which will be compared with the base case. To meet stricter emission targets, much higher switching rates will be required than in the base case.

Projected demand in the scenario options (following confirmation of the base case) will analyse in more detail what the primary drivers for consumption are for each consumer segment. In the base case, consumption per connection is expected to decline at the same rate for all segments in line with what is forecast under the latest access arrangement period.

This is a conservative approach. The scenarios will delve deeper into what reductions are needed for each consumer segment to meet more stringent emission targets.

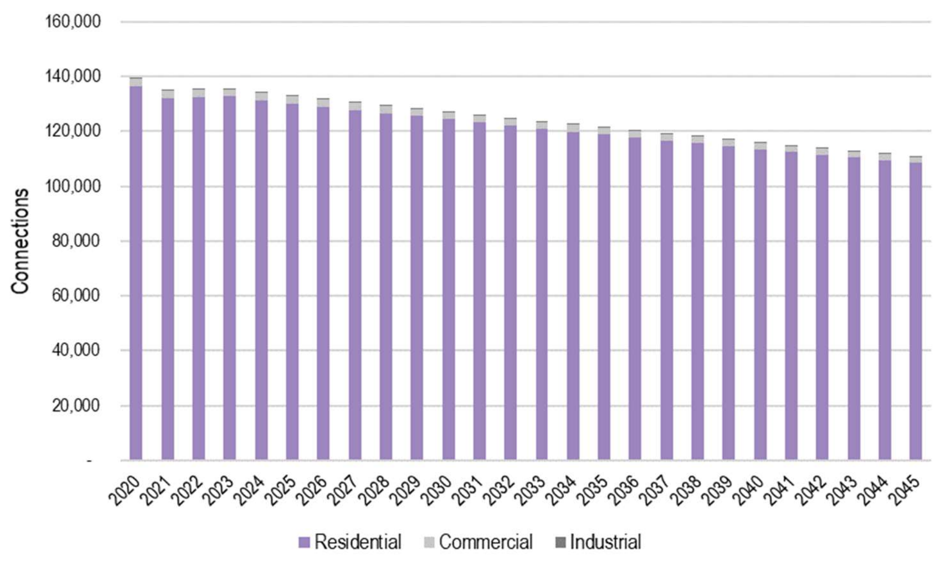
5.3 Base case gas projections

5.3.1 Connections

Projected gas connections in the ACT are provided at Figure 9. As mentioned above, the base case assumes connections will follow the trend in connections which is forecast in the latest access arrangement period. Gas connections over the period from 2021 to 2026 are forecast to trend lower by around one per cent per annum. To 2023, gas connections are expected to marginally increase but decline post 2023 as new connections effectively cease. We have assumed for the base case that this growth rate of minus one per cent per annum continues for the entire projection period.

Total connections in the ACT (excluding Queanbeyan) will drop from around 140,000 in 2020 to around 110,000 in 2045. This represents a total loss of 30,000 gas connections, or a 21 per cent decline in connections from current levels.

Figure 9 Projected gas connections - ACT



Source: ACIL Allen

5.3.2 Consumption per connection

We project consumption per connection in the base case to decline by approximately 2.5 per cent per annum. This rate is slightly higher than what has been the case over the past 10 to 15 years, which has been around two per cent per annum. We based this rate of decline in consumption on forecasts over the next access arrangement period and a small improvement in building efficiency.

5.3.3 Residential

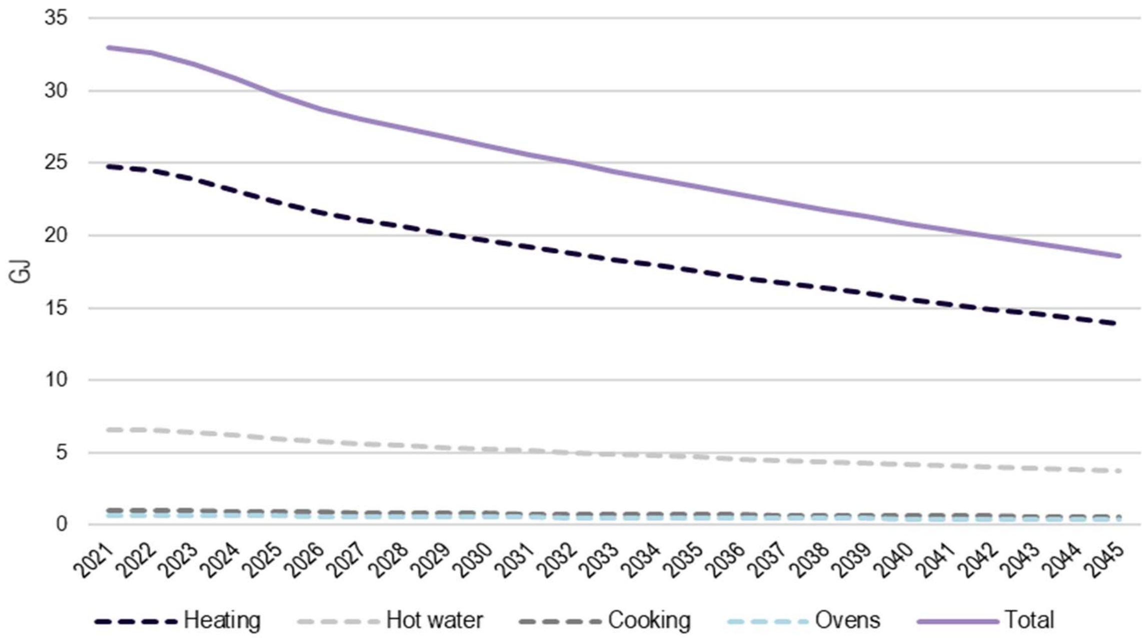
Residential consumption per connection is expected to drop from levels around 33 GJ per annum to 19 GJ per annum in the base case. This means residential gas consumers are projected to consume around 40 per cent less than they currently do by 2045.

Most of the residential gas consumption is for heating, which accounts for approximately 75 per cent of household consumption. Hot water is next, representing around 20 per cent of consumption, followed by small amounts for cooking and ovens.

Further improvements in efficiency of individual appliances are possible over the period to 2045, as well as improvements building efficiency (noting that the technical limitations of gas appliance efficiency are closing which will limit future trends[5]). However, the base case has considered no further improvements in efficiencies beyond what is expected over the next few years.

Projected residential consumption per connection is illustrated at Figure 10.

Figure 10 ***Projected gas consumption – per residential connection, by appliance type***



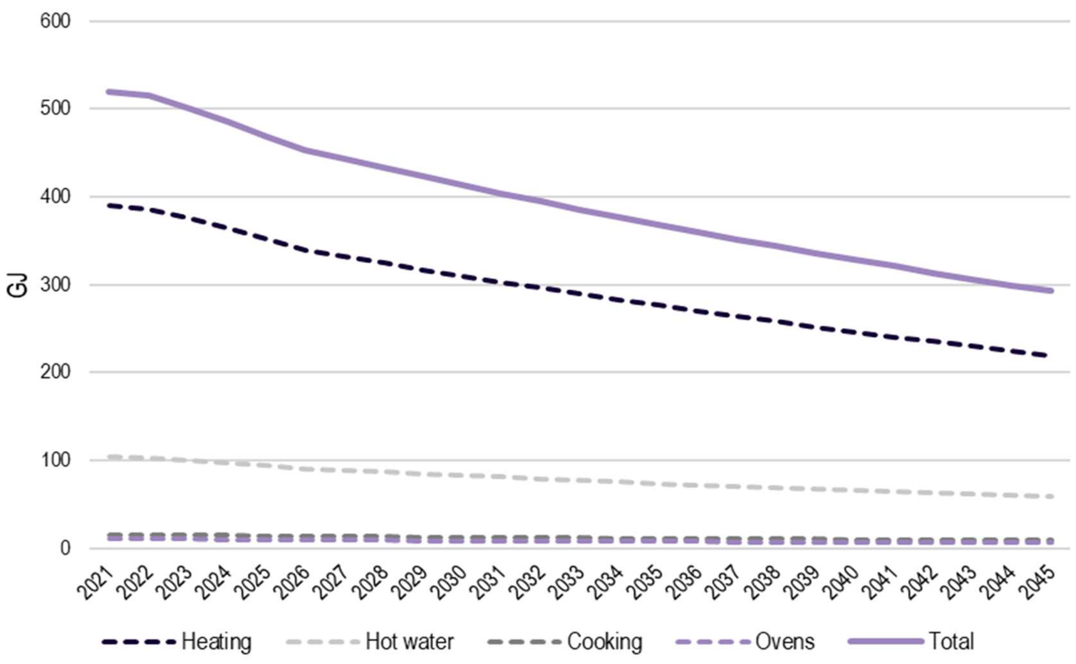
Source: ACIL Allen

[5] Many European gas boilers now have efficiency ratings in excess of 90 per cent – see **https://boilerhut.co.uk/boiler-guides/most-efficient-boilers/** accessed 26 November 2021

5.3.4 Commercial

Commercial consumption per connection is expected to trend down at the same rate as residential customers. It has been assumed most commercial consumers are small businesses and shops. Therefore, the same split between appliance use is used and heating is the primary use of gas in commercial connections. Consumption per connection is assumed to drop from levels around 500 GJ per annum to levels around 200 GJ per annum in 2045, representing a 40 per cent decline in consumption as indicated at Figure 11. Once again, a conservative estimate has been made for the base case. In the modelling of the scenarios, an assessment of what drivers might reduce commercial consumption more than predicted in the base case will be completed.

Figure 11 ***Projected gas consumption – per commercial connection, by appliance***



Source: ACIL Allen

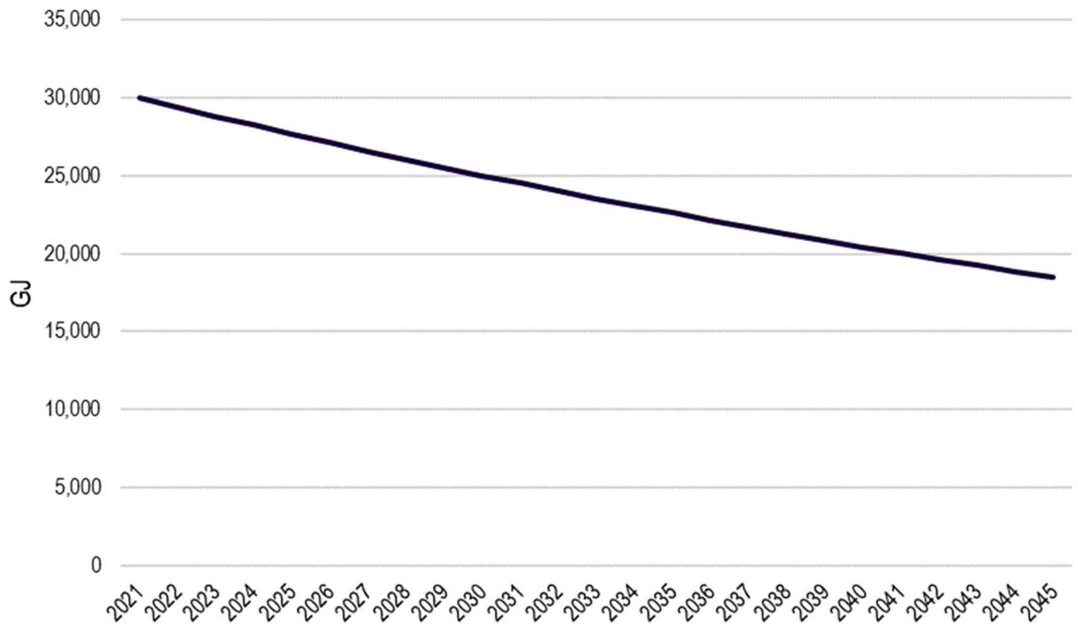
5.3.5 Industrial

Industrial gas consumption represents the smallest segment in the ACT. However, gas consumers in this segment are much larger users of gas than residential and commercial users. Approximately 40 gas users are classified as industrial users in the ACT. These users consume, on average, approximately 30,000 GJ per annum each.

Although no specific information is available to identify these customers, its likely they relate to concrete producers, glass manufacturers, and large commercial buildings, for example universities, hospitals etc. ACIL Allen has estimated that consumption for industrial users will decline over the projection period to the same extent as the mass residential/commercial market. However, reducing gas consumption is likely to be more difficult for large industrial users, as some will use gas a feedstock. We will further analyse this in the scenarios. Figure 12 illustrates ACIL Allen’s projection for industrial consumption per connection out to 2045.

Consumption is expected to drop from around 30,000 GJ per annum to levels just under 20,000 GJ per annum. Although this could be considered a significant drop, we expect a number of significant industrial users could transition away from natural gas, for example those large commercial users classified as industrial users.

Figure 12 Projected gas consumption – per industrial connection

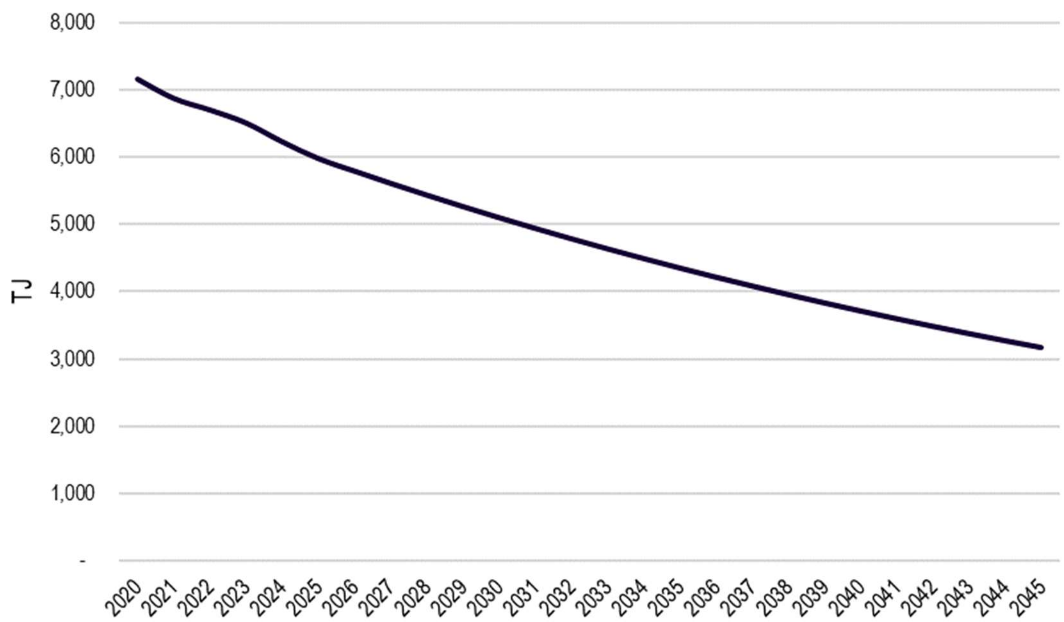


Source: ACIL Allen

5.3.6 Projected total consumption

The base case projects total consumption in the ACT to drop from levels around 7,000 TJ currently to around 3,000 TJ by 2045. This represents a decline of approximately 60 per cent. Most of the decline is from falling consumption per connection, but also from a steady decline in connections from 2023. This represents an overall steady decline, but is a marked change from consumption over the past decade (which has been relatively stable). Total projected consumption out to 2045 is illustrated in Figure 13.

Figure 13 Projected total gas consumption - ACT

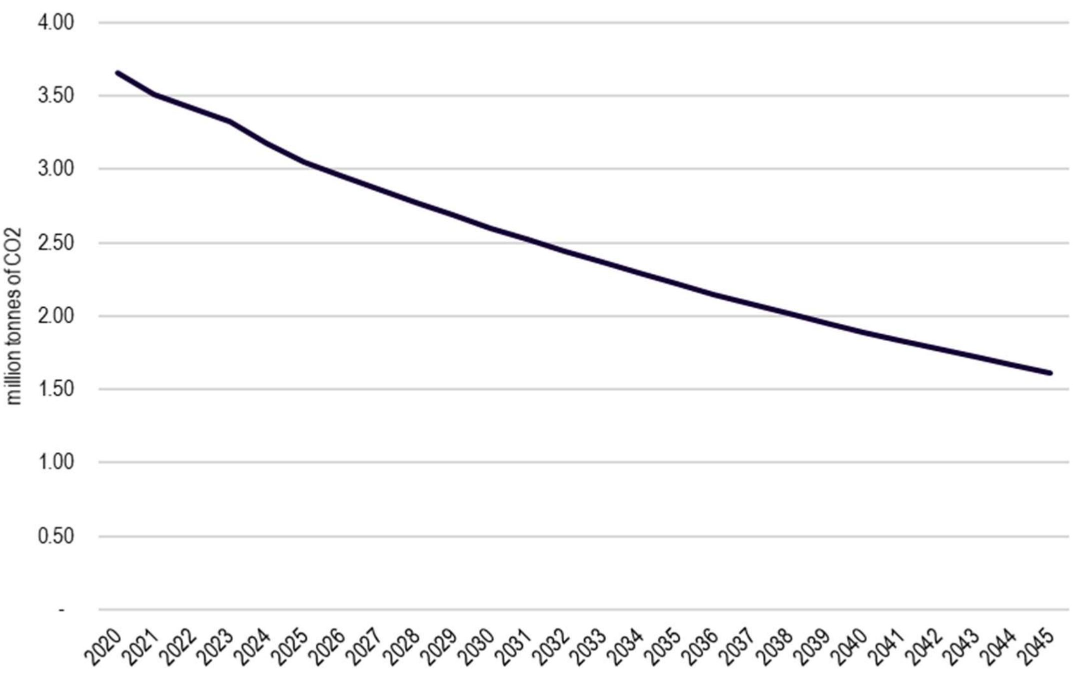


Source: ACIL Allen

5.3.7 Emissions

In line with projected gas consumption, emissions from the consumption of natural gas in the ACT are expected to fall. Estimated emissions are currently around 3.5 million tonnes per annum of CO_2. This would reduce to levels around 1.5 million tonnes per annum by 2045 under the base case (representing a 57 per cent reduction in emissions). Emissions are presented below in Figure 14.

Figure 14 Natural gas projected emissions



Source: ACIL Allen

5.4 Implications of demand forecasts

There are a range of implications over the projection period as gas consumption in the ACT declines. This report summarises (at a high level) some key implications for the gas industry, Government, and gas consumers.

5.4.1 Gas pricing: wholesale prices

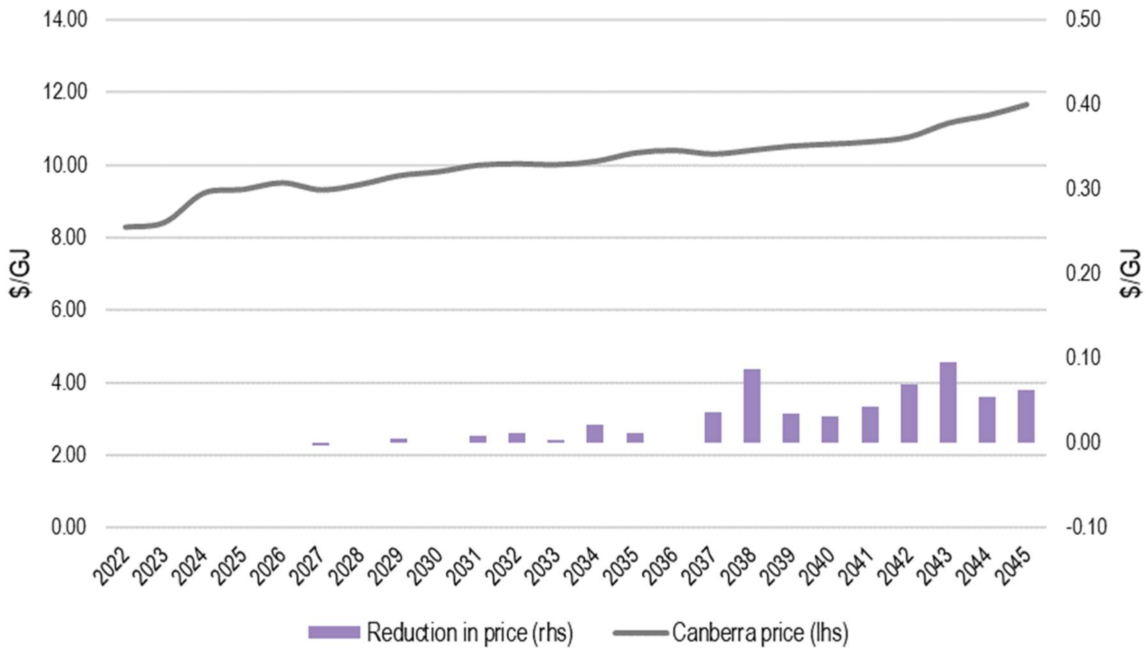
Wholesale gas prices are not expected to significantly change over the projection period. Even though gas demand in the ACT is expected to decline by around 2.5 per cent per annum in the base case, the impact on wholesale prices across the east coast market will be negligible.

The projected reduction in demand in the ACT and the magnitude of the ACT's consumption, compared to the entire east coast gas market, means wholesale prices will change by less than one per cent per annum in the 2030s and 2040s. For example, the ACT's gas consumption of around seven PJ per year represents approximately 1.5 per cent of total east coast gas consumption.

The base case scenario also assumes that decarbonisation does not occur in other states in eastern Australia. Gas is expected to remain a large source of energy over the projection period. Therefore, wholesale gas prices are not expected to decline over the projection period. However, it is noted that both Victoria and NSW are examining options for greening the east coast gas market including blending a percentage of green gas into existing networks (for example, Victoria's Gas Substitution Roadmap; NSW Hydrogen Strategy). Whether or not, and the extent to which this may impact wholesale prices is a matter of conjecture and will depend on a range of variables, addressed in Section 5.6 below.

Figure 15 presents the projection for wholesale gas prices in the ACT over the projection period. This figure also shows the difference in the wholesale price in the base case scenario compared with a scenario where ACT gas consumption remains flat over the projection period, instead of declining as projected (represented by the purple bars which show wholesale prices will not change meaningfully as ACT reduces its gas consumption over time). This shows that the decline in ACT consumption is not expected to alter wholesale prices significantly over the projection period (although to the extent there are any impacts on the wholesale gas price, they are negative).

Figure 15 ***Projected wholesale prices in the ACT***



Source: ACIL Allen

5.4.2 Gas pricing: retail prices

Retail prices represent the price paid ultimately by a consumer of gas who receives gas via a retailer. For example, gas received by a residential customer, commercial business customer and sometimes an industrial customer. Some industrial customers may receive gas via a direct contract with a gas producer and not receive gas via a retailer.

Retail prices typically comprise the following components:

- wholesale
- transmission
- distribution
- retail.

Sometimes retail prices may also incorporate some other category of cost, such as inclusion of costs related to environmental factors.

For this report, high level estimates of where retail prices are expected to trend over the projection period have been made. A key assumption is that the network remains viable over this period and the regulator of the network, the Australian Energy Regulator (AER), allows Evoenergy to increase its tariff to compensate for declining revenues as a result of declining gas consumption. We have undertaken the analysis in this way to show how tariffs would need to increase to compensate for the levels of declining gas consumption expected. It shows the expected pressures on the network.

Further analysis is provided in the **Strategic Report** where this assumption is used differently in the 'tipping point' analysis. For example, if revenues are expected to be tightly regulated by the AER, the impact on the network will be increasingly negative in terms of revenue generation.

5.4.2.1 Transmission

We have assumed transmission costs will increase by CPI over the projection period. Transmission is a relatively small component of the overall delivered cost of gas to a consumer. The ACT receives gas mainly from offshore fields in the Gippsland Basin off the coast of Victoria, and from Queensland and South Australia. On average, over the past decade, around half of the Territory's supply comes from southern sources (for example Gippsland Basin) and the other half from northern sources (Queensland and South Australia).

The transmission cost is an average of the total transmission pipeline cost of sourcing gas from these sources and delivering it to the ACT. Current transmission costs for the Eastern Gas Pipeline (EGP) are around $1.30/GJ to deliver gas from the Longford production facility to the Evoenergy distribution network. Gas from Queensland costs around $2.50/GJ according to current published tariffs by APA.

On average, the cost of transmission works out to be around 0.6 cents/MJ. This represents around 15 per cent of the total retail delivered price. Over the projection period we expect the cost of transmission to rise, as mentioned above by CPI only. A key assumption is that these pipelines delivering gas to the ACT are not subject to any capital works or expansionary projects. If this were to occur, transmission tariffs could be adjusted. However, we have assumed for this study that these pipelines remain in the same operating conditions and specifications as is the case currently.

5.4.2.2 Distribution

Distribution charges typically represent the largest component of the retail delivered price in most states. The key drivers of distribution charges are the cost of installing and maintaining the network of various pipes and connections. Distribution networks seek to recover these costs using two-part tariffs with a variable component, which charges per MJ of gas consumed, and a fixed component. Distribution networks charge these tariffs to retailers, who pass them through to residential customers, and the structure of distribution charges usually determines a retailer's pricing structure.

Distribution networks rely on economies of scale and volume throughput to minimise prices and make gas use attractive. This is a function of the number of customers connected to a network and the consumption of each customer.

Evoenergy's distribution tariff over the past decade has hovered generally between 0.8 cents/MJ and 1.3 cents/MJ. Any change has often been due to the impact of physical works to the network. ACIL Allen has estimated a distribution tariff using the AER's pricing model that is publicly accessible. ACIL Allen estimated a tariff for the distribution network of around 1.0 cent/MJ in 2022. This is based on various assumptions surrounding:

- operating and network capital costs
- depreciation rates (in line with depreciation rates allowed under current access arrangements)
- weighted average cost of capital (WACC) rate
- return on capital
- inflation rate
- forecast energy load (gas consumed through the network).

Over the projection period, we expect the distribution tariff to increase significantly as the level of gas consumption declines. Our analysis suggests the tariff would likely increase from 1.0 cent/MJ to levels around 1.45 cents/MJ by the early to mid-2030s. This again assumes the AER would allow Evoenergy to pass through higher tariffs to compensate for declining gas consumption and to ensure sufficient revenues for the operation of the network. In real terms, revenue generation (unsmoothed) increases by around 2.2 per cent per year to the mid-2030s (in line with AER expectations over the next access arrangement period).

If the AER were to disallow Evoenergy from passing on higher tariffs, this would have material implications for revenue generation.

5.4.2.3 Retail cost component

The retail cost component of a consumer's residential bill covers a retailer's operation and marketing costs. It also includes any retailer profit margin. A retailer's profit margin depends on the retailer's ability to operate efficiently, the level of competition in the market and whether there is a regulated ceiling on the tariffs consumers can be charged.

Typically, in the ACT, the retail component of the retail price has fluctuated in recent years from levels around 0.5 cents/MJ to levels near 1.0 cent/MJ. ACIL Allen assumed the retail component for this study to be around 0.7 cents/MJ, representing around 20 per cent of the total retail delivered price. This component has only been increased by CPI.

We have made no other adjustment as this historically can move around according to several factors which are difficult to model and project.

Total retail price

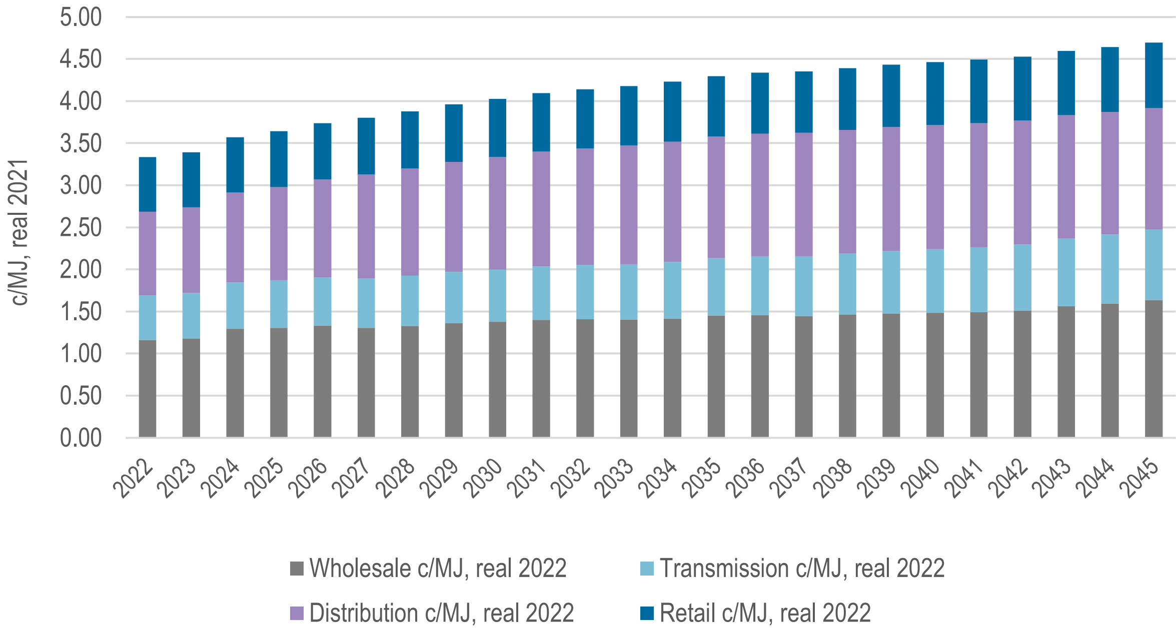
The total delivered retail price projected over the projection period is presented below in Figure 16.

The price increases in real terms from levels around 3.3 cents/MJ to levels around 4.5 cents/MJ by the mid-2040s. This means for a household consuming around 35 GJ per annum[6], their residential gas bill would increase from around $1,155 per annum to $1,645 per annum (around a 40 per cent increase, primarily in the

[6] Frontier Economics: Residential energy consumption benchmarks - Final report for the Australian Energy Regulator | 9 December 2020

earlier years of transition). The retail price noticeably increases over the first 10 to 15 years (until the mid-2030s) of the projection period, as the distribution component increases as consumption volumes decline and wholesale prices increase. However, the significant driver of the increase is the projected increase in distribution tariffs.

Figure 16 ***ACT retail price for gas delivered to residential customers***



Source: ACIL Allen

5.5 Investment in the gas network

Another key implication of declining demand is focused on future investment and maintenance of the Evoenergy gas network. The pathway to the 2045 decarbonisation target is not yet clear, but it could involve switching to electricity for some existing gas consumers and/or introducing hydrogen or biogas as a supplement to or replacement of natural gas.

Both pathways involve reductions in the demand for natural gas over the two to three decades, weakening incentives to invest in the natural-gas sector. Moreover, the prospect of electrification scenarios creates uncertainty for owners of gas infrastructure assets in relation to the length of time that they will have to recover the costs of any investment required to ensure security and reliability of supply in the short-medium term.

In the base case, the demand for natural gas faces a steady decline over the projection period, with a 60 per cent reduction in gas consumption by 2045. This potentially places pressure on the distribution network in terms of its long-term viability and will have consequences for gas prices. What this means for gas networks and the current regulatory regime will need to be front and centre, particularly for the more stringent scenarios where deeper cuts for natural gas are expected and the transition to electrification is accelerated.

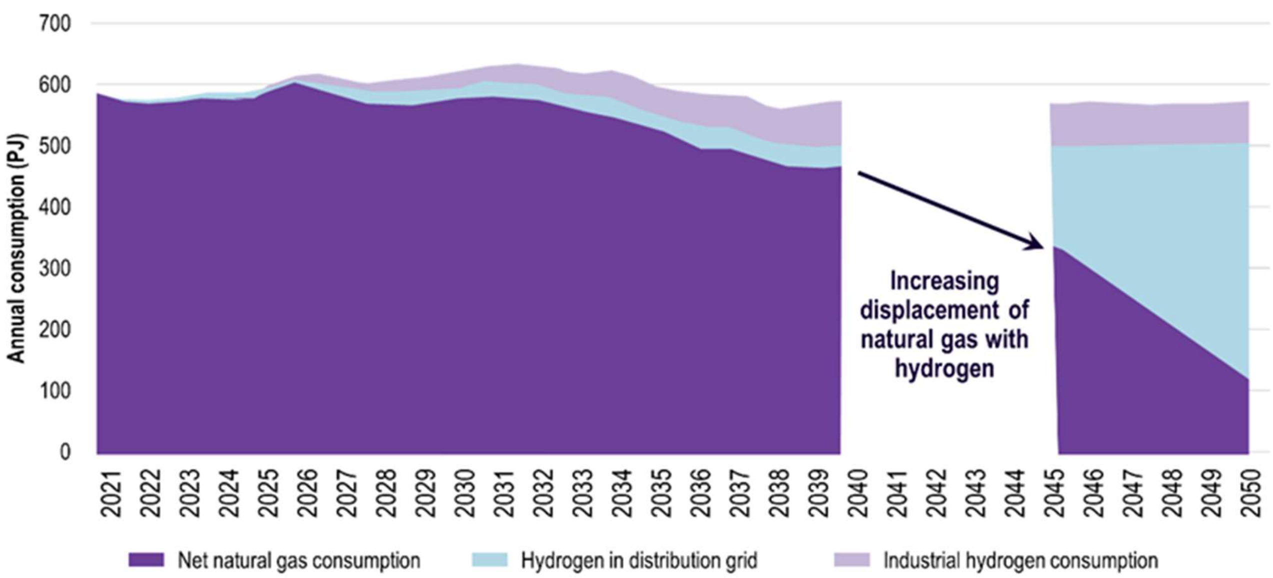
We understand that the AER is currently reviewing implications that the shortening of asset life might have for regulatory parameters such as depreciation schedules. Depreciation and asset lives is expected to become a focal point for gas networks as gas consumption declines. ACIL Allen expects allowable depreciation rates to move higher as decarbonisation plans are laid out across eastern Australia over the next few years.

Depending on how the AER and the regulatory regime issues are addressed, this will have important implications for how Evoenergy may operate the network. If the ability to increase revenue over the next few years is not to the level to allow sufficient returns, the long-term plans for the network and investment might change. The AER review is not expected to be completed until the end of 2021. However, its findings will be important to addressing investment in regulated gas infrastructure in the face of an ultimate removal of natural gas from the energy mix in the ACT and more broadly, eastern Australia.

5.6 Role of hydrogen

Hydrogen is gaining momentum as a pathway to lower emissions. For example, in the ‘Hydrogen’ scenario in its 2021 Gas Statement of Opportunities, AEMO projects that hydrogen could replace up to 20 per cent of the domestic natural-gas demand by 2040, with more significant contributions possible after 2040 as illustrated at Figure 17.

Figure 17 AEMO assumed hydrogen impact on natural gas consumption 2021-2050



Source: AEMO, 2021 Gas Statement of Opportunities Report

While there may be a long-term opportunity for hydrogen to replace domestic natural gas consumption, it is anticipated that the industrial and commercial sectors will be the areas of focus in the first instance. Positively, hydrogen is gaining increasing attention from industry and governments across Australia with gas distribution companies in Australia considering the option of hydrogen blending, with several undertaking pilot projects (i.e. Jemena and Australian Gas Networks in Sydney and Adelaide operations, respectively). Although considerable research and evaluation is required, it is likely that hydrogen could play a role in Australia’s energy mix in the long term. For the moment, national hydrogen strategies are primarily focused on large-scale industrial applications and export opportunities, and as such the ACT presents limited potential.

The viability of introducing hydrogen into gas networks to any significant extent is limited by technological, network and cost barriers, coupled with the availability and commercial development of appropriate appliances. Consumer conversion costs (in relation to both appliances and the property based plumbing costs) will be an important transition factor. Transitioning to hydrogen would incur higher costs, but these would be expected decline overtime.

However, hydrogen faces some steep challenges before this is a realistic opportunity (for either the ACT or more generally). These mainly relate to the cost of producing and transporting hydrogen, and the technical challenges of injecting hydrogen into existing natural gas networks. For example, injecting hydrogen to convert mass market customers (residential and small business) is still highly unlikely based on current hydrogen production costs and the considerable costs to convert natural gas users to hydrogen ready infrastructure and appliances.

The ACT could be a research and development case study for hydrogen development in the future given the size and specifications of the Evoenergy network. Smaller networks are likely to be the first examples of how hydrogen could be injected into existing natural gas networks and further developed.

Biogas is also another form of green gas that has can assist with decarbonising economies. However, it does face some of its own unique challenges and some which are comparable with hydrogen. For example, biogas is still relatively expensive to produce and feedstock is limited.[7] The biogas industry will need to overcome these challenges to become a genuine alternative that can replace some of the ACT's reliance on natural gas.

5.6.1 Costs of hydrogen development

Currently, green hydrogen is expensive compared to natural gas. The wholesale price of green hydrogen is expected to be:

- around $16/GJ to $24/GJ by 2030
- around $13GJ to $22.5/GJ by 2040
- around $10.0/GJ to $17/GJ by 2050.[8]

These costs also do not account for the significant additional costs for storing and transporting hydrogen. It also does not take into account the differing energy density between hydrogen and natural gas. For example, it takes about 3 cubic feet of hydrogen to deliver the same energy as 1 cubic foot of natural gas.[9]

Natural gas prices are currently projected to be between $8/GJ and $10/GJ. However, ACIL Allen's gas market projections suggest that prices could rise to around $12/GJ by 2040 under some supply scenarios.

Green hydrogen is likely to be the preferred method of hydrogen production in Australia, if it were to be developed on a large scale. This offers a 'green' pathway for producing hydrogen based on renewable power. Other forms of hydrogen production, like grey hydrogen or blue hydrogen, are unlikely to be favoured in the medium to long-term, given their emission profiles.

[7] Enea Consulting: Biogas Opportunities for Australia, March 2019
[8] Advisian: "Australian hydrogen market study" 24 May 2021
[9] Ulf Bossel and Baldur Eliasson - Energy and the Hydrogen Economy, available at https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf

5.6.2 Technical challenges

Blending hydrogen and/or biogas into the existing natural gas distribution network at low concentrations, less than 20 per cent by volume, is generally considered viable without significantly increasing risks associated with utilisation, overall public safety, or the durability and integrity of the existing natural gas pipeline network. Blending up to 10 per cent is readily achieved, with up to 20 per cent hydrogen by volume feasible, given it does not affect the Wobbe index. However, some modifications of the supporting pipeline gas specification may be required. A number of companies across Australia are undertaking pilot blending projects. There are no limits to the volumes of biomethane[10] that can be substituted.

A review into hydrogen in gas distribution networks was undertaken in 2019 under the National Hydrogen Strategy (endorsed by the then COAG Energy Council). The review found that the addition of up to 10 per cent hydrogen (by volume) in the natural-gas distribution networks is not expected to have significant impacts for the applicable Australian standards, but that a review of Australian standards applicable to downstream installations and appliances should also be completed to enable upscale of hydrogen injection into the gas distribution networks.[11]

Longer term, higher levels of hydrogen displacement of natural gas could occur, but this would likely mean greater investment/augmentation of household appliances (and to consumer piping) to cater to hydrogen and, potentially greater investment in transmission/distribution pipeline infrastructure to address technical issues.

Hydrogen blending concentrations above 50 per cent are not currently considered feasible in existing distribution networks due to increased impact on safety, leakage, and material integrity. Adding more than 50 per cent hydrogen to a distribution pipeline yields a significant increase in overall risk due and increases the probability and severity of ignition and explosion scenarios.[12] The only feasible alternative to reach blending concentrations above 50 per cent is to construct a dedicated hydrogen network or revamp the existing national infrastructure.

Advisian, which produced a report on the potential hydrogen market for the Commonwealth Government earlier this year, suggested that for blended hydrogen in natural gas networks beyond levels compatible with existing appliances and infrastructure to be viable[13]:

- conversion costs of infrastructure and appliances must not be prohibitive
- electrification options are not able to supply similar services at competitive prices
- the gas network provides significant and valuable energy storage to support renewable electricity deployment.

A key potential advantage for the ACT is if hydrogen can be developed close to the Evoenergy network and not have to travel via high pressure transmission pipelines. Producing hydrogen in close proximity to the network via electrolysers and injecting hydrogen directly into the distribution network is likely to be an easier pathway for hydrogen development and a lower cost pathway (by avoiding transportation via transmission pipelines). Of the three factors above, it is difficult to see the first two points being met in the ACT.

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[10] Raw biogas typically contains approximately 30-45% of CO_2, H_2S, water and other impurities. There are a range of biogas conversion technologies to produce biomethane which can be used as a natural gas LNG replacement.
[11] COAG Energy Council (2019) Hydrogen in the gas distribution networks, Commonwealth of Australia
[12] Advisian: "Australian hydrogen market study" 24 May 2021
[13] Advisian: "Australian hydrogen market study" 24 May 2021

However, although there is a possibility hydrogen could play a role in the ACT, the ACT is still likely to require significant supplies of natural gas for the next 10 to 20 years. The timeline to widescale uptake of hydrogen is likely to be heavily influenced by the progress with pilot projects and the outcomes from a commercial and technical point of view. If early pilot projects are successful, and continued investment in the technology brings down hydrogen costs, hydrogen may well have a large role in decades to come. However, until these types of projects are completed, the timelines for hydrogen remain uncertain.

There may be opportunities to develop 'mini' hydrogen networks supplying localised agglomerations of key industrial users. This may enable the reuse of parts of the existing ACT gas network.

5.7 Consumer conversion costs

An important factor in how quickly consumers will transition away from natural gas to electrification, or possibly hydrogen in the long term, is the cost of converting appliances. When consumers will convert is another important question. The time when consumers are likely to convert is when the appliance reaches the end of its useful life (often when warranties expire). Appliances have a life span of around 10 to 15 years. Assuming appliances have a life span of 15 years, this means around seven per cent of the total gas appliance stock needs to be replaced each year to transition all gas consumers off natural gas by 2045.

In the base case the rate of gas consumers converting to electrification is between two and three per cent. Therefore, the analysis suggests that when it comes to replacing gas appliances as they expire, less than half of the eligible gas appliance stock each year is replaced with electric appliances in the base case (i.e., in the base case many gas consumers opt to retain gas and replace appliances with new gas appliances when required). In the more aggressive scenarios, where a stronger transition away from gas occurs, the rate (of change from gas to electric appliances) is expected to be much higher.

The costs of conversion are likely to be a major contributor to this decision and the costs of running electric appliances year-round. A previous report by ACIL Allen investigated this issue by analysing whether a small sample of households (representing different consumer profiles) would be better off financially from switching from natural gas to electrical appliances (over a 15-year period).[14]

The study's overall conclusion was that switching to electrical appliances was beneficial from a financial point of view (especially if households combined solar power with their electrical appliances). Figure 18 and Figure 19 below demonstrates the savings these different households could generate from switching to electrical appliances (whether combined with solar or not).

Further analysis from Sustainability Victoria suggests the costs of heating, hot water and cooking using electrical appliances is cheaper than gas appliances.[15] A significant reason for this is because the improvements in efficiency in electric appliances progresses at a faster rate than gas appliances.

The cost of running electric appliances is likely to be the key differentiating factor to persuade consumers to switch. In terms of the cost of purchasing gas appliances versus electric appliances and the cost of installation, the difference appears to be relatively minimal at this stage. No significant expense outside of replacing appliances is likely to be required.

[14] ACIL Allen: Household energy choice in the ACT - modelling and analysis, November 2020
[15] Sustainability Victoria: Home heating costs comparison - https://www.sustainability.vic.gov.au/energy-efficiency-and-reducing-emissions/save-energy-in-the-home/reduce-heating-costs-at-home/calculate-heating-costs

However, transitioning to hydrogen would incur much higher costs. Besides replacing natural gas appliances with hydrogen compatible appliances, other costs that are likely to be incurred include:

- new gas meter (estimated to be around $300-$500)
- new gas line from meter to house (estimated to cost between $1,000 to $3,000)
- potentially new gas lines through the house (which would cost a further $5,000 to $10,000).

Overtime these costs will decline, but transitioning to large scale hydrogen (beyond blends such as 10 per cent) will mean significant costs to convert gas connected properties to hydrogen only.

Figure 18 ***Financial savings from converting to electrical appliances (combined with solar)***

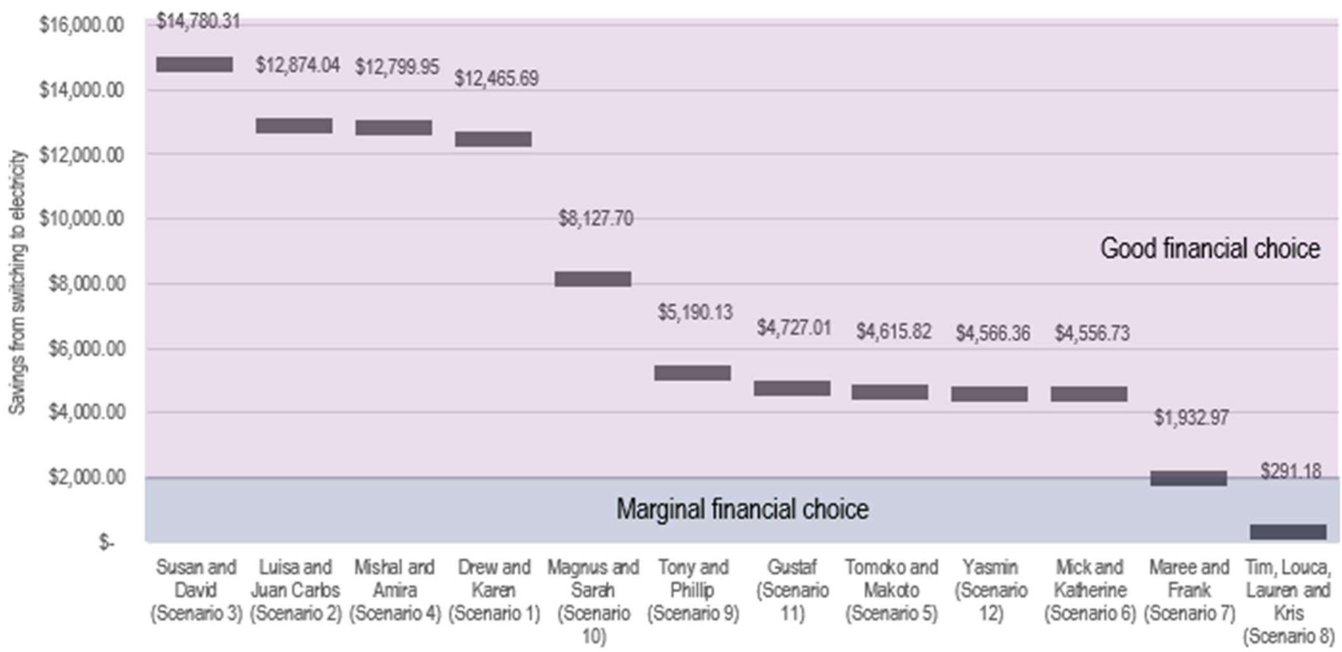
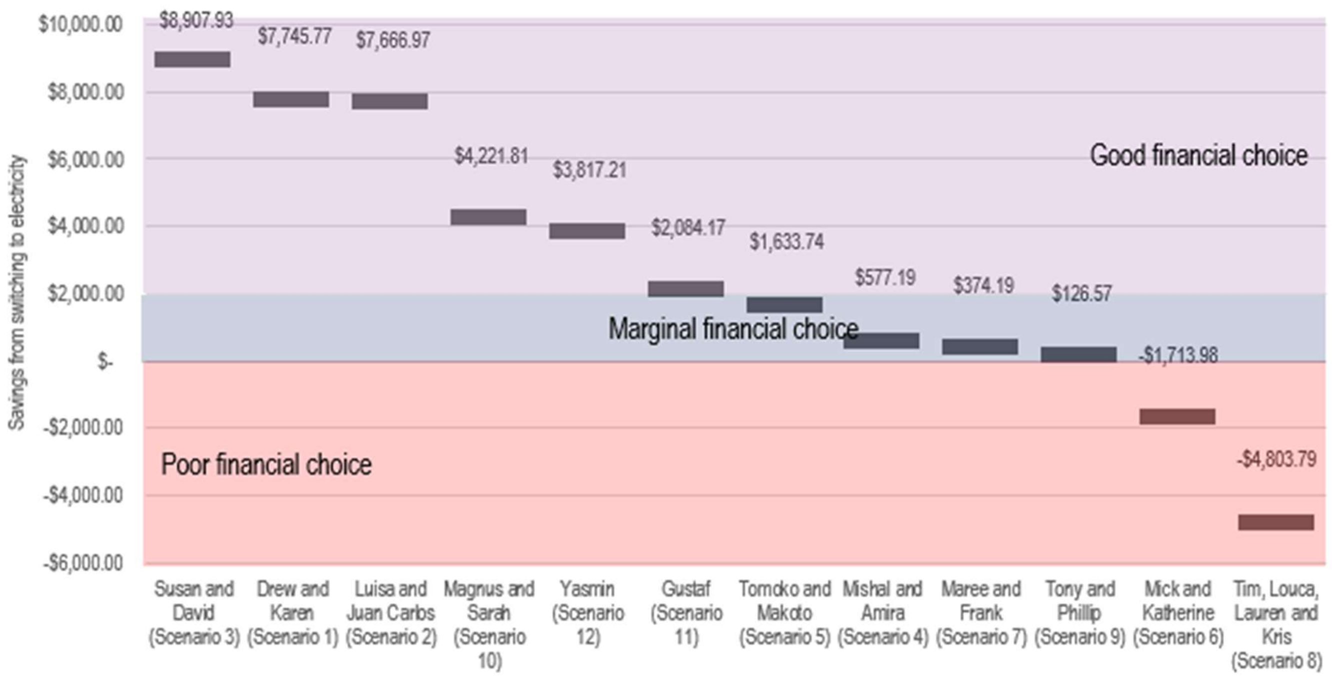


Figure 19 ***Financial savings from converting to electrical appliances (not combined with solar)***



6. Electricity market modelling

This Chapter provides an overview of the modelling approach taken to determine the base case energy and demand forecast through to 2045.

6.1 Underlying energy and peak demand forecast

We have adopted an econometric approach to forecast peak demand and energy consumption in the ACT. The econometric approach to forecasting sector energy consumption establishes a statistical relationship between peak demand and energy use and those factors that influence them. The peak demand and energy forecasting process can be broken down into five separate steps shown in Figure 20 below.

Figure 20 Steps in the forecasting methodology

01 Analyse & process data

Prior to specifying the econometric models, some adjustments to the historical data sets were made. Pre-model adjustments to the historical data include removal of:

- The impact of rooftop solar PV installations - the impact of rooftop solar PV systems are added back to the baseline forecasts as a post model adjustment (with the uptake of PV modelled separately)
- Weekends and other non-working days such as public holidays
- The first week before Christmas and two weeks after Christmas
- Checking and imputing for missing data where necessary

02 Specify & develop econometric models

In modelling energy and peak demand, we applied a multiple regression approach, establishing linear relationships between the energy and peak demand trends, and their underlying drivers. Model coefficients were chosen on the basis of minimising the difference between the historical values of energy and peak demand and the values predicted by the resulting linear equation.

We estimated the econometric relationship between annual energy/seasonal peak demand and its drivers using historical data, and regression techniques. We calibrate our econometric models using historical annual data for energy, and historical daily data for peak demand. We use daily data for peak demand to properly account for the relationship between peak demand and temperature.

We developed two peak demand models, one for each season. In specifying and estimating the models, we tested a number of economic, demographic and temperature drivers, including: GSP, population, real retail electricity prices, maximum and minimum daily temperature and seasonal monthly and day of week effects.

We modelled the energy and peak daily demand for winter and summer as a function of daily temperature and population. None of the other drivers were statistically significant.

03 Test & validate models

Each estimated model was validated using standard statistical diagnostic tools.

Three main methods of model validation were adopted, these being:

- The goodness of fit of the regression
- The statistical significance of the explanatory variables
- The theoretical basis of the coefficients' sign and size

04 Generate underlying forecasts

The estimated econometric models formed the basis of the underlying energy and peak demand forecasts. The final models produced estimates of all the coefficients needed to generate the forecasts. The underlying forecasts were obtained by applying those coefficients to the input forecasts.

To generate the weather corrected peak demand forecasts a stochastic (random) analysis was conducted on the calibrated summer and winter demand models to generate a distribution of seasonal peak demands. From this distribution, the 10 percent, 50 percent and 90 percent POE peak demand was derived. The 50 percent POE level of demand corresponds to the level of demand that is exceeded in 1 out of every 2 years. The 10 percent POE level of demand is exceeded in one out of every 10 years. The stochastic analysis involved 100 simulations based on 20 years of historical weather data, resulting in 2000 years of peak summer and winter season demands, from which the 10 percent, 50 percent and 90 percent POE peak demands were derived.

05 Post-model adjustments to underlying forecasts

Some forecasts were developed separately to the underlying energy and peak demand forecasts. These are required to capture factors that have not been included in the underlying models. These are referred to as post model adjustments. The main post model adjustments to the underlying forecasts are:

- Impact of rooftop solar PV
- Impact of energy storage technologies
- Uptake of electric vehicles
- Electrification of gas

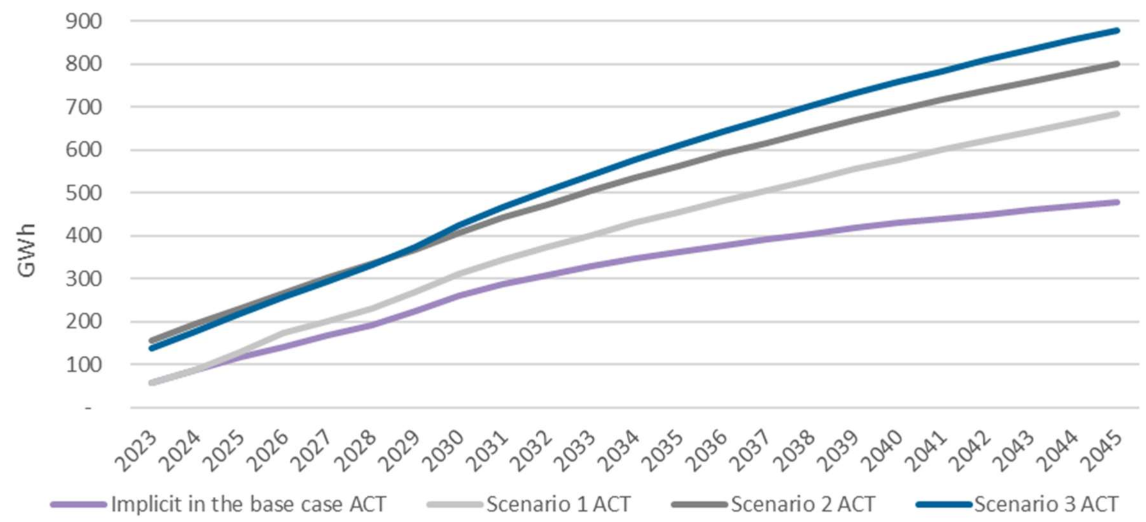
6.1.1 Energy efficiency forecasts

The energy efficiency savings factored into the modelling are derived from the AEMO ISP scenarios. The base case is derived from AEMO's 'slow growth' and 'steady progress' scenarios which assume no change to the current energy efficiency standards and measures, a low level of market-led/autonomous energy efficiency and no change to State based energy efficiency savings scheme levers. As such, the forecast level of energy efficiency savings is 'built in' to the underlying demand forecast and is not shown explicitly for the base case.

Key drivers of energy efficiency include (in order of magnitude of impact) changes to the National Construction Code (NCC) and Greenhouse and Energy Minimum Standards (GEMS); changes in the rate of market-led/autonomous energy efficiency; and changes to State based energy savings scheme levers.

The base case incorporates low-moderate (AEMO's labels) energy savings of around 485 GWh by 2045, which represents around 10.6 per cent of underlying electricity (base case) demand. In modelling the alternate scenarios we will adopt the various alternate ISP scenarios developed by AEMO. [16] A comparison of assumed ACT energy efficiency savings forecasts in GWh terms are shown for each in Figure 21. The scenarios will include an explicit amount of energy efficiency savings which will equal the amount of energy savings in GWh over and above the base case level.

Figure 21 ACT energy efficiency saving under various AEMO scenarios



Source: ACIL Allen based on AEMO ISP scenarios

The forecast update of the Building Code of Australia (BCA) (which translates to 6.5 stars by 2025 and 7 stars by 2040) is not incorporated into the base case, given it is yet to be implemented, but will be incorporated into Scenario 1.

The other two scenarios incorporate a higher level of energy efficiency, assuming the NCC is implemented from 2022 – that is, a full 7 stars from 2022. The trajectory beyond 2022 depends on the scenario but reflect the 'rapid decarbonisation' and/or 'export superpower' scenario assumptions for energy efficiency ('rapid decarbonisation' assumes 7 stars in 2022, 7.5 in 2027, 8 in 2030, 8.5 from 2035).

The energy efficiency savings (10.6 per cent of underlying electricity demand) reflect the energy efficiency initiatives ACT Government already has in place. While the impact at the level of the individual

[16] ACT was not modelled separately under the ISP. We have assumed that energy efficiency savings are around 5 per cent of total NSW energy efficiency savings, based on the relative population share between NSW and ACT.

building/appliance may be significantly higher, at the ACT level the impact is dampened (given some households may take no action).

The age, turnover, and condition of the existing ACT building stock will also limit the scope for action. Given many existing homes and appliances are already reasonably efficient (with relatively new appliances far from end-of-life turnover), scope to pursue appliance replacement in the near future may be limited. Consumers are also locked into 'status-quo' considerations and may resist change to more efficient (but unknown) options, i.e., conversion of gas cooktops to electric.

6.2 Use of load profiles

Historical zone substation half hourly data[17] is used as the total ACT system load profile. Unless otherwise stated, 'years' refers to financial years ending 30 June.

- The Net System Load Profile (NSLP)[18] for the ActewAGL distribution network is used as the representative load profile for residential customers given the majority (about 65 per cent) of residential customers in the ACT are on accumulation (or Type 6) meters.
- The load profile for non-residential customers in the ACT is found by taking the difference at the half hourly level between the zone substation data and the NSLP data and scaling to match the historical annual energy parameters of non-residential customers.[19]

6.3 Developing the demand profile

The seasonal peak demand and annual energy forecasts for the ACT demand profiles consider past trends and relationships between residential and non-residential underlying demand.

We used several years of historical load data together with the P10, P50 and P90 seasonal peak load, and energy forecasts from the underlying energy and peak demand forecast above to produce multiple simulated representations of the hourly load profile for a year using a Monte Carlo analysis. These multiple simulations include a mix of mild and extreme representations of demand – reflecting different annual weather conditions (such as mild, normal, and hot summers).

The key steps in developing the demand profiles were:

- Half-hourly demand profiles of the past four years are obtained. The profiles are adjusted by 'adding' back the estimated rooftop PV generation for the residential and non-residential traces.
- A stochastic demand model is used to develop about 20 weather influenced simulations of hourly demand traces for the residential and non-residential demand. The approach takes the past three years of actual demand data, as well as the past 20 years of weather data and uses a matching algorithm to produce 20 sets of weather-related demand profiles of 17,520 half-hourly loads. This approach does not rely on attempting to develop a statistical relationship between weather outcomes and demand – instead, it accepts there is a relationship and uses a matching algorithm to find the

[17] ACT zone substation data: **https://www.evoenergy.com.au/about-us/about-our-network/zone-substation-data**, accessed on 22nd September 2021
[18] ActewAGL NSLP data: **https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/metering-data/load-profiles**, accessed on 22nd September 2021
[19] Non-residential = LV commercial plus HV. Historical annual energy, by residential, LV commercial and HV customers provided by Evoenergy via this consultation.

closest matching weather outcomes for a given day across the entire NEM from the past three years to represent a given day in the past.

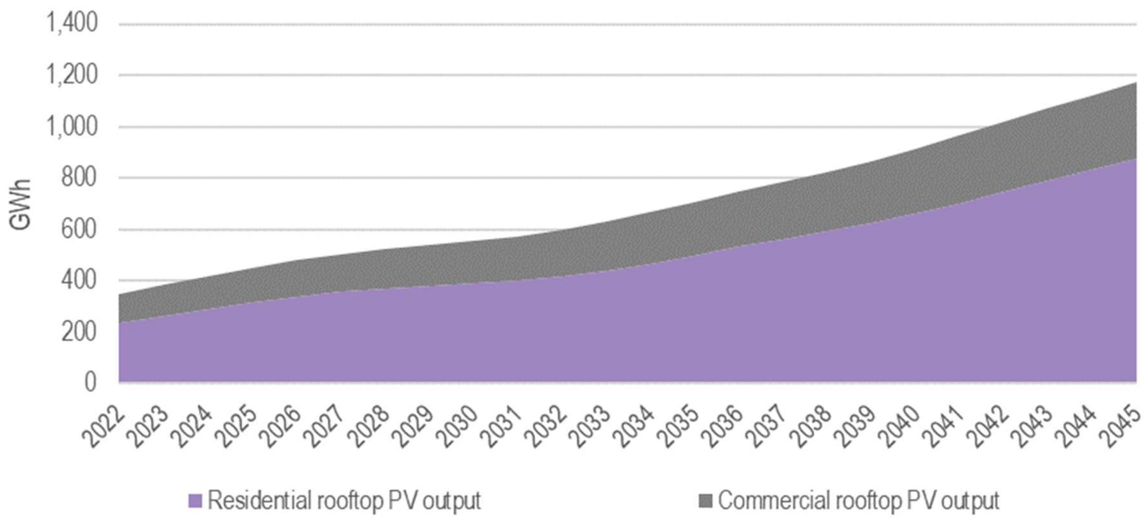
- The set of 20 simulations of residential and non-residential demand was then grown to the demand forecast using a non-linear transformation so that the average annual energy across the 20 simulations equals the energy forecast, and the distribution of annual seasonal peak loads across the 20 simulations generally matches the distribution of peak loads inferred by the P10, P50 and P90 seasonal peaks from the demand forecast.

6.4 Projection of rooftop solar PV uptake

The projected uptake of rooftop PV is obtained using the ACIL Allen's internal rooftop PV uptake model as illustrated in Figure 22. The model assumes a split between residential and commercial rooftop PV based on installation size.[20]

The projections for uptake of rooftop PV systems are a function of payback periods for residential and business customers taking into consideration the number of suitable dwellings, roof-space, and saturation levels. Inputs for the uptake model consist of system costs, retail electricity prices and government feed-in-tariffs and upfront subsidies.

Figure 22 Projected rooftop PV output in the ACT, by consumer type (GWh)



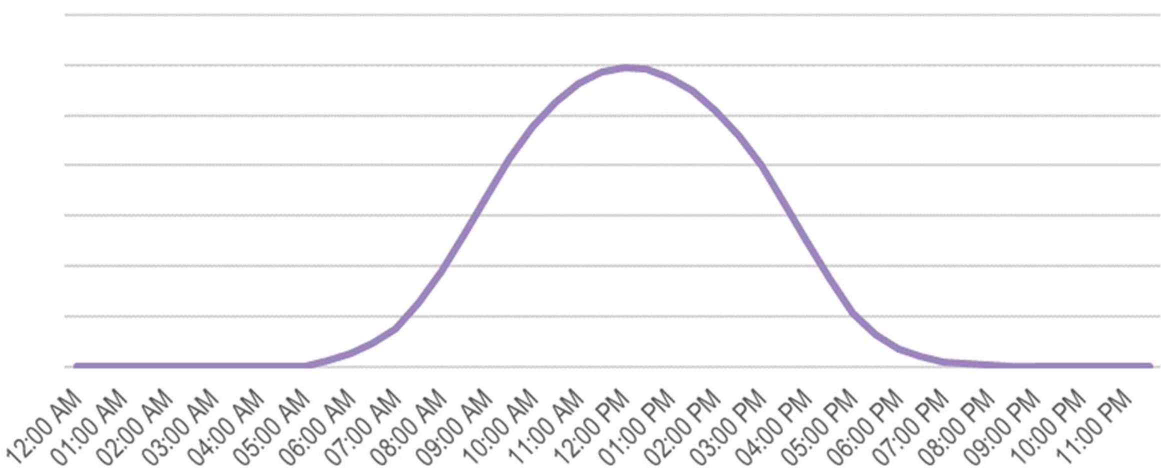
Note: Installations less than 100 kW.
Source: ACIL Allen

[20] Installations in the ACT that are greater than 10kW are assumed to be commercial.

6.4.1 Growing the rooftop PV generation traces for each year

We have constructed a representative hourly PV output trace for PV systems installed in each region as illustrated at Figure 23. We derived the traces from data on real system output obtained from pvOutput.org.[21] We then scaled these traces to the assumed annual generation parameters. We then deducted the scaled traces from the projected hourly underlying demands.

Figure 23 Annual average time of day rooftop PV generation profile



Source: ACIL Allen; pvOutput.org

6.5 Behind the meter battery energy storage systems (BESS)

The projected uptake of BESS is obtained (using ACIL Allen's internal battery uptake model). The projected uptake is shown Figure 24.

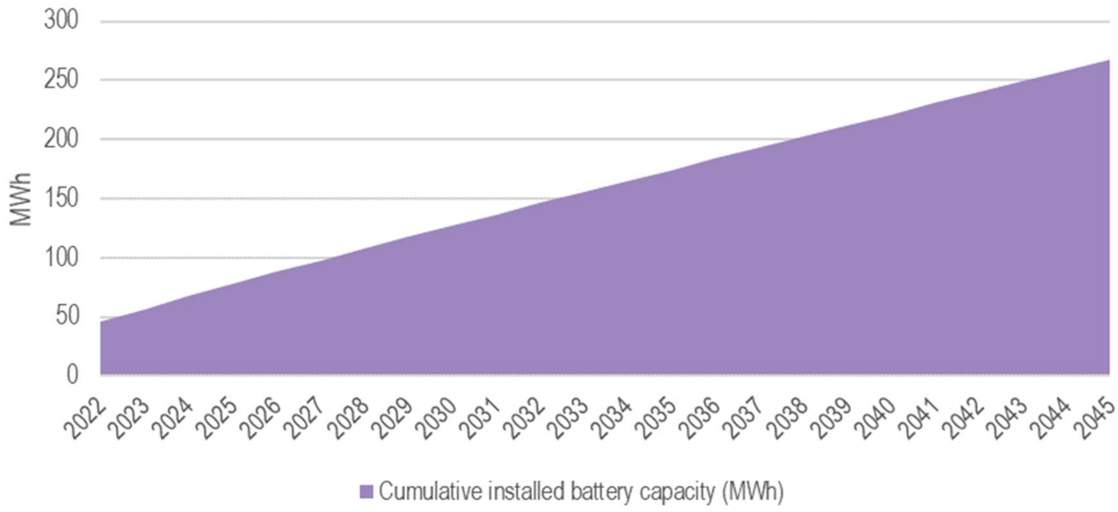
The BESS uptake model relates installation rates of home BESS to the net present value (NPV) a household achieves by installing such a system. We have assumed that the relationship between NPV and installations rates of home BESS will be like the relationship between NPV and installation rates of PV systems, which is observable. We assume all existing and future solar installations to be candidates for the installation of BESS.

The economics of battery installations are also affected by the technical characteristics of battery technology. The nature of battery cycling affects battery life – non-optimal cycling can lead to shorter battery life. We assume daily cycling of the battery with a depth of discharge of 80 per cent and a lifetime of 10 years (equivalent to 3,650 cycles in its lifetime).

For our projections, we have assumed that battery costs decline on average by six per cent and 1.5 per cent per annum in real terms over the periods 2022-2030 and 2031-2045, respectively, based on assumed rates of technology and production improvements and consistent with cost declines in recent years.

[21] pvOutput is an online service for sharing and comparing PV output data - **https://pvoutput.org/**

Figure 24 Projected cumulative installed behind the meter BESS capacity (MWh) in the ACT



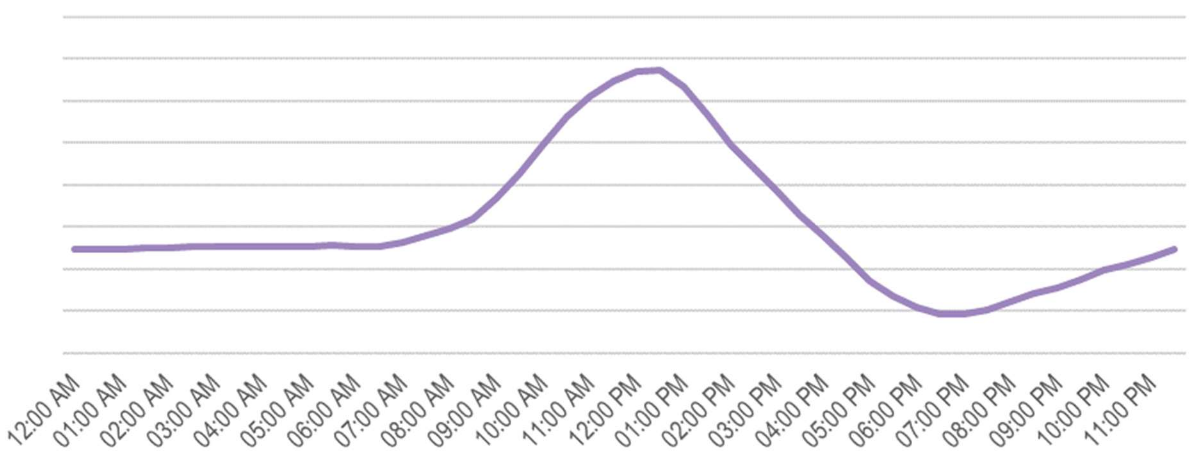
Source: ACIL Allen

6.5.1 Growing the BESS operation traces for each year

The impact of home energy storage systems will depend on the way these systems are charged and discharged as well as the overall system size.

We have assumed that charging and discharging will occur, based on a daily cycle, where excess solar generation is stored until the storage capacity is reached as illustrated in Figure 25. Once household electricity demand exceeds solar generation, the storage system is fully discharged – typically during the evening peak. Like the treatment of rooftop PV, the BESS operation trace is grown and deducted from the projected underlying hourly demands.

Figure 25 Annual average time of day BESS operation profile

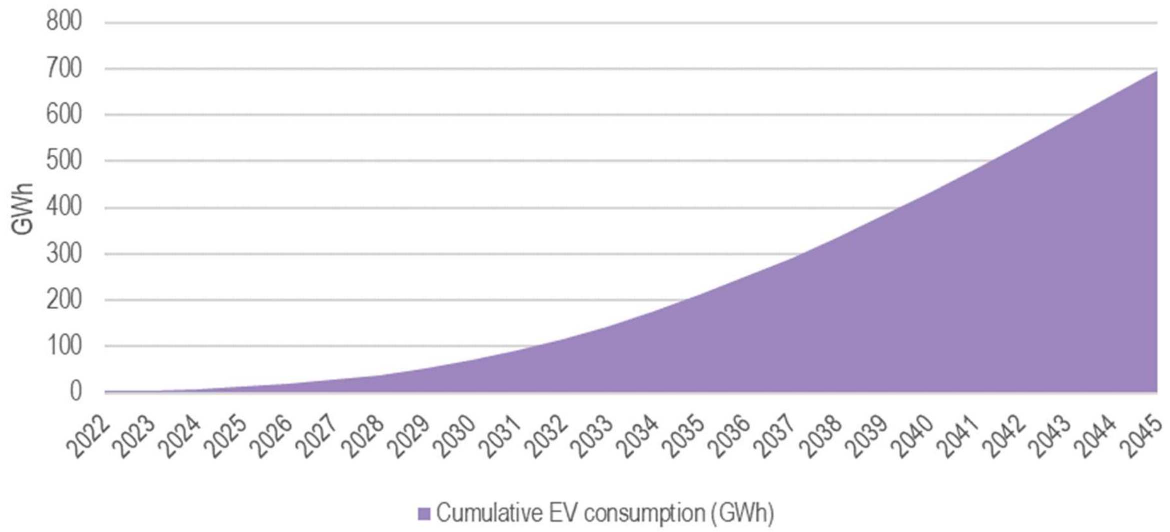


Source: ACIL Allen

6.6 Zero Emission Vehicles (ZEVs)

As agreed, we have adopted a projection on the uptake of passenger ZEVs in line with ‘conservative’ EPSDD projections (as per provided (confidential) Deloitte analysis). This is illustrated at Figure 26. The projected uptake of ZEVs in the ACT suggests little uptake prior to 2025. This is not surprising given the price differential between EV and conventional vehicles at present, as well as the limited choice of model.

Figure 26 Projected annual energy requirements of passenger ZEV charging (GWh)

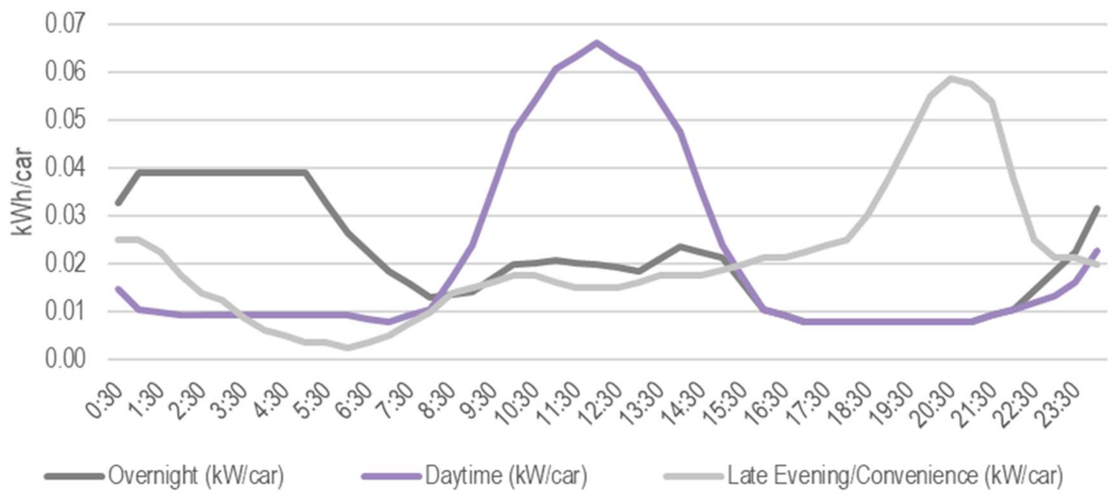


Source: Projections obtained from the EPSDD ‘2021-ACT ZEV Key insights (Confidential ’Deloitte report)

6.6.1 Growing the EV charging traces for each year

We have assumed three different charging profiles for ZEVs, namely a late evening or ‘convenience’ profile, a daytime profile and an overnight profile as shown at Figure 27. The ‘convenience’ profile has its peak between 18.00 and 22.00, the overnight profile has its peak in the early morning between 1.00 and 5.00 and finally the daytime profile has its peak during the day between 10.00 and 14.00.

Figure 27 Average time of day ZEV charging profiles (kW/car)

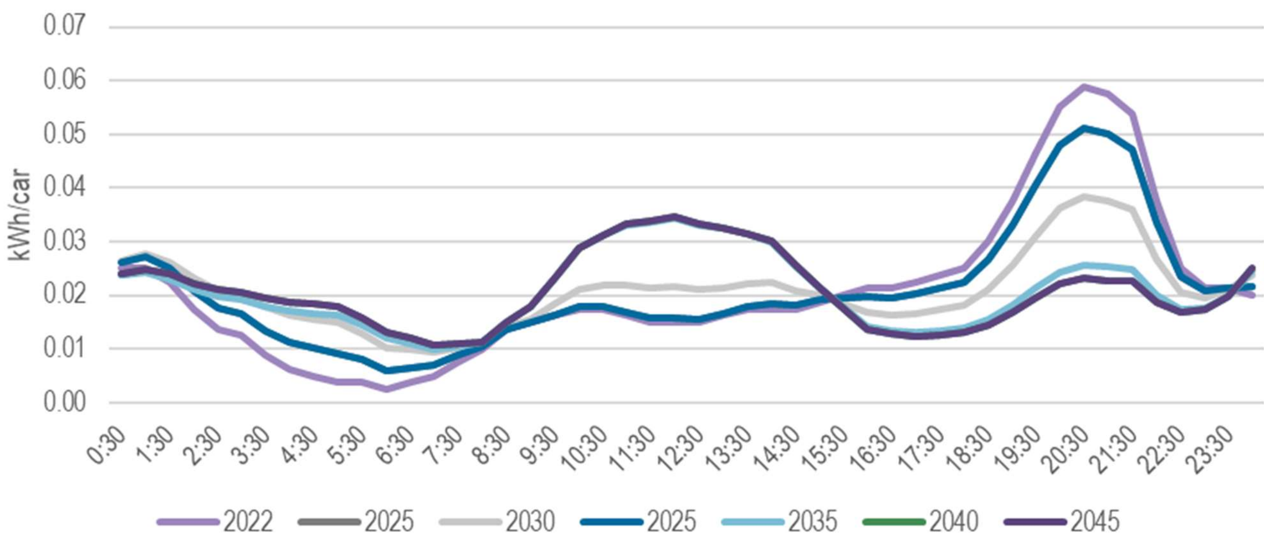


Source: ACIL Allen analysis of AEMO data

We assume the ZEV fleet adopts a mix of these charging profiles, and the mix evolves throughout the projection period. Initially, the charging regime of the ZEV fleet is skewed towards the 'convenience' profile, with most charging occurring over night at households where the ZEVs are garaged since it is likely that most ZEV owners charge their ZEVs at home, given the lack of availability and accessibility of rapid charging stations at different locations.

As charging infrastructure is further developed, charging speeds increase and there is a further evolution in battery swap systems, coupled with electricity tariff reform, we expect a higher proportion of ZEVs to be charged during the day, allowing them to take advantage of lower daylight hour electricity tariffs. This means that, over time, the charging profile shifts from a late evening peak to a daytime peak as illustrated at Figure 28.

Figure 28 *Weighted average combined time of day ZEV charging profile (kW/car)*



Source: ACIL Allen analysis of AEMO data

6.7 Electrification

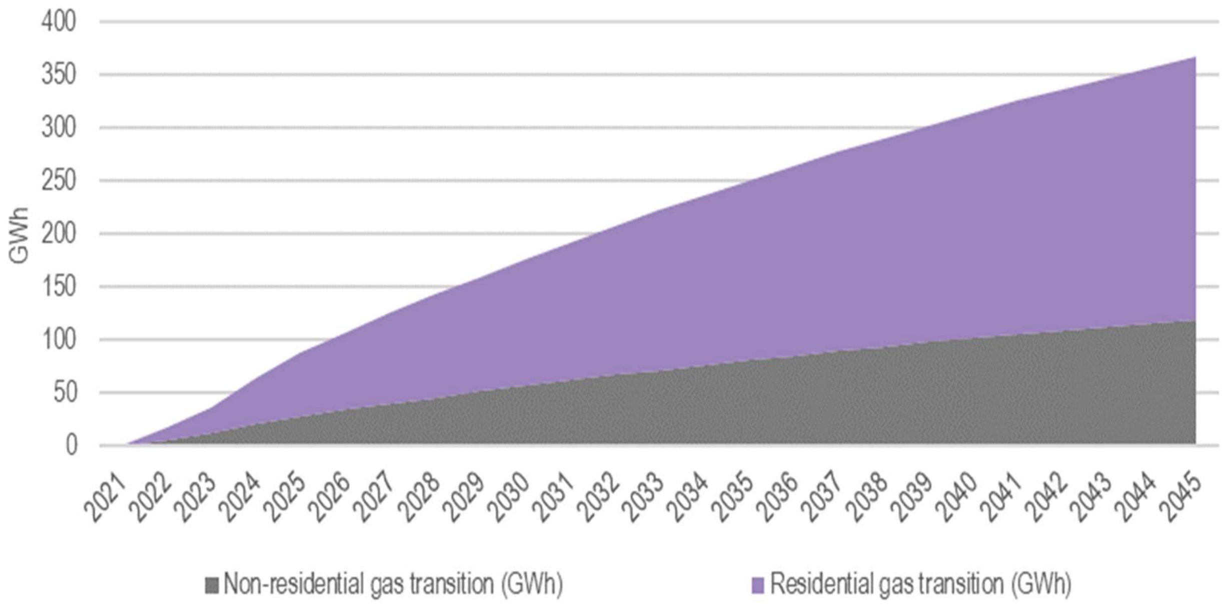
The base case incorporates the transition away from natural gas by residential and non-residential customers in the ACT, as discussed in Chapter 5. The projected natural gas transition has been converted into electricity demand using conversion factors and representative hourly profiles for space heating, hot water, cooking and industrial processes.

Most gas consumption across the ACT is for space heating (around 75 to 80 per cent). Therefore, the overall consumption profile is seasonal (winter peaking) and has a low load factor, reflecting that heating requirements are significantly larger during certain times of the day (for example, morning and evening).

For residential customers, the assumption for the remaining gas consumption is hot water (~25 per cent) and cooking (~two per cent). For non-residential- customers, the assumption for the remaining gas consumption is hot water (~11 per cent), cooking (~two per cent) and industrial processes (~five per cent) such as incineration and asphalt manufacturing.

Figure 29 shows projected annual energy requirements from natural gas transition by customer type.

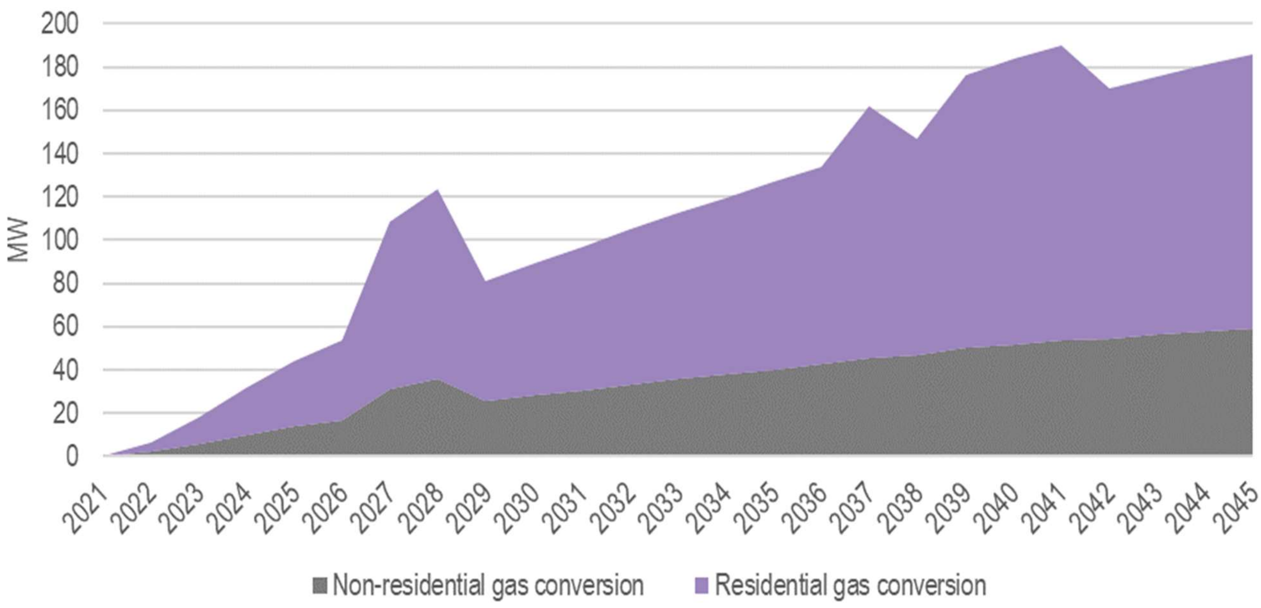
Figure 29 ***Projected energy requirements from natural gas transition (GWh)***



Note: excludes Canberra Hospital and CNG bus fleet
Source: ACIL Allen analysis

Projected winter peak requirements attributed to natural gas transition under the base case are shown in Figure 30.

Figure 30 ***Projected contribution to the (winter) 50POE peak by natural gas transition (MW)***



Note: Contribution of gas transition on the day and time of total ACT system 50POE peak demand. Non-residential gas conversion in this figure excludes Canberra Hospital and CNG bus fleet. There is no fundamental assumption driving the 'spikes' in the projected winter peak requirements attributed to gas transition in 2027, 2028, 2037, 2039-2041, rather it is purely a result of the model selecting a weather year/simulation that has a higher contribution from gas transition and a corresponding lower contribution from another demand category such as base residential demand. These 'spikes' don't impact total ACT P50 peak demand, which is 'smooth' year-to-year, as shown in Figure 36 in the 'Final energy and demand' section below.
Source: ACIL Allen analysis

Historical half hourly gas flows measured at the entry point onto the Canberra Primary System at Watson and at the entry point onto the Hoskinstown-Fyshwick pipeline have been used to create demand profiles for residential and non-residential customers transitioning away from gas.

We have split the historical half hourly gas flows into uses (space heating, hot water, cooking, and industrial processes) at the half hourly level using the assumed percentages stated above and representative average seasonal time of day profiles.

Table 5 sets out our assumed conversion rates for the main uses.

Table 5 Conversion factors

Use	Performance	Efficiency	Total conversion rate (GJ=> MWh)	Assumption
Space heating	2.5	85%	0.09	Average COP of 2.5. Average gas heater efficiency of 85%.
Hot water	2.0	85%	0.12	Average COP of 2. Average gas heater efficiency of 85%.
Cooking	0.75	40%	0.15	Average performance of electric cookers 75%. Average gas cooker efficiency of 40%.

We have then converted gas demand at the half hourly level into electricity demand at the half hourly level using appropriate conversion rates for each gas use (space heating, hot water, cooking and industrial processes).

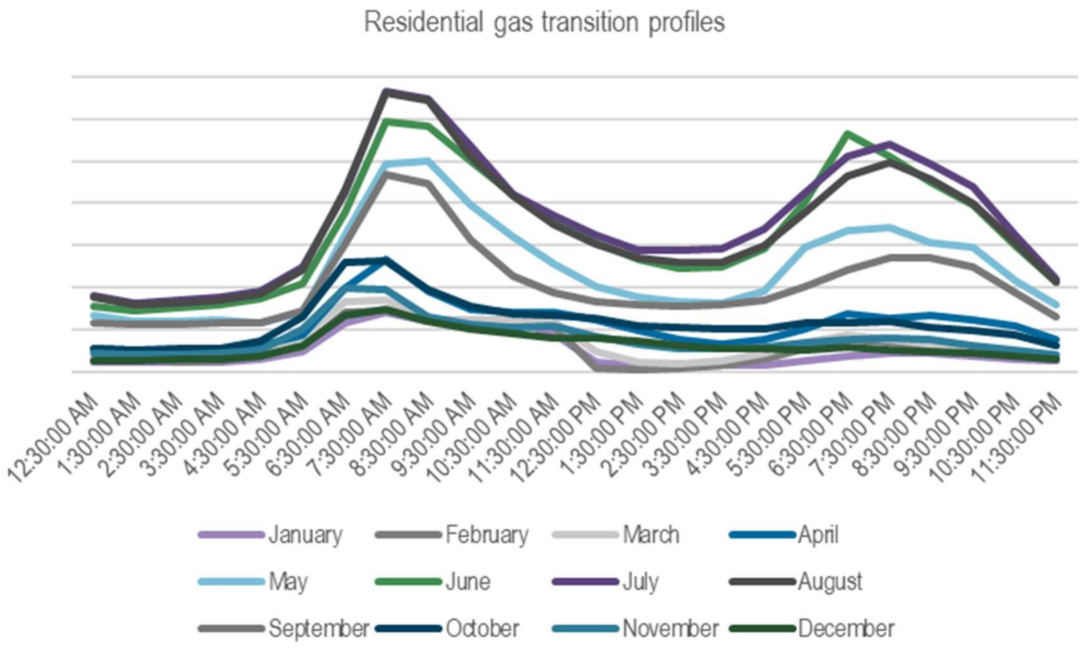
An approach like the one taken to create underlying electricity demand traces (refer Section 6-3) has been used to create representative hourly traces for residential and non-residential customers transitioning away from gas:

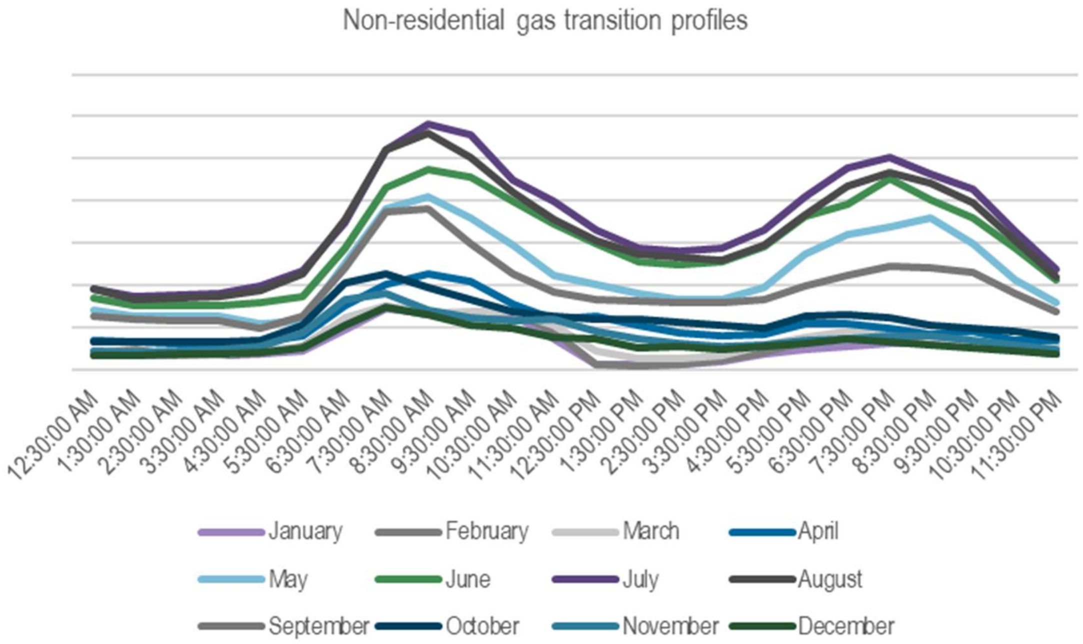
- using the past three years of actual gas demand data (converted to electricity demand using the method described above) as well as the past 20 years of weather data, we have used a matching algorithm to produce 20 sets of weather-related gas transition demand profiles of 17,520 half-hourly loads
- the set of 20 simulations of residential and non-residential demands is then grown to the annual gas transition demand projection using a non-linear transformation.

Average seasonal time of day electricity demand profiles for the gas transition component by residential and non-residential customers are provided in Figure 31.

Both residential and non-residential customers show a similar consumption pattern on an average seasonal time of day basis due to space heating being a significant percentage of gas use for both segments of the market. The non-residential profiles have a slightly higher load factor, reflecting the small amount (~five per cent) of industrial processing.

Figure 31 Average seasonal time of day for gas transition - residential and non-residential customers





Source: ACIL Allen analysis based on historical half hourly gas flows provided by Evoenergy

The base case also incorporates the electrification of several explicit customer loads including:

- Canberra Hospital
- Molonglo Commercial Centre
- CIT Woden
- Action Bus Fleet
- Canberra Light Rail Stage 2.

Projected annual electricity requirements for the Canberra Hospital, Molonglo Commercial Centre and CIT Woden are estimated using typical conversion factors and estimated floor space.

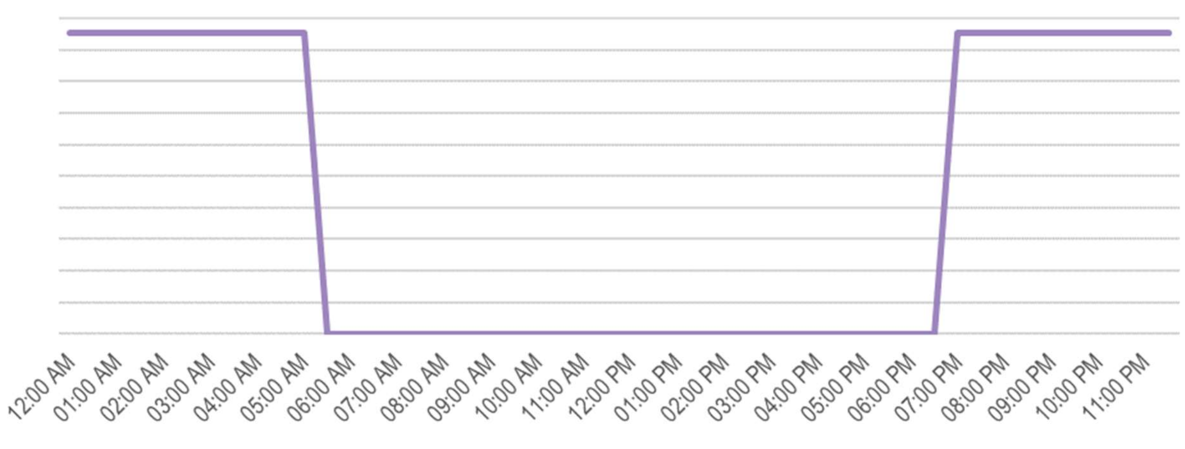
- The Molonglo Commercial Centre is assumed to be an all-electric commercial centre of around 60,000 square metres of floor space to cater to a variety of commercial, retail, community and entertainment uses. We assume the Commercial Centre is expanded in a linear projection to the full 60,000 square metres over the period from 2022 to 2032, resulting in an annual energy requirement of around 14.5 GWh by 2032.
- Canberra Hospital is assumed to be fully electrified by 2024, which includes the transition away from existing gas use of around 171 TJ of 2019-20[22] and the proposed expansion of approximately 40,000 square metres, resulting in an annual energy requirement of around 25 GWh by 2024.
- CIT Woden is assumed to comprise 22,500 square metres of new educational and community facilities at Woden Town Centre beginning in 2025, resulting in an annual energy requirement of around 5 GWh by 2025.

The simulated underlying demand trace for non-residential customers (refer Section 6.3), has been used to develop the hourly demand projections of the Hospital, Molonglo Commercial Centre, and CIT Woden.

Annual electricity requirements for the Action bus fleet are estimated based on 90 new electric buses to be introduced by 2024 followed by phased implementation (linear projection) of the remaining bus fleet from 2025, reaching 100 per cent in 2040. The fleet currently consists of 450 buses with anticipated growth of 100 additional buses by 2030, resulting in an annual energy requirement of around 20 GWh by 2040.

Projected hourly energy requirements of the bus fleet are based on average time of day charging profiles for buses, which on the advice of the client comprise of overnight charging as shown in Figure 32.

Figure 32 Average time of day bus charging profile



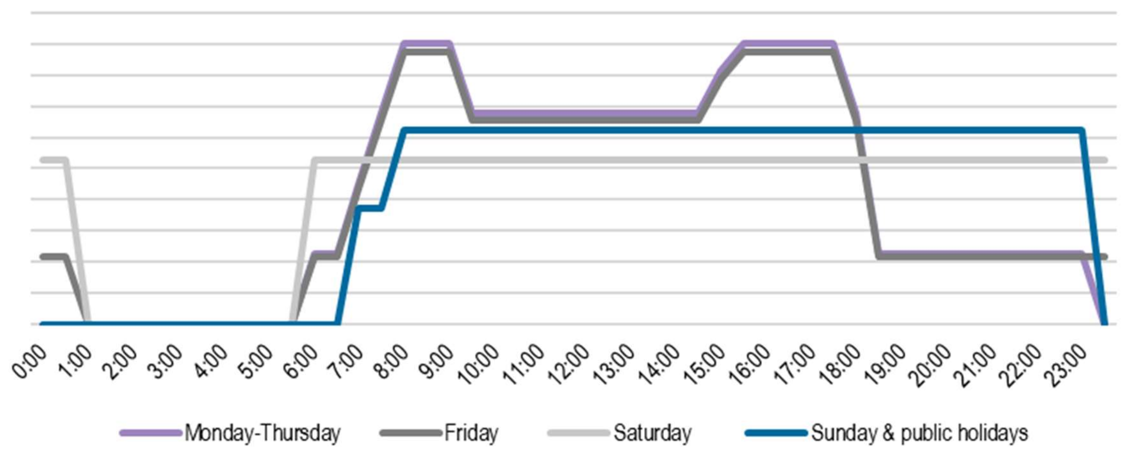
Source: ACIL Allen analysis based on information from EPSDD

Annual electricity requirements for Stage 2 of the Light Rail, which has a proposed length of around 11 kilometres, are estimated based on a pro-rata energy requirement per kilometre of Stage 1, resulting in a projected annual energy requirement of around 2.6 GWh by 2025.

[22] Canberra Health Services Annual Report, Page 96

Projected hourly energy requirements of Stage 2 of the Light Rail are based on average time of day charging profiles comprising a Monday-Thursday working day profile, a Friday working day plus late evening profile, a Saturday weekend profile and a Sunday/public holiday weekend profile, as shown in Figure 33.

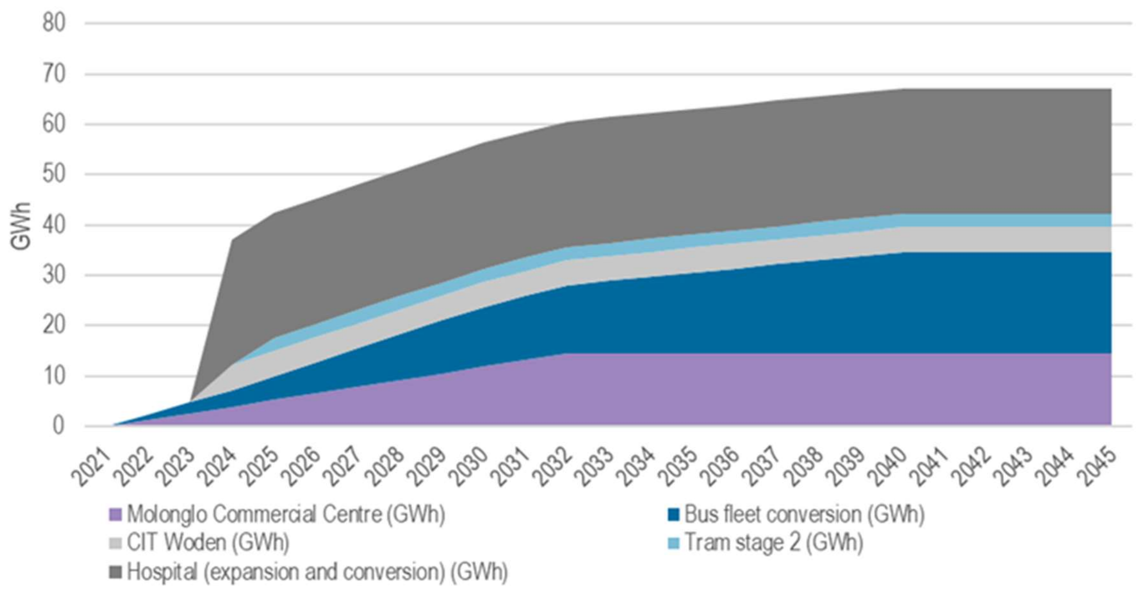
Figure 33 Average time of day Light Rail stage 2 charging profiles



Source: CMET Frequency Guide, confidential information from the client, ACIL Allen analysis

The projected impact on energy requirements in the ACT over the projection period from electrification of Canberra Hospital (conversion of existing natural gas use plus electrification of expansion), Molonglo Commercial Centre, CIT Woden, the Bus fleet, and Light Rail Stage 2 is shown in Figure 34.

Figure 34 Projected energy requirements of electrification of specific commercial loads (GWh)

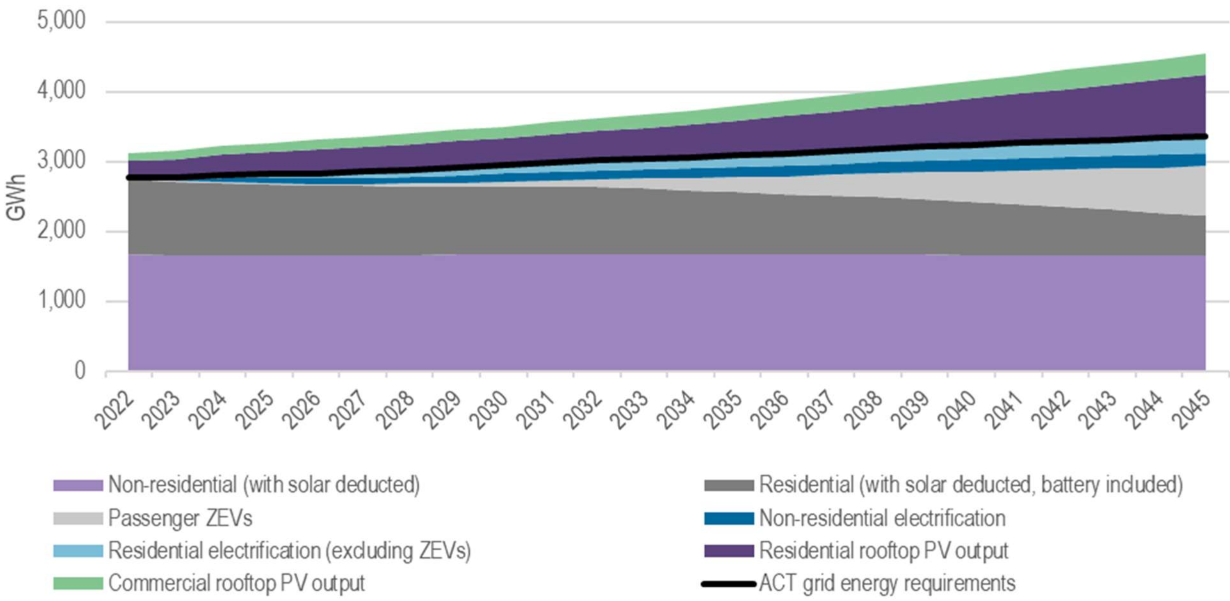


Source: ACIL Allen analysis based on information provided by the client

6.8 Final energy and demand

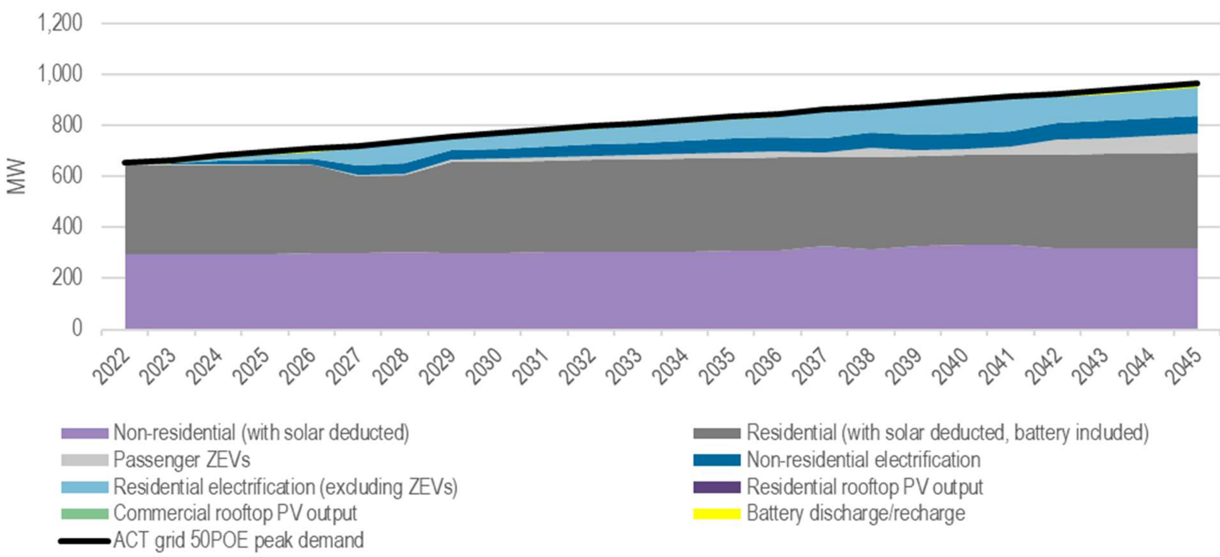
Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, Figure 35 and Figure 36 below show the final assumed annual energy and peak demand projection. ACT total demand is projected to grow from 2,772 GWh in 2022 to 3,367 GWh in 2045, which is an increase of around 21 per cent over the projection period. ACT 50POE peak demand is projected to grow from 654 MW in 2022 to 966 MW in 2045, which is an increase of around 48 per cent over the projection period.

Figure 35 Projected energy requirements (GWh) – by category



Note: non-residential electrification includes general natural gas transition of non-residential customer as well as electrification of specific commercial loads of Canberra hospital, Molonglo Commercial Centre, CIT Woden, Bus fleet and Light Rail stage 2.
Source: ACIL Allen

Figure 36 Projected 50POE peak demand (MW) – by category



Note: The contribution of each of the categories are shown at the time and day of the projected 50POE peak demand of the total ACT system. The contribution of rooftop solar PV and home batteries to peal demand is zero or very small. Non-residential electrification includes general natural gas transition of non-residential customer as well as electrification of specific commercial loads of Canberra hospital, Molonglo Commercial Centre, CIT Woden, Bus fleet and Light Rail Stage 2.
Source: ACIL Allen

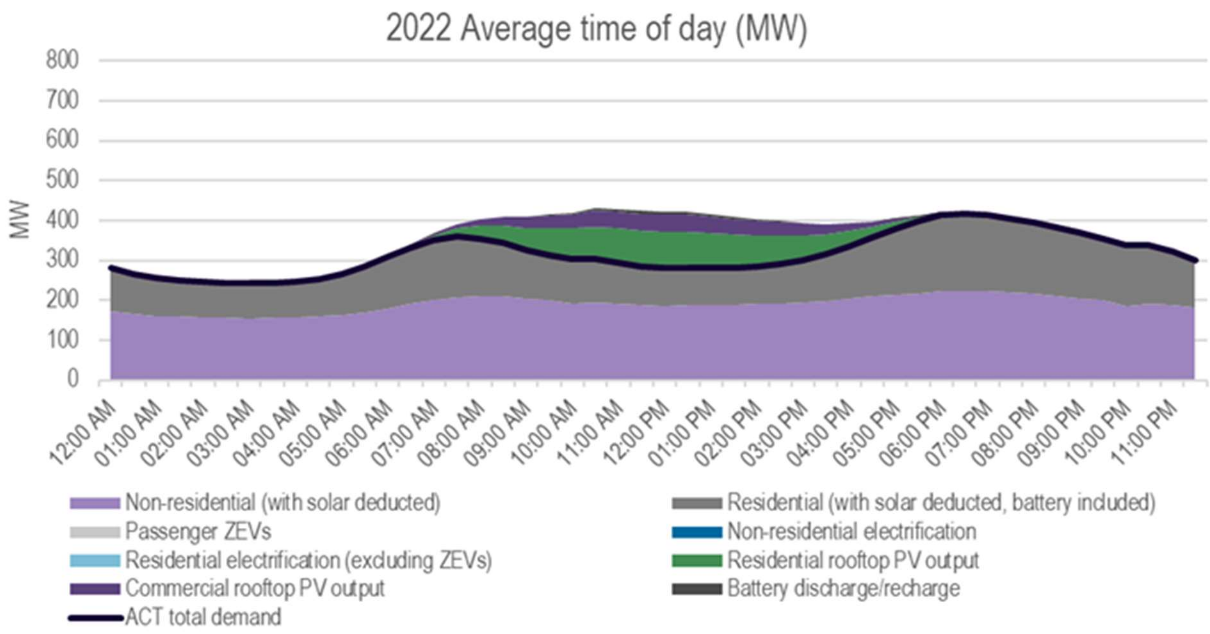
6.8.1 Average time of day demand

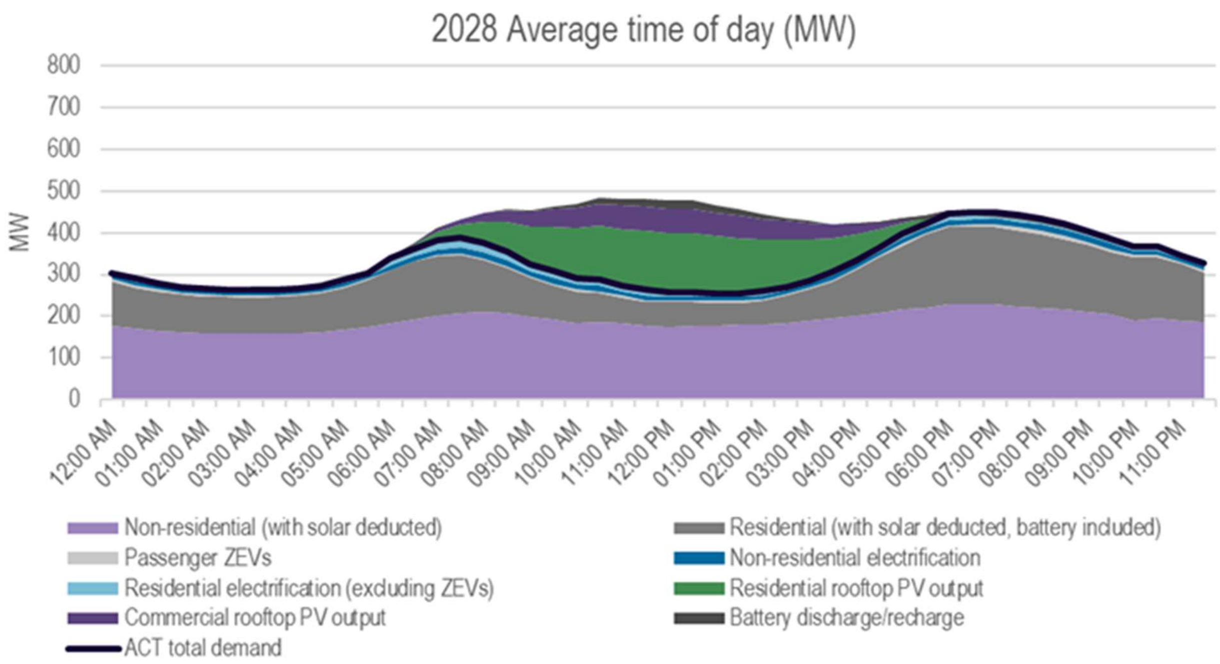
The projected continued uptake of rooftop PV installations, storage and electrification will continue to change the shape of the time-of-day profile of demand in the ACT.

Figure 37 illustrates the impact of these technologies on the average time of day operational demand profile for 2022, 2028, 2033 and 2045.[23]

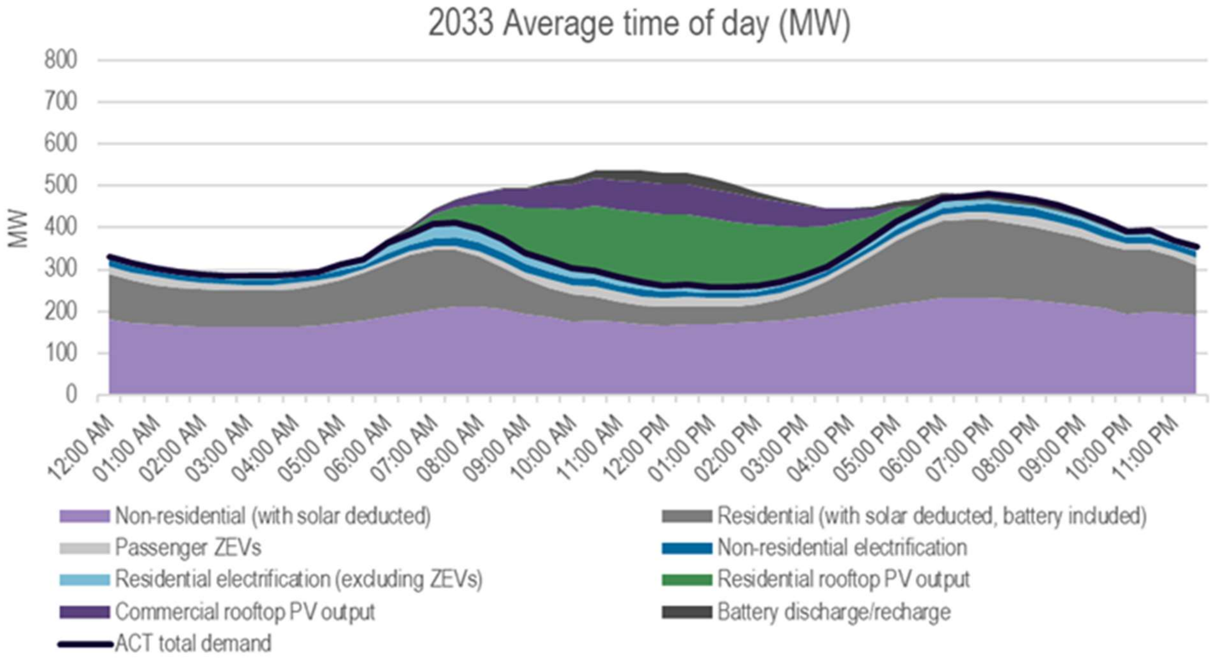
The graphs show the continuation of the hollowing out of the demand profile across daylight hours because of rooftop PV, and growth in demand during the evening because of electrification. By comparison, the impact of storage on the demand profile is reasonably small, given the level of uptake projected.

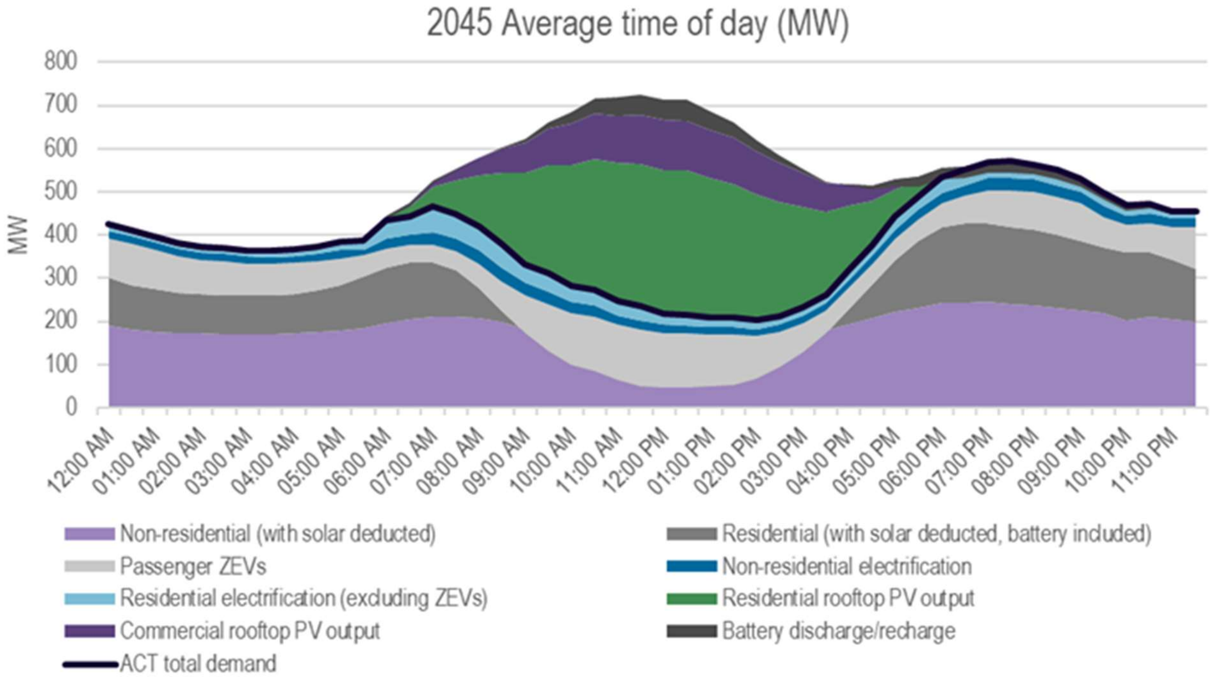
Figure 37 Average time of day demand (MW) – for selected years





[23] The mid-point dates (2028 and 2033) are selected to align with Evoenergy's regulator review periods.





Source: ACIL Allen

7. Electricity system network analysis

Currently, in the Evoenergy network the most significant constraints are in the Woden/Molonglo area. Evoenergy have already commenced work to address the constraints through the installation of the new Molonglo battery substation to relieve the peak loading constraints at the Woden zone substation.

The Woden/Molonglo area continues to be the area most significantly impacted by ACT population growth. The Molonglo battery station will need to be converted into a full zone substation and the addition of a further zone substation in the region will be required to service this growth.

Other areas of significant investment include the addition of extra transformation capacity at Gold Creek, East Lake and Belconnen zone substations to meet growth in the areas. Additional works have also been identified involving the construction of additional distribution feeders in the areas of East Lake, City East, Civic, Gold Creek Belconnen and Telopea Park. These new feeders are primarily to facilitate the connection of new customers and loads and to provide transfer capacity between substations, in particular between Telopea Park and East Lake.

7.1 Power modelling

Power modelling has been performed to identify and quantify future levels of investment into the Evoenergy electricity network to aid in identifying the cost that would be passed onto energy consumers to maintain the network to current levels of safety, security and reliability.

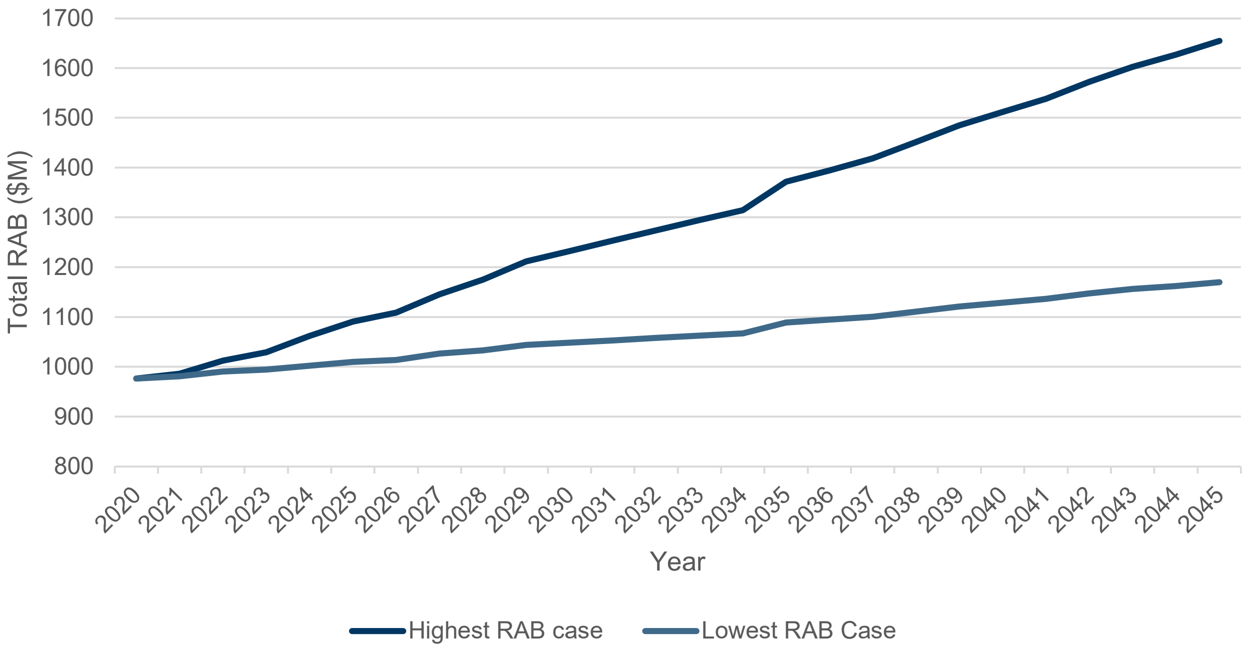
To estimate the change in costs to consumers, the network RAB size is considered as a relative measure of network size that can be referenced for determining cost passed onto consumer. Growth in the RAB is dependent on a combination of the mix of investments that are performed on the network and the financial treatment of investments, existing assets and other economic factors such as escalation.

Investments in the RAB has been grouped into three specific cost areas:

- assets added to the network to address location non-specific growth in demand
- assets added to the network to address location specific growth in demand
- assets added to the network to address location non-specific DER.

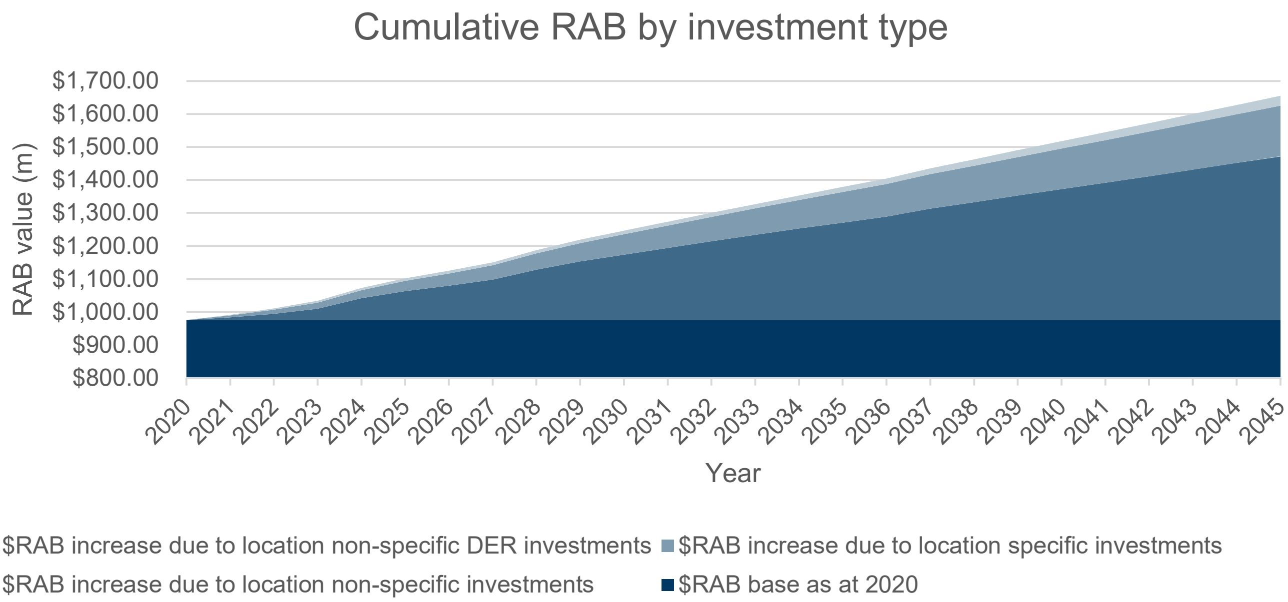
When considering the outcome on the RAB based on the investments and other economic factors a conservative, worst-case scenario (largest impact on customer tariffs) approach has been taken in the modelling, which is a case where escalation is highest, depreciation is near zero and there are no retirements. In Figure 38 the range of the RAB between the most extreme cases is shown. All other modelling only considers the worst-case (highest) scenario RAB.

Figure 38 *Comparison of highest and lowest possible RAB outcomes*



In Figure 39 costs for location specific investments have been spread throughout the period, rather than being placed in the year when the augmentation is required. This is because investments for augmentation typically occur in the years prior to when the augmentation is required, reflecting the purchase of long lead time materials, design and other pre-commissioning costs and because the cost that the customer will pay in their tariff will ultimately be based on 5-year periods of Evoenergy's price review period.

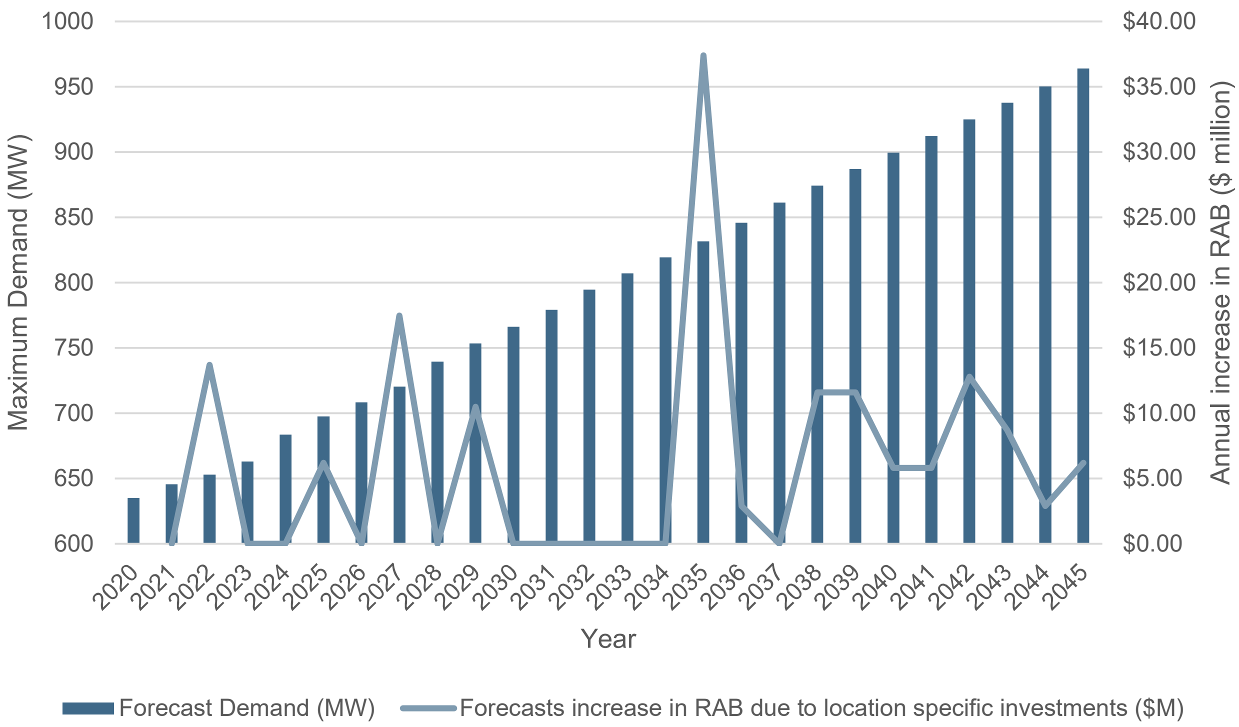
Figure 39 *Annual changes in RAB based on projected growth in demand and DER penetration*



7.1.1 Identification of network investments and determination of cost to consumers

Network investments contribute to RAB for Evoenergy and the RAB is a measure of the size of the network which needs to be maintained to ensure customers continue to receive safe, secure and reliable energy as indicated at Figure 40. We have (1) compared the historic RAB to historic tariffs to forecast a price for customers; and (2) identified investments using the forecast network demand as outlined in Section 7.1.2

Figure 40 Assets added to the network to address location specific growth



Costs for forecast investments have been determined using the average cost of similar investments that have been published as part of Evoenergy's Annual Planning Report and Regulatory Investment Tests.

7.1.2 Assets added to the network to address location non-specific growth in demand

Assets added to the network to address location non-specific growth relate to the minor works required to grow the network to connect additional customers and continue to supply existing customers where demand is increasing. This is typically short lengths of high and low voltage cables and smaller distribution substation augmentations required to facilitate the connection of new customers. It is also considered to be the native growth in the RAB.

In the context of the ACT, it is expected that the connections expenditure element will be mostly in the areas of high population growth, in both new development in green fields areas and in areas where conversion of existing structures into higher density residences such as multi-story apartment buildings is occurring. The anticipated green fields areas are predominantly Woden/Molonglo and Gold Creek which would mostly see the extension of existing HV and LV networks to connect more customers.

The anticipated areas of increased population density are predominantly in the Civic and City East areas where the existing HV cables may be replaced to increase capacity and distribution transformers and LV circuits augmented to supply the additional customers.

Beyond the areas of major growth, it is expected that there will still be a small number of customer connections in other areas that are also included in the location non-specific growth.

Location non-specific growth expenditure related to growth in demand of existing customers rather than connections is expected to occur in all areas of the network. It is generally expected to be greater in more residential areas due to the growth in demand largely being related to transition from gas to electric appliances and growth in EV.

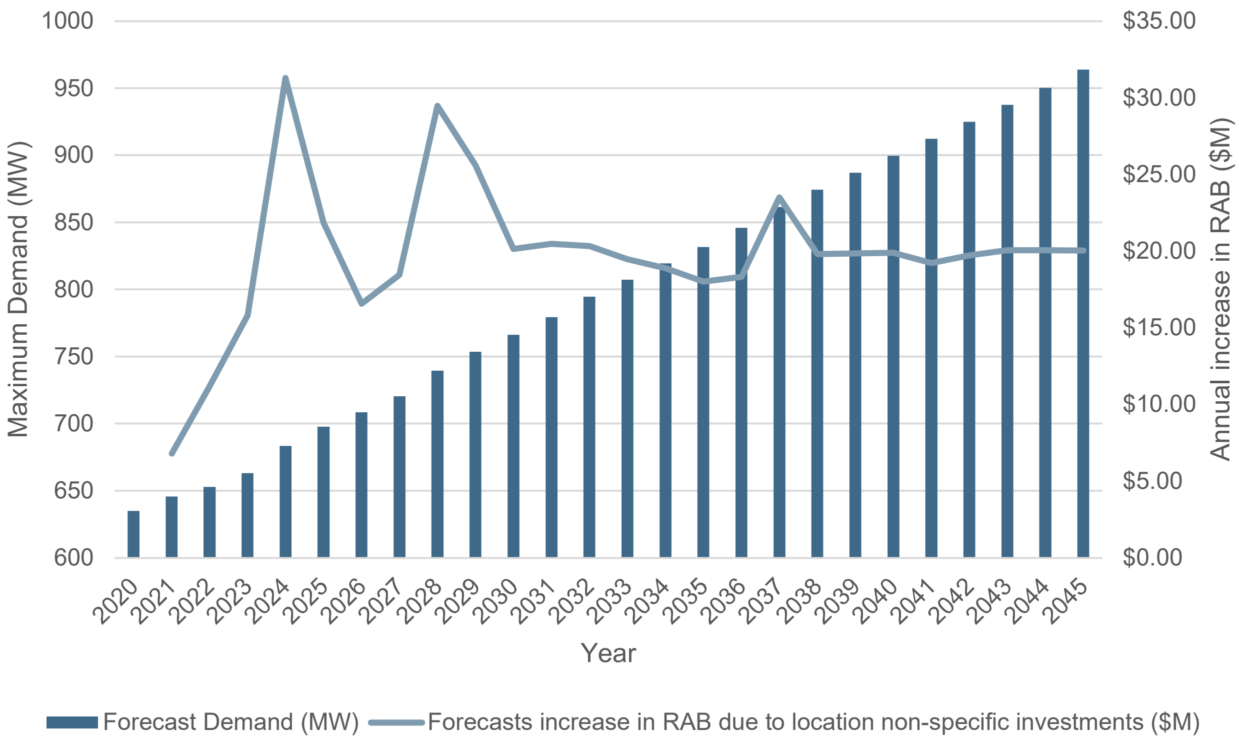
This expenditure will typically be for replacement of existing high and low voltage cables and substations with equipment of larger capacities. There will also be some work required to rearrange high and low voltage networks as new feeders identified in the location specific investments are built.

Calculation of the growth in the RAB due to new non-specific growth has been determined by considering the growth in the network maximum demand:

- the ratio of total RAB to network maximum demand has been calculated using the five most recent Evoenergy Regulatory Information Notices (RINs) published on the AER's website
- the average of the ratio has been taken and applied to the forecast network maximum demand determine the native growth in RAB in each scenario

the results of this calculation for the base case scenario are shown in Figure 41.

Figure 41 ***Forecast change in annual demand and annual increase in RAB forecast to connect additional customers***



Historically the make-up of this type of expenditure in the Evoenergy network is categorised as shown in Table 6.

Table 6 Historic break up of location non-specific demand driven expenditure in EvoEnergy network 2015-2020

Equipment category	Percentage of augmentation/connections expenditure
High voltage lines/cables	25.3%
Low voltage lines/cables	40.2%
Distribution transformers	34.4%

7.1.3 Assets added to the network to address location specific growth in demand

Assets added to the network to address location specific growth relates to the investments to address existing high-capacity assets that are forecast to reach their capacity limit. These investments tend to be of a larger order of magnitude than the individual investments to address non-specific growth. The three main asset investment groups considered to be location specific are:

- investments to build new or augment existing sub transmission network
- investments to build new or augment existing zone substations
- investments to build new or augment existing distribution feeders.

To determine investment into the location specific assets, existing Evoenergy planning policies have been considered to ensure that the current levels of safety, security and reliability area are maintained. Table 7 details the planning rules used for each asset type.

Table 7 Planning rules for asset types to address location specific growth

Asset type	Security Standard	Planning Limit
Sub-transmission line	N-1	50% POE forecast exceeds continuous rating >1% for 88 hours annually 50% POE forecast exceeds continuous rating >20%
Zone substation	N-1	50% POE forecast exceeds 2-hour emergency rating
Distribution feeder	N	75% thermal rating where 2 or more feeder ties share load 50% thermal rating where only 1 feeder tie available (N-1/N)% where N is number of feeders in parallel 100% or less of thermal capacity pending size of tie 100% for no tie (radial line)

To determine the loading on assets, a disaggregation model was developed to convert the network level maximum demand into zone substation specific maximum demands. The disaggregation model works by taking historic demand at each zone substation and determining how much each substation contributed to the total maximum demand.

A non-coincidence factor was then calculated, based on each substation's contribution to network maximum demand as compared to the stations own maximum demand. With the coincidence and non-coincidence factors determined for each substation, the population weighting for each substation was then calculated, based on the number of customers that each substation supplied.

With these three coefficients, the Treasury population forecast, and the network maximum demand forecast, the zone substation maximum demand for each substation is able to be determined for each year in the forecast period. Where a load transfer is projected or a new substation is established to offload another substation, it is treated as a population transfer in the model.

After the forecast has been disaggregated to the zone substations the load is then slightly increased at the zone substations which will be responsible for supplying the future charging stations for the future fleet of electric buses in Canberra.

With zone substation maximum demands now forecast it is possible to estimate if and when the planning limit in Table 6 is reached for each zone substation. In each year where a limit is forecast to be reached an investment to either offload the substation or augment it with additional capacity is proposed and the forecast model is updated.

To estimate when distribution feeder changes are required based on capacity the model uses the zone substation forecasts. The model assumes that all feeders are loaded evenly and conservatively assumes that all feeders can be loaded to a maximum of 75 per cent of the thermal rating of 6.3MVA. When the zone substation load exceeds the feeder limit (6.3MVA x 75 per cent x the number of feeders), an additional feeder is added to the year prior to the load exceeding the limit.

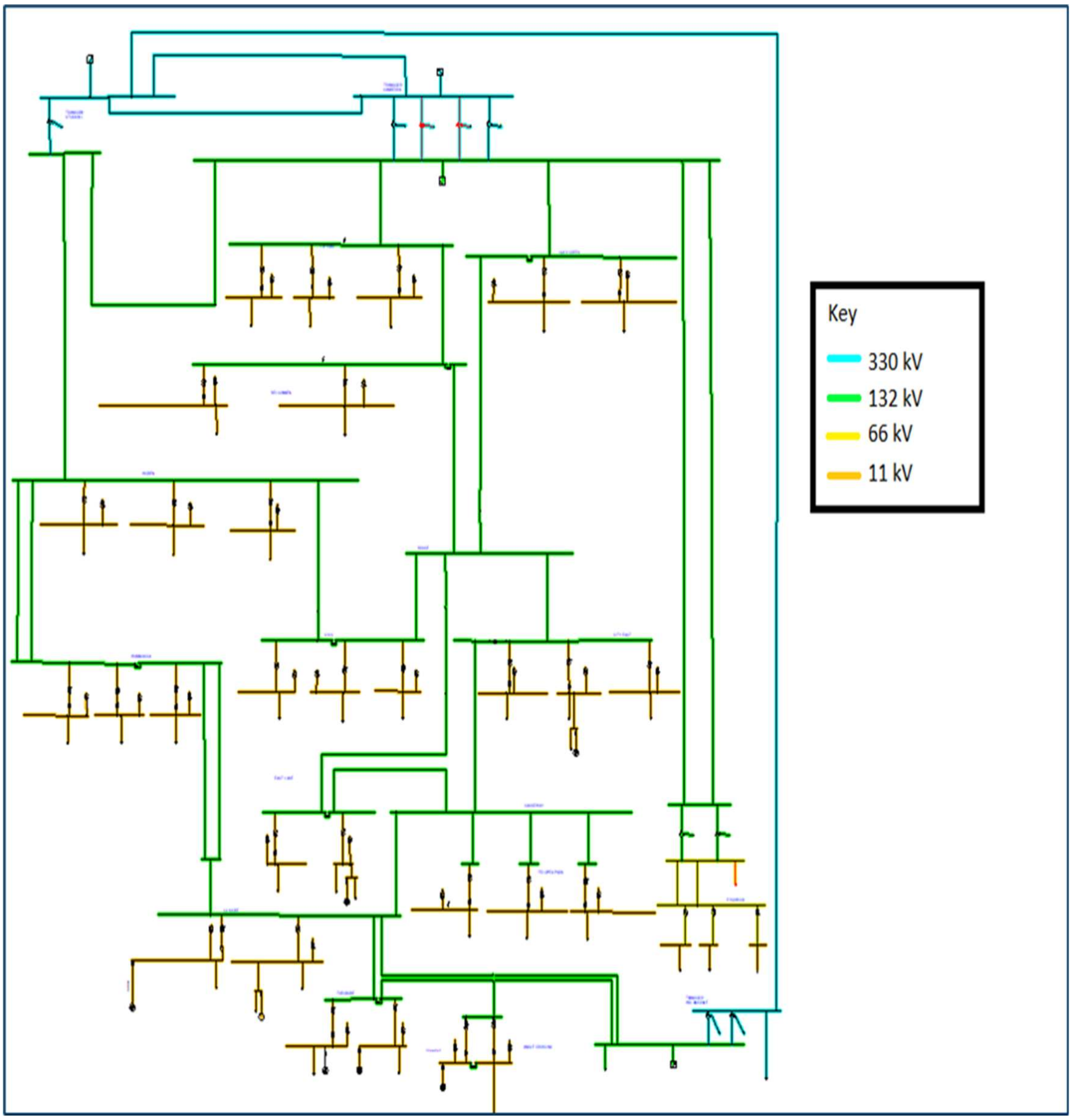
To estimate when sub-transmission augmentations are required, Sincal simulations are completed using the disaggregated loads at the zone substations. Figure 42 shows the Evoenergy sub-transmission network and zone substations with loads at the commencement of the Sincal modelling in 2021.

The model is then updated each year to reflect the changing demand at each zone substation and changes in equipment present in the network. For example, when Fyshwick is decommissioned in 2023, the loads at Fyshwick are transferred to East Lake and the Fyshwick equipment is taken out of service.

The output of the Sincal simulations is the loading on each sub transmission line and the percentage of the loading compared to the thermal rating of the line.

Where a line is identified as exceeding 50 per cent of its thermal rating it is investigated further to identify if the continuous rating will be exceeded by 20 per cent when an N-1 contingency occurs. Every year post the 50 per cent exceedance is checked until either the end of the forecast window is reached, or a breach of the planning limit is identified. Where a breach is identified an investment to add an additional sub-transmission line is recommended.

Figure 42 Evoenergy network depicted in 2021 in Sincal



After all three models have been checked, another check is performed to identify if investments of one type impact the investments of another. If a case is identified where there is an impact, for example a zone substation offload to another substation that also needs new feeders, the works are timed to occur together if possible and scheduling is done to avoid duplication (for example not building 2 lines when one may suffice).

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Based on the results of the network modelling, the investments shown in Table 8 were identified.

Table 8 Forecast location specific investments identified in base case

Year	Investment	Estimated cost ($m)
2022	Completion of the Molonglo battery station including first sub transmission line	13.7
2025	Install 3rd Transformer at Gold Creek zone substation	6.2
2027	Convert Molonglo battery station into zone substation by adding additional sub transmission line, transformer and feeders, plus offload more of Woden zone substation to Molonglo	17.48
2029	Add third transformer to Molonglo zone substation and more feeders and further offload Woden zone substation to Molonglo	10.48
2035	Establish new zone substation (ZS1) including new sub transmission lines, two transformers and multiple distribution feeders Re-balance loads between Woden, Molonglo and new ZS1 zone substations	41.66
2035	Install 3rd transformer at East Lake zone substation	6.2
2036	Construct new distribution feeder out of East Lake zone substation	2.9
2038	Construct two new distribution feeders out of City East zone substation	5.8
2038	Construct two new distribution feeders at East Lake zone substation and transfer load from Telopea Park zone substation to East Lake	5.8
2039	Construct two new distribution feeders at Civic zone substations	5.8
2039	Construct two new distribution feeders at Latham zone substations	5.8
2040	Construct new distribution feeder out of East Lake zone substation	2.9
2040	Construct new distribution feeder out of Gold Creek zone substation	2.9
2040	Construct two new distribution feeders at ZS1 substations	5.8
2041	Construct two new distribution feeders out of City East zone substation	5.8
2042	Build new sub transmission line between Canberra Terminal Station and Latham zone substation	7
2042	Construct two new distribution feeders out of Belconnen zone substation	5.8
2043	Construct new distribution feeder out of East Lake zone substation to offload East Lake zone substation to City East zone substation	2.9
2043	Construct two new distribution feeders out of Latham zone substation	5.8
2044	Construct new distribution feeder out of Gold Creek zone substation	2.9
2045	Install 3rd transformer at Belconnen zone substation	9.1

7.1.4 Assets added to the network to address location non-specific DER

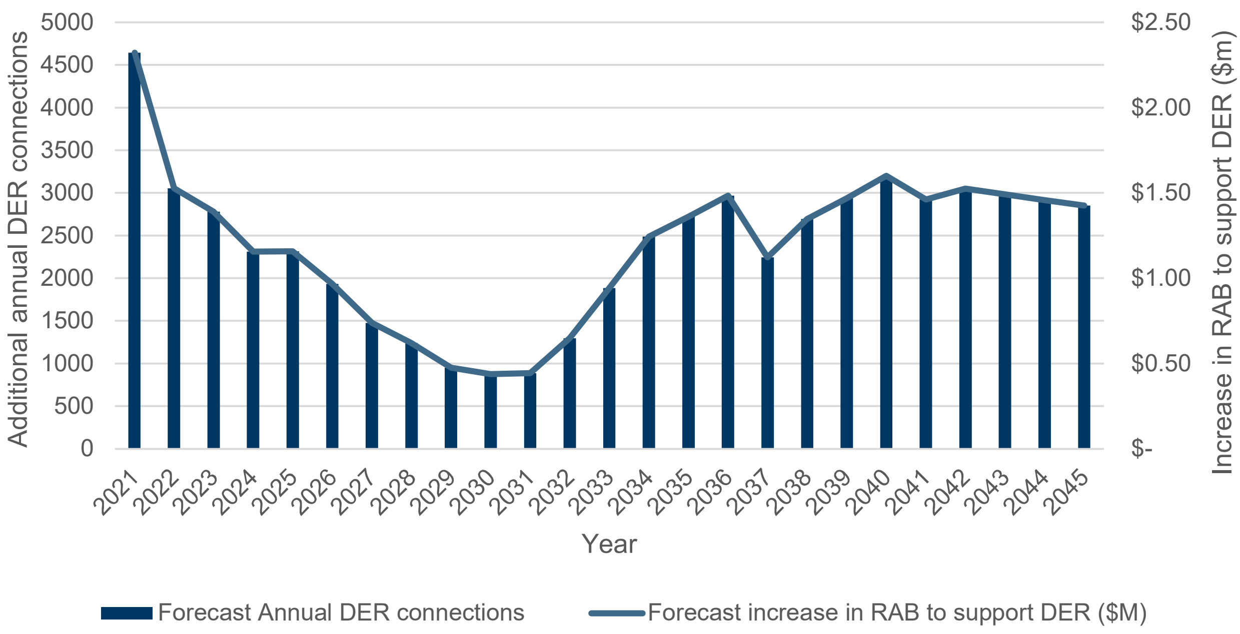
With the rise of DER (in most cases roof top PV) in the distribution network there are growing challenges with enabling the connection of DER and ensuring that existing supply quality requirements continue to be met. Through discussions with Evoenergy it was determined that there are a number of approaches that can be applied to address these issues:

- Evoenergy has already implemented the use of distribution transformers with on line tap changers (OLTC) in locations where all customers have DER
  - Evoenergy advised that this had been relatively successful in mitigating supply quality issues, but estimated that this approach would cost around $100,000 per 200 customers with solar

- Evoenergy is planning a trial of DER with batteries to investigate the use of charging/discharging to address supply quality issues
    - use of this technology to address DER supply quality related issues has not currently been tested, may require investment from customers (rather than the network) and may require new regulatory frameworks to be developed for coordinated control of devices it is unlikely that this technology will be considered as part of the RAB and has been excluded
- introduction of new DER standards - in 2020 AS4777 (the standard for solar inverters) was updated to define default control modes for inverters
    - these default settings have been shown to improve the supply quality performance of inverters (however, case studies of large clusters of these inverters have not as yet been undertaken in an installed environment)
    - it is anticipated that use of the newer inverters will largely address the supply quality issues associated with DER
    - if these inverters are used in combination with distribution transformers with OLTC it is expected that even greater performance would be achieved and less of the OLTC transformers would be required.

For the base case, GHD has adopted the worst-case outcome to determine the upper limit of costs, which is to use a cost of $100,000 per 200 customers with solar. Figure 43 shows the level of investment required based on the proposed method of addressing power quality issues caused by DER.

Figure 43 ***Forecast increase in RAB based on customer DER connection***



The majority of the investment required to address supply quality issues cause by DER is anticipated to occur in the areas where new low rise housing development is expected to take place. This is primarily because of high energy star rating requirements on new houses and the practical roof space available and ease of connection for a free-standing house, compared to an apartment building. As most of the growth in free standing houses is expected in the Woden/Molonglo and Gold Creek areas, it is anticipated that these are the locations where the expenditure will be required.

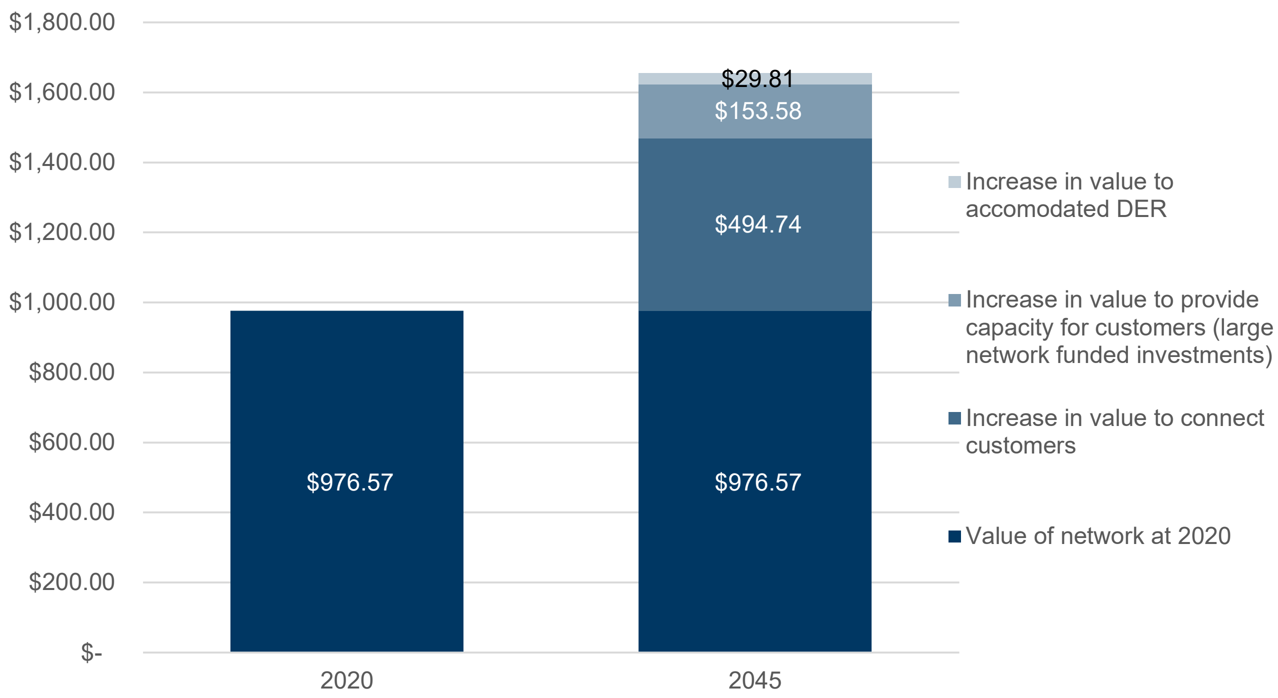
There will be some growth in DER in existing housing areas, but that growth is typically slower than the growth observed when a new estate is developed. Investments to address supply quality issues that arise in areas already developed will be addressed in a case-by-case basis.

It is not anticipated that any large-scale DER on commercial buildings (warehouses, factories, data centres, hospitals etc.) will require investment in supply quality mitigation. Most large commercial buildings typically have their own transformer on site that does not supply any other customers, so any power quality issues that arise will need to be addressed by that customer within their own network.

7.1.5 Drivers for increased RAB

The base case demand forecast will require investment of an additional $678 million in the network to 2045 (up from the 2020 valuation of $1,654 million. The relative magnitude of the growth in the various segments of the network are shown in Figure 44 below.

Figure 44 Change in value of the distribution asset base 2020-2045, $ million



The main driver for investment in the RAB for Evoenergy is the forecast growth in demand. The investment in the network to address the supply quality issues due to the increase in DER penetration is significantly smaller than the investments to address growth in demand. Figure 46 shows that peak demand current occurs at around 6:30-7:00pm and is forecast to remain at that time of day throughout the period modelled. Figure 45 also shows that the most significant growth at the peak demand time is in the residential demand group which is primarily driven by the increase in customer connections caused by population growth.

Very late in the period there is also some growth in the passenger ZEV category. However, that growth is only at a small number of substations (Wanniassa, Woden/Molonglo and Belconnen areas) which, coupled with the growth in population, triggers some rebalancing of load in the Woden/Molonglo area.

Figure 45 Projected 50POE peak demand (MW) – by category

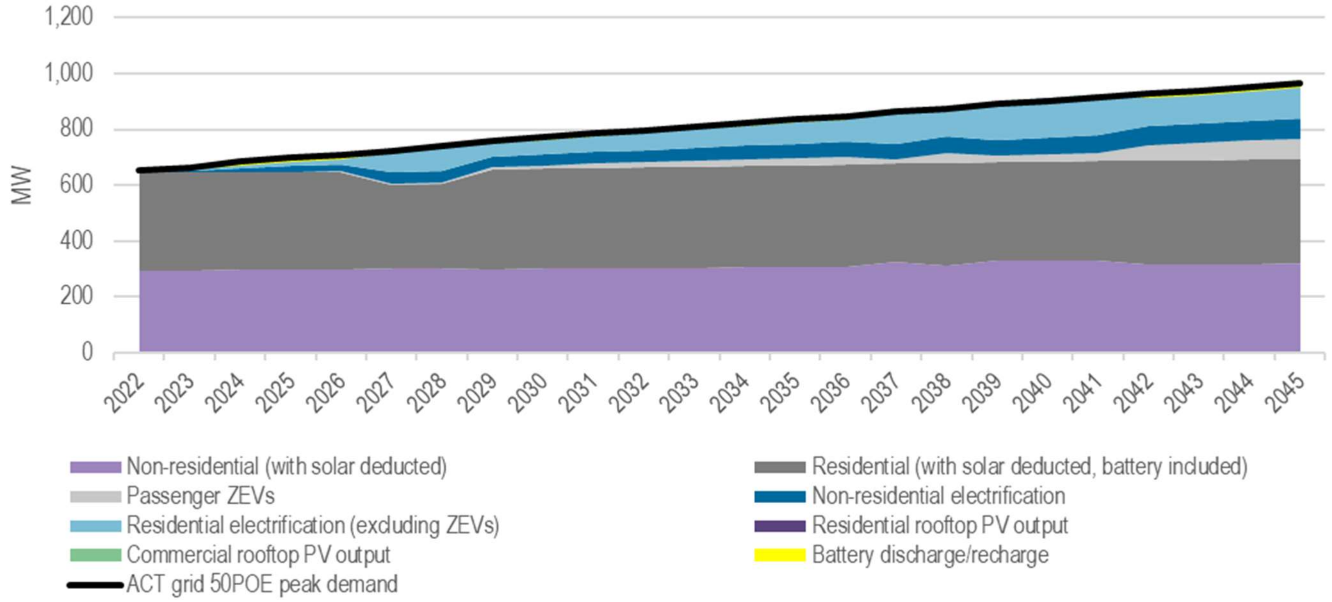
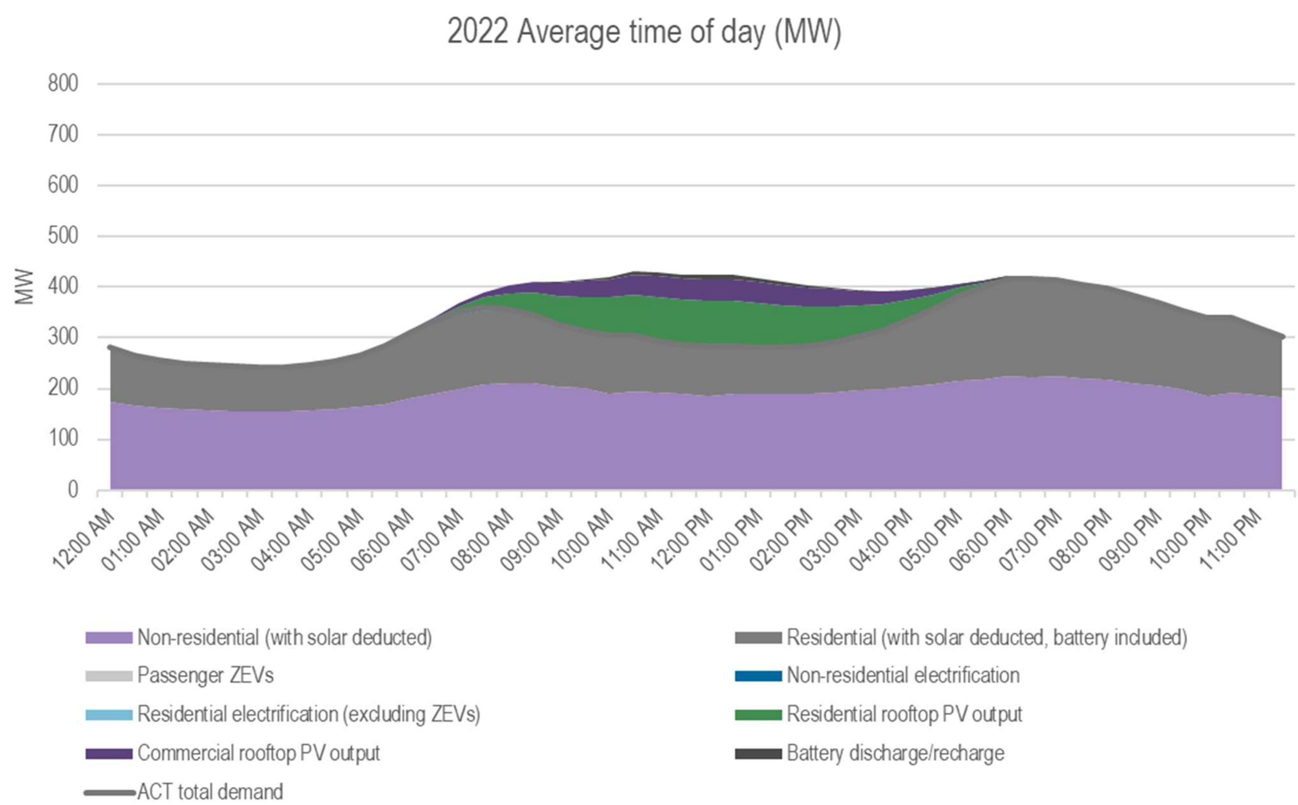


Figure 46 Average time of day demand (MW) – for selected years



7.2 Constraints to supporting net zero emissions Pathway

There are no insurmountable technical constraints to supporting a net zero emissions future. It has been shown that the combination of renewable generation with both renewable storage and battery storage using grid forming inverters can satisfactory supply large networks including the provision of ancillary services such as frequency control. This was demonstrated when South Australia’s Yorke Peninsula transmission network temporarily became an electrical island in November 2019 and was successfully supported with renewable generation and batteries.

The main barrier to reaching net zero emissions is an economic one. With new generation being installed in locations that were not electrically designed for generation, some reinforcement of the network may be required, in addition to the cost of the generators themselves. In addition to reinforcement costs to enable the generators to connect, if the installation of renewable generation leads to traditional synchronous generators being taken out of service (or decommissioned), the ancillary services that those generators provide such as frequency control and inertia will need to be provided by other machines.

This can lead to high installation costs for equipment such as synchronous condensers.

New sources of generation required to facilitate net zero emissions could be located in the ACT or could be remote and supply the ACT via the existing transmission connections. If more of the generation is located within the Evoenergy distribution network there is an opportunity to reduce future augmentation costs, provided effective strategies are put in place to maximise the benefits of local generation. However, even if augmentation is still required there are no technical barriers to providing sufficient secure, safe reliable energy in the ACT to meet the growing demands.

Any further augmentation that would be required would proceed through the existing processes, defined by the AER.

By undertaking the transition away from gas heating and internal combustion engine transportation and moving to electric alternatives, additional generation resources may be required. The addition of the extra load can also lead to additional investment in the network infrastructure to transmit the energy from generators to those new loads.

Essentially, the technology required to achieve a net zero emissions future already exists, and as the technologies become more mainstream, more efficiently produced and have larger capacities, the price is expected to reduce and bottle necks will decrease.

Careful planning with network businesses and proponents for the targeted placement of batteries and DER (to the extent allowed for in the NER) can create opportunities to reduce network augmentation in the future.

8. Electricity retail bill impacts

This Chapter provides a network analysis of the electricity retail impacts. ACIL Allen's retail model was used to project ACT electricity retail prices (in cents per kWh) by customer type over the modelling horizon. The key components of the retail price are shown in the formula of: *Retail price = wholesale component + network component + retail component.* Unless otherwise stated, 'years' refers to financial years ending 30 June.

Key sources of data used as inputs to the retail model include:

- wholesale cost inputs from *PowerMark* (ACIL Allen's model of the wholesale electricity market) projection of wholesale electricity prices
- energy requirements and peak demands from ACIL Allen's electricity demand forecast for the ACT for residential and non-residential customers
- renewable scheme costs – key inputs include published values for the LRET and SRES and ACIL Allen projections of the uptake of small-scale systems and LGC prices
- other costs including ancillary services costs and NEM fees – sourced from AEMO
- network losses – sourced from AEMO
- network costs from ACIL Allen's network tariff model
- retail costs – benchmarked against regulator reports
- assumed energy consumption by customer type – sourced from the electricity demand forecast for the ACT.

8.1 Wholesale component

PowerMark projected wholesale prices in the NSW NEM region have been used to estimate the wholesale cost component of the retail bill. ACIL Allen maintains a quarterly Reference case projection of the NEM, which is modelled using ACIL Allen's in-house simulation models, *PowerMark* and *GasMark*.

We have used our September 2021 Reference case as the starting point in this engagement. The Reference case has been normalised for weather and plant outage effects and represents the median or 50th percentile of the distribution of possible annual pool price projections. The annual electricity price distribution exhibits positive skewness (long right-hand side tail). Lower annual pool price projections are associated with cooler summers/warmer winters/lower outage rates and higher annual pool price projections are associated with hotter summers/colder winters/higher outage rates.[24]

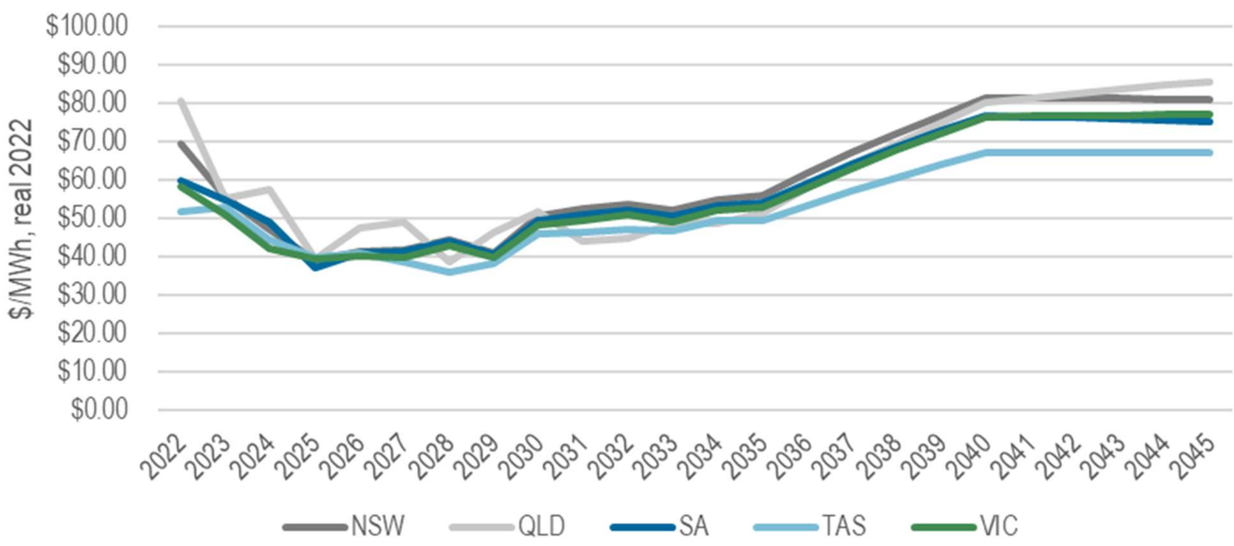
[24] Lower annual price projections are less volatile and cluster close to the median projection as they are limited by the underlying marginal costs of the various plants operating in the market. Higher annual price projections are more volatile and spread over a longer tail above the median projection, due to less effective competition in periods of higher demand and/or more plant outages (limited only by the market price cap).

When generators and retailers enter contracts, they are more likely to price them at prices above the median price, typically at or above the mean. The extent that contracts are priced above the mean depends on the relative risk appetite of participants. Stand-alone retailers are thinly capitalised and have a lower risk appetite than generators. Therefore, when participants contract their output forward, it is reasonable to add a premium to the median prices to reflect the premium that contracts would be sold for in the market.

Figure 47 below shows projected time-weighted prices by NEM region under the median view. An additional uplift to the time-weighted price has been applied to include the cost of hedging for each customer type. One component of the uplift represents the contract premium that retailers pay to hedge their customer load (as explained above) and the other component represents the load shape of the customer.

For example, the load of a residential customer has a lower load factor, with most of the consumption falling during high demand periods. This means that the residential customer's load will be more costly per MWh to supply because of higher and more volatile wholesale spot prices during these periods. This is compared to a large commercial customer with a typically flatter load profile, which would have a lower cost per MWh to supply.

Figure 47 Projected time weighted prices by NEM region ($/MWh, real 2022)



Source: ACIL Allen

NEM fees and ancillary services costs are also added to the wholesale component. These costs are sourced from the latest AEMO data and assumed to remain constant in real terms over the projection period. NEM fees and ancillary services are estimated to be around $1/MWh, which is around one per cent of the total wholesale component.

8.2 Network component

The network component comprises of transmission; distribution; jurisdictional schemes; and network metering costs. ACIL Allen has projected annual regulated revenues based on the building blocks method. Network Use of System (NUOS) tariffs by customer type have been estimated using the expected weighted average revenue for the regulatory year 2021-22 in Evoenergy's pricing proposal and projected forward based on these weightings.

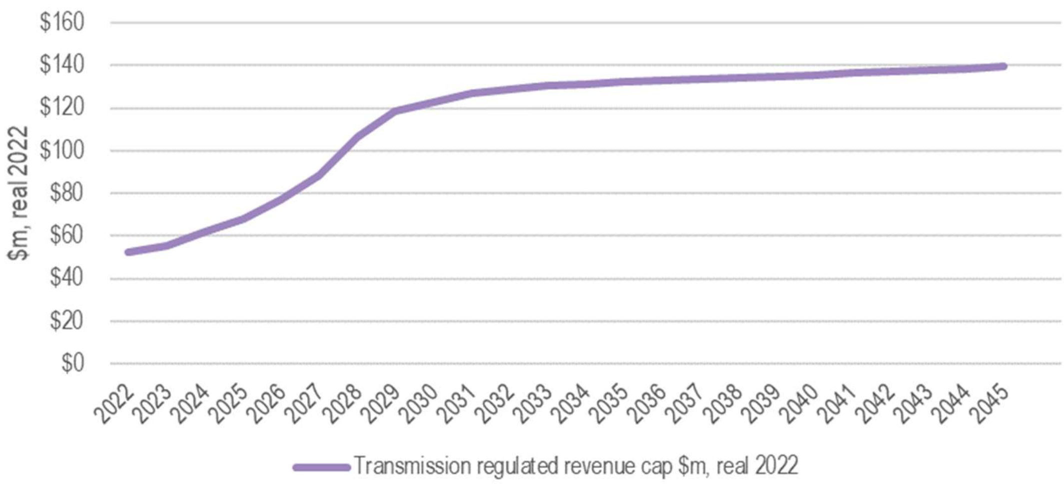
8.2.1 Transmission

ACIL Allen has projected annual regulated revenues for transmission based on the building blocks method. ACIL Allen has incorporated GHD's projected capital expenditure for Evoenergy's sub-transmission business into this analysis.

Figure 48 below shows projected annual revenues recovered by Evoenergy through Transmission Network Use of System (TUOS) tariffs. Projected TUOS revenues also assume significant capital expenditure by TransGrid (transmission network company for the broader NSW region) for network augmentation under the base case associated with the ISP actionable projects detailed in Table 8.

Projected revenues for TransGrid are allocated to the ACT retail price using the proportion of ACT electricity consumption relative to NSW electricity consumption.

Figure 48 Projected annual revenues for transmission ($ million, real 2022)



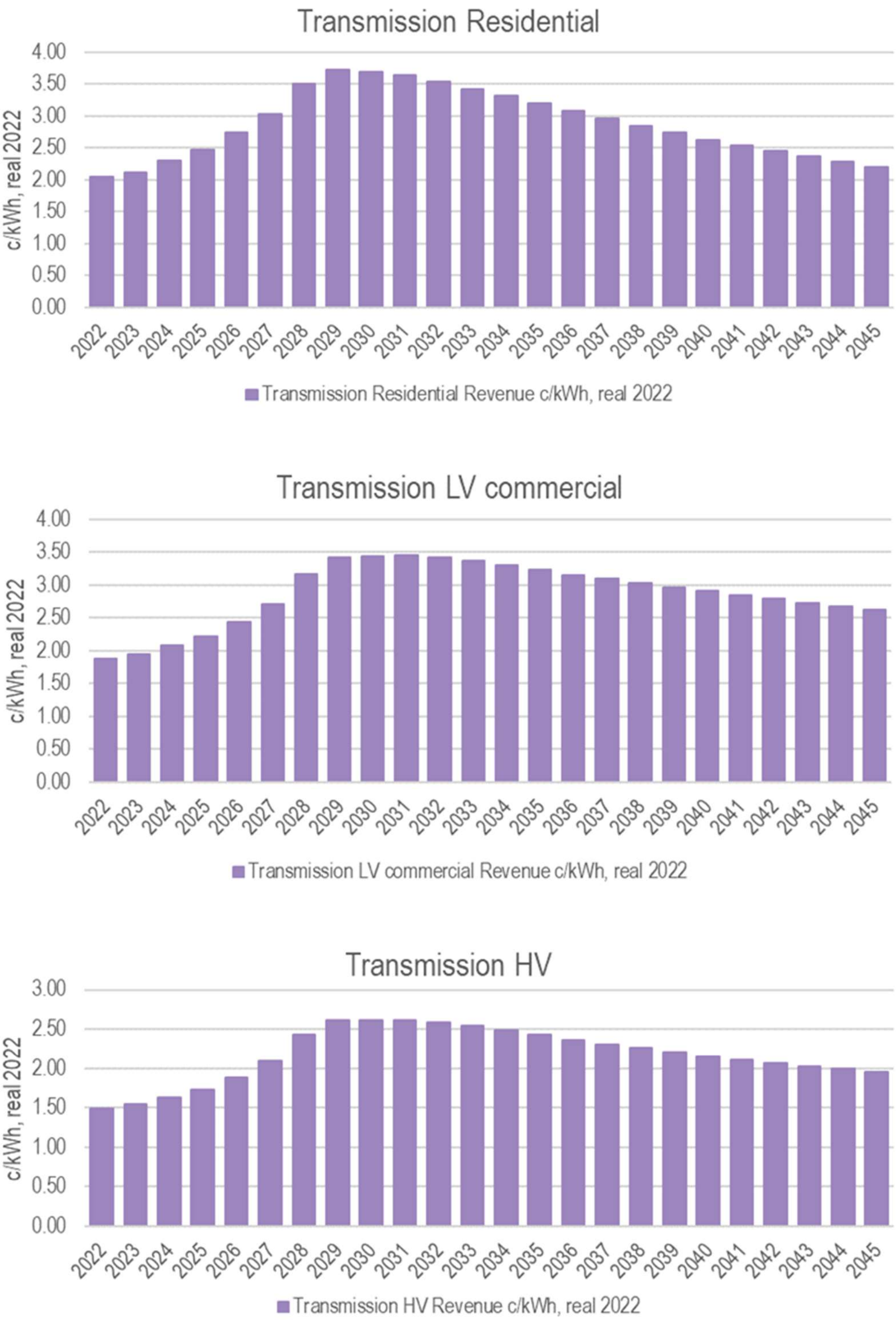
Source: AER, TransGrid, Evoenergy, ACIL Allen

Evoenergy estimates proposed TUOS prices for 2021-22 would result in the recovery of around $52.4 million with the following implied weightings by customer type:

- Residential 43 per cent
- LV commercial 46 per cent
- HV 11 per cent.

Projected TUOS tariffs by customer type are shown in Figure 49 below and assume the weightings above do not change significantly from year to year. Projected TUOS tariffs decline in real terms after 2030 due to the projected rate of increase in electricity consumption outstripping the projected rate of increase in total (real) regulated revenues for transmission.

Figure 49 Projected TUOS tariff, by customer type (c/kWh, real 2022)

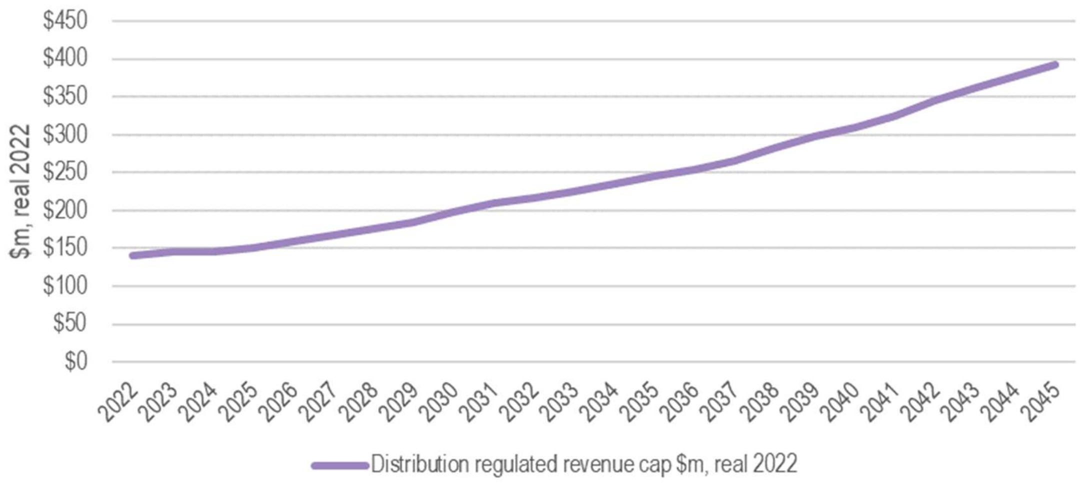


Source: Source: AER, Evoenergy, ACIL Allen

8.2.2 Distribution

ACIL Allen has projected annual regulated revenues for distribution based on the building blocks method. ACIL Allen has incorporated the projected capital expenditure estimated by GHD (as discussed in Chapter 7) into this analysis. Figure 50 shows projected annual revenues recovered by Evoenergy through Distribution Network Use of System (DUOS) tariffs.

Figure 50 ***Projected annual revenues for distribution ($ million, real 2022)***



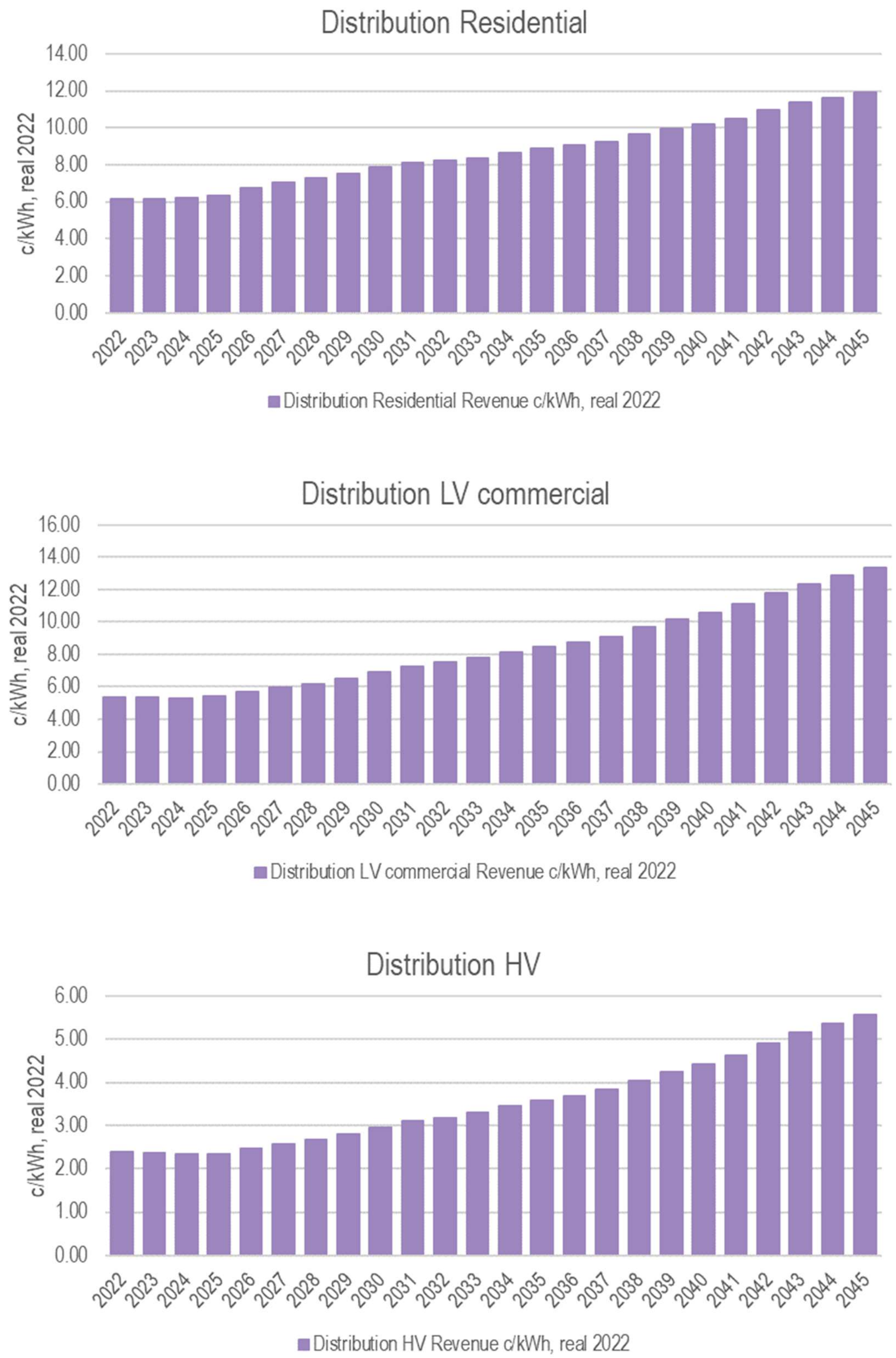
Source: AER, Evoenergy, ACIL Allen

Evoenergy estimates proposed DUOS prices for 2021-22 would result in the recovery of around $146.8 million with the following implied weightings by customer type:

- residential 46 per cent
- LV commercial 48 per cent
- HV six per cent.

Projected DUOS tariffs by customer type are shown in Figure 51 below and assume the weightings above do not change significantly from year to year. Projected DUOS tariffs increase in real terms across the projection period due to the projected increase in total (real) regulated revenues for distribution.

Figure 51 Projected DUOS tariff, by customer type (c/kWh, real 2022)



Source: AER, Evoenergy, ACIL Allen

8.2.3 Jurisdictional schemes

Projected hourly wholesale electricity spot prices in NEM regions NSW, Victoria and South Australia from *PowerMark* have been used to calculate large FiT payments in relation to projecting the impact of ACT continuing to purchase 100 per cent renewable electricity.

Projected payments which assume FiT contracts expire after 20 years, are shown in Figure 52. At the request of the client, we have included a third auction in 2025 to acquire additional renewable electricity, which is assumed to be two x 200 MW wind farm in NSW (while twice the quantum suggested, the additional capacity is necessary to meet the commitment).

Over the period to 2029, projected large FiT payments remain at current high levels as projected wholesale prices are expected to continue to decline as the result of significant amounts of new supply entering the market.[25]

From around 2029, projected wholesale electricity prices rise with the closure of several coal fired power stations and growth in demand from projected ZEV uptake, which results in declining large FiT payments. As indicated at Figure 52, large FiT payments are projected to continue to decline and by 2036 are projected to become negative (resulting in net revenue to the ACT Government/Evoenergy/customer) as projected wholesale spot prices rise because of further coal power plant closures and demand growth.

From around 2040 projected wholesale prices are capped at the long-run cost of new entrant supply.

Figure 52 Projected large feed in tariff payments (c/kWh, real 2022)

Note: FY2022 estimate is Evoenergy's estimate published in their 2021-22 pricing proposal.

Source: ACIL Allen analysis based on the median or 50th percentile view, https://www.environment.act.gov.au/energy/cleaner-energy/renewable-electricity-costs-and-reviews, and Evoenergy Pricing Proposal 2021-22

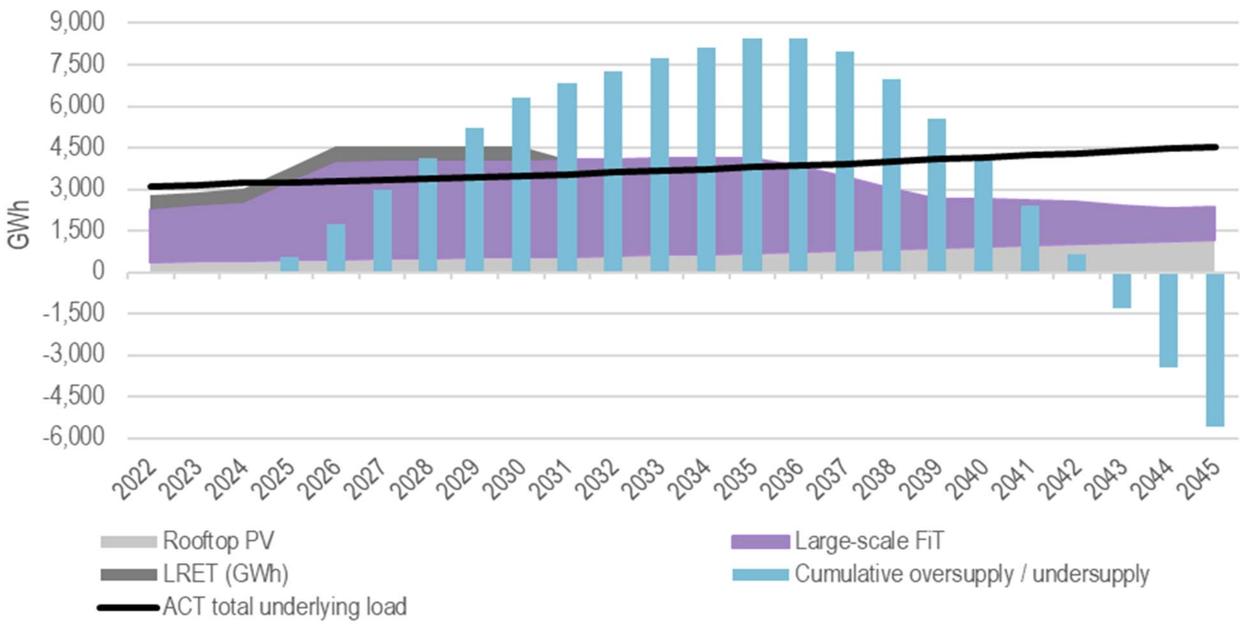
[25] Assumed new supply from renewables and large-scale storage proposed by state-based schemes such as the NSW Roadmap.

While the base case incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable, the projections show that the ACT will fall below the 100 per cent renewable mark from 2037, declining to around 55 per cent of underlying demand by 2045 as shown in Figure 53.

On this basis, the government could need to factor in a further auction of renewable electricity around 2035-36. However, under the current policy renewable electricity in excess of 100 per cent target is 'banked' with credits carrying over to future years. These credits are carried forward and built into the cumulative oversupply/undersupply blue bars at Figure 53.

These credits offset the need for additional purchases up until 2043.

Figure 53 ***Projected contribution by category to 100% renewable energy (GWh)***



Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis:

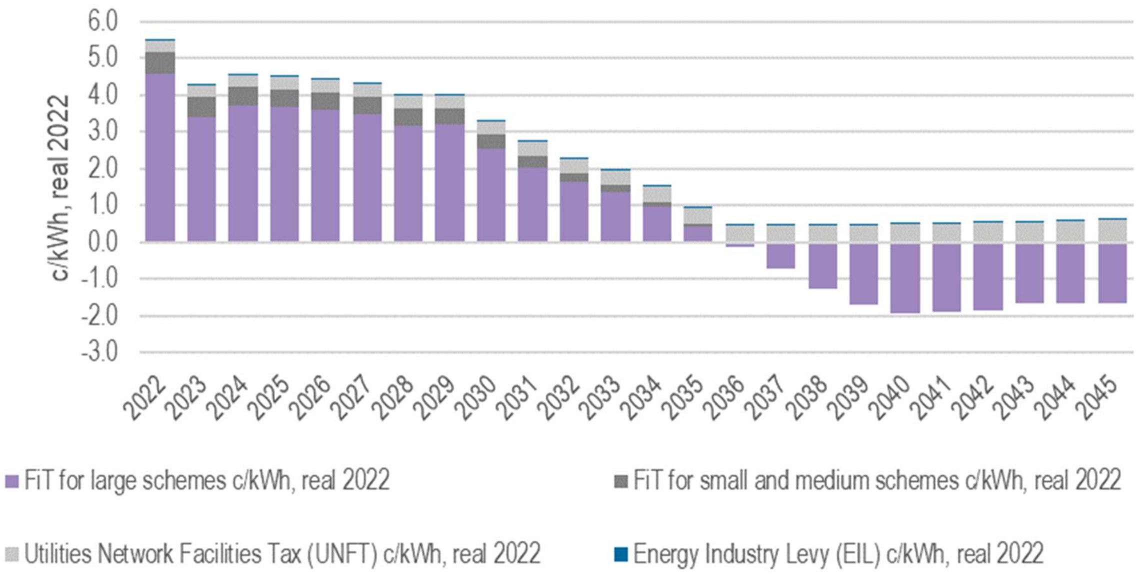
Furthermore, the NEM is projected to source more of its generation from renewables over time – increasing from around 30 per cent currently to a projected 70 per cent by 2045 which may also largely offset the continuing need to purchase 100 per cent renewable electricity (it is noted that published methodology for calculating the 100 per cent commitment[26] does not take into account how 'green' the NEM is).

Given these considerations, an additional purchase of 100 renewable electricity in 2036 has not been factored into the base case. We will consider the need for additional purchases as part of the scenario analysis, given changes in underlying load.

Figure 54 below shows the total cost of jurisdictional schemes, including large FiT, small FiT, Energy Industry Levy and the Utilities Network Facilities Tax.

[26] *Climate Change and Greenhouse Gas Reduction (Renewable Electricity Target Measurement Method) Determination 2020* **https://www.legislation.act.gov.au/di/2020-17/** accessed 26 November 2021

Figure 54 *Projected cost of jurisdictional schemes (c/kWh, real 2022)*

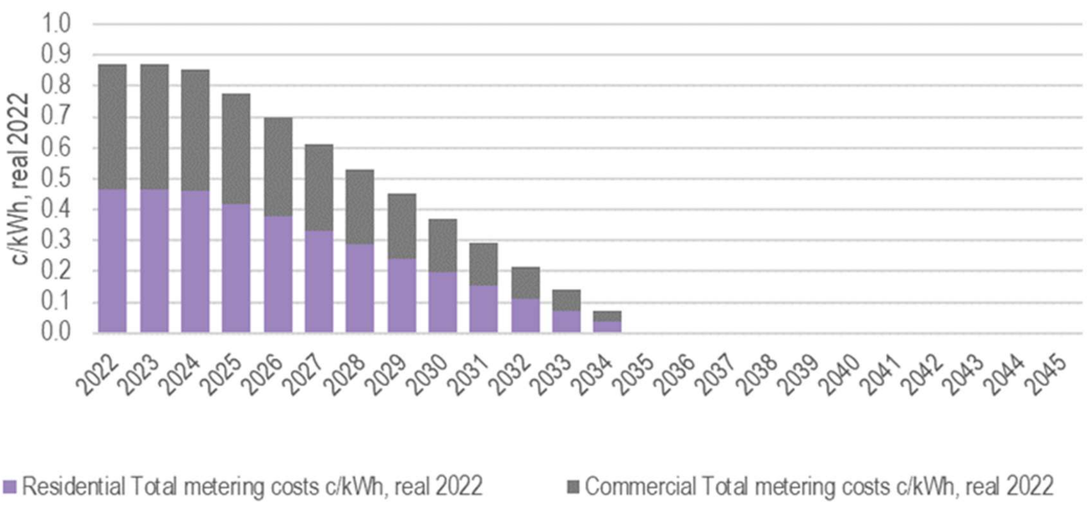


Note: FY2022 estimate is Evoenergy's estimate published in their 2021-22 pricing proposal.
Source: ACIL Allen analysis based on the median or 50th percentile view, https://www.environment.act.gov.au/energy/cleaner-energy/renewable-electricity-costs-and-reviews, and Evoenergy Pricing Proposal 2021-22:

8.2.4 Metering

Metering charges cover the costs associated with Evoenergy's provision of regulated Type 5 and Type 6 metering services.[27] Residential and low voltage commercial customers connected before 1 December 2017 have regulated Type 5 or Type 6 meters, which are subject to price cap regulation. We have estimated projected metering charges using information in AER's Final Decision Metering PTRM for the 2019-24 regulatory control period and Evoenergy's latest pricing proposal. The projections illustrated at Figure 55 assume that Type 5 and Type 6 meters are phased out completely by 2035.

Figure 55 *Projected metering costs (c/kWh, real 2022)*



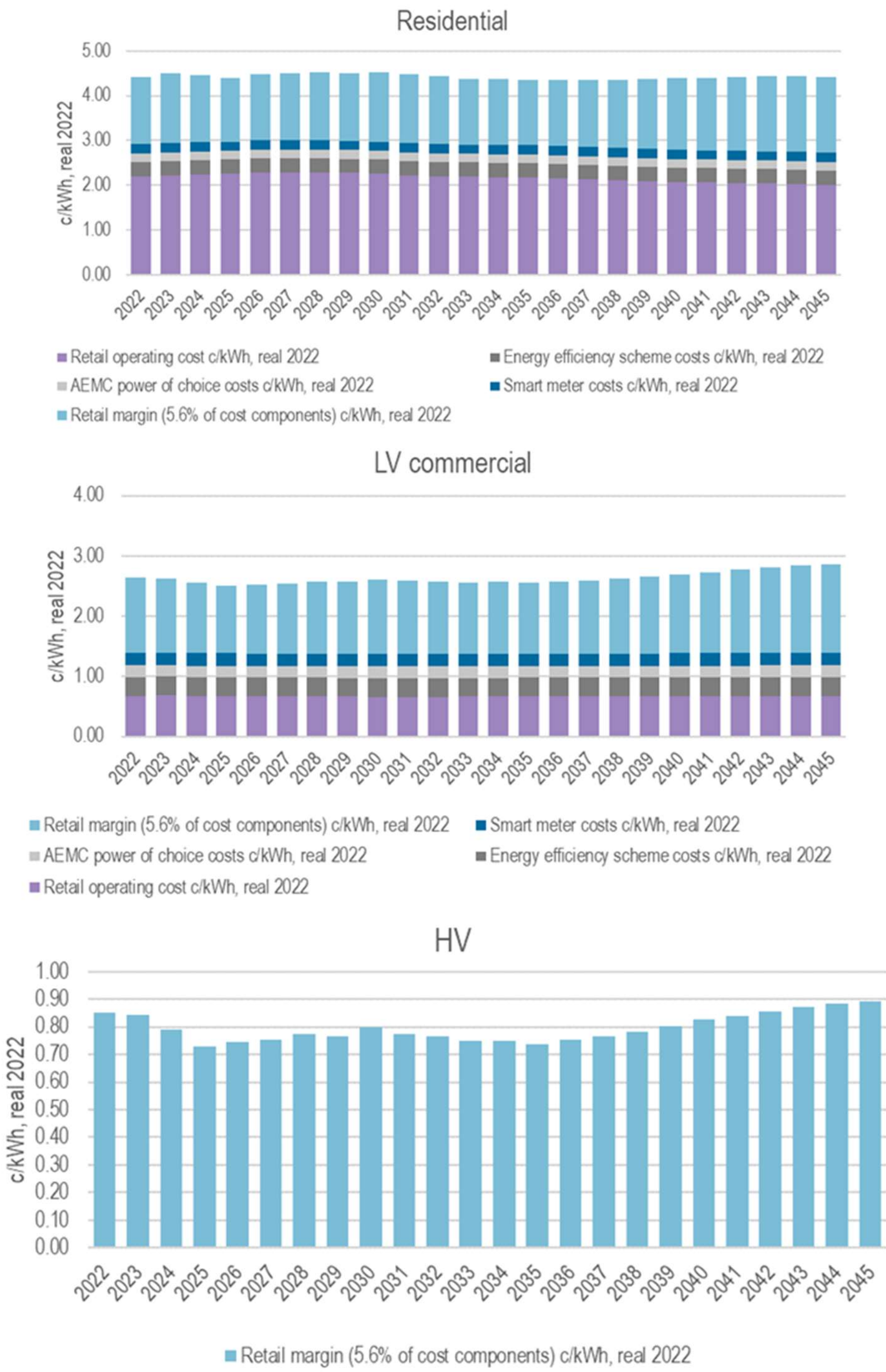
Source: ACIL Allen, AER, Evoenergy

[27] Smart metering costs are factored into the Retail cost component

8.3 Retail component

The retail component illustrated at Figure 56 comprises of residential and LV commercial customers: retailer operating cost; Energy Efficiency Scheme costs; AEMC Power of Choice costs; smart meter costs; and retail margin. The starting estimates for residential customers for 2021-22 were sourced from the Independent Competition and Regulatory Commission's (ICRC's) latest retail pricing report and ACIL Allen assumptions for commercial customers. ACIL Allen assumes the retailer recovers a margin of 5.6 per cent on HV customers.

Figure 56 Projected cost of retail component, by customer type (c/kWh, real 2022)



Source: ICRC, ACIL Allen

8.4 Total retail prices

Bringing together the wholesale, network and retail components discussed in this Chapter, the projected retail prices are shown in Figure 57.

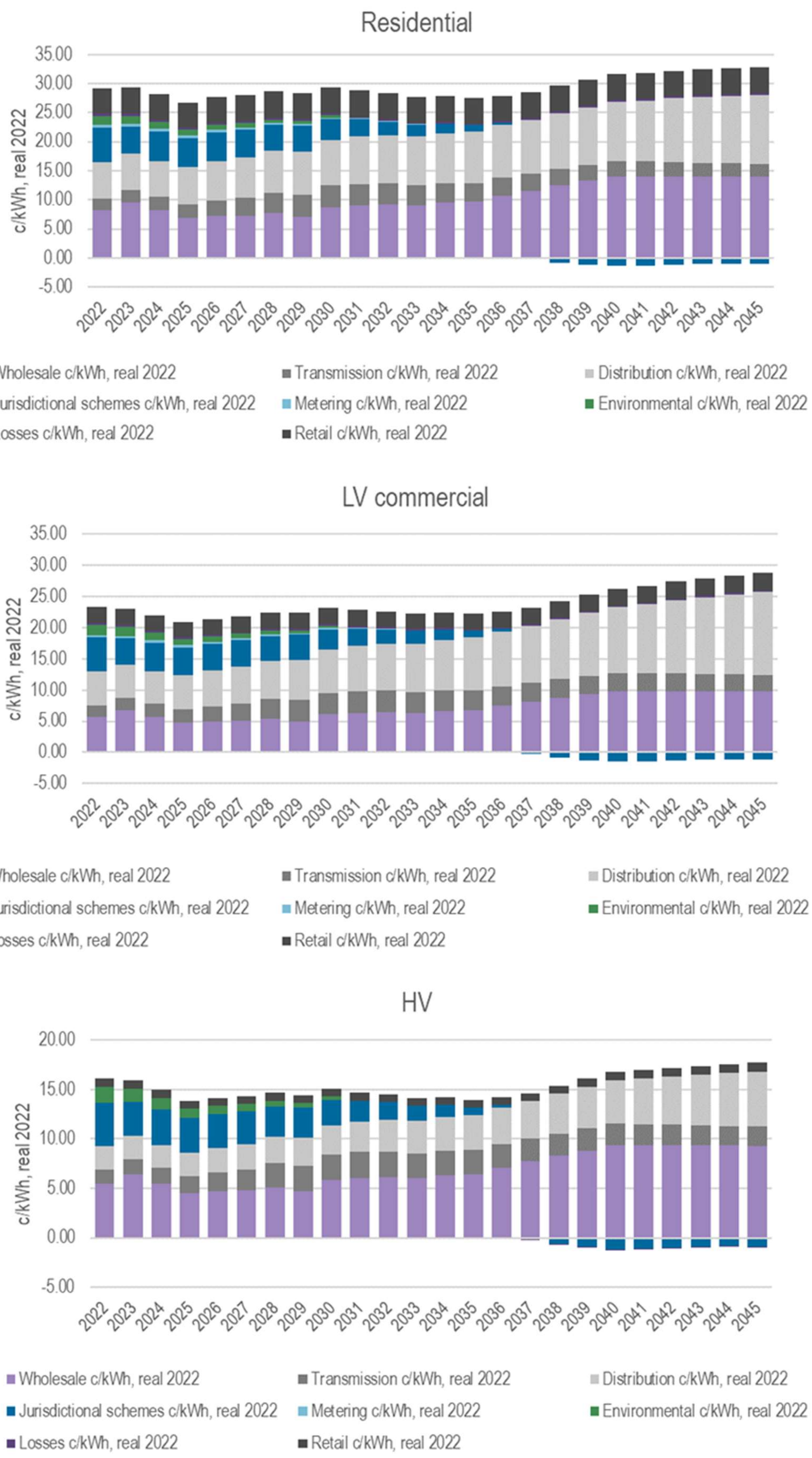
Total retail prices are projected to increase in real terms over the projection period from 2022 to 2045. Over the projection period, real retail prices for residential, LV commercial and HV customers are projected to increase by nine per cent, 19 per cent and five per cent, respectively.

A key driver of the increase is the projected increase in wholesale and distribution network costs, which are partially offset by projected decline in the cost of the large FiT scheme.

The projections by component are discussed further below.

- Wholesale component – is projected to remain at current low levels until around 2029 given the significant amount of new supply assumed to enter the market under state-based schemes.
  - From 2030, the projected wholesale component rises, reflecting the closure of several major coal fired power stations and growth in demand from projected ZEV uptake.
  - From around 2040, projected wholesale prices are capped at the long-run cost of new entrant supply.
- Network component (Transmission and Distribution) – is projected to rise over the period, given projected capital expenditure to support major network augmentations and is largely driven by projected increase in the cost of the distribution network.
- Network component (Jurisdictional schemes) – is projected to peak at current levels and decline over time as projected wholesale prices rise and existing large FiT contracts expire. From 2038, the large FiT is expected to return net revenues to customers.
- Network component (Metering) – is projected to decline over the period to 2035 as legacy meters are replaced by smart meters (which are subject to the contestable market).
- Environmental component – is projected to decline to zero after 2030 as Commonwealth Government schemes (LRET and SRES) end in 2030.
- Retailer component – for residential and low voltage commercial customers, this component is projected to remain fairly constant in real terms, with declining retailer operating costs largely offsetting rising cost of retailer margin. For the high voltage customer, retail costs increase in line with the increase in other tariff components since retail costs for this customer are comprised entirely of the retailer margin.

Figure 57 *Projected retail prices in the ACT, by component, by customer type (c/kWh, real 2022)*



Source: ACIL Allen

8.5 Retail bill

We have estimated projected retail bills for different customers as shown at Figure 58 by multiplying the projected retail price (see Section 8.4 above) by the projected average consumption per customer.[28]

- projected average consumption per customer declines over the period to around 2028 because of the projected increase in penetration of rooftop solar PV
- after 2028, projected average consumption per customer rises as a result of projected increases in the uptake of ZEVs and the impact of the natural gas transition
  - for LV and HV commercial customers, projected average consumption rises from 2024 and 2026 respectively, as a result of the impact of natural gas transition.

Over the period to 2035, projected retail bills for residential, LV commercial, and HV customers declines by five per cent, three per cent and nine per cent, respectively. These trends are as a result of the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes. For residential customers, these declines are offset by projected increases in wholesale and network costs.

Over the period from 2035 to 2045, projected retail bills for residential, LV commercial, and HV customers increase by 25 per cent, 22 per cent and 24 per cent, respectively. These increases reflect the projected increase in wholesale electricity prices and distribution network costs (as reflected in Figure 57).

8.5.1.1 Retail bill using AER customer class

The previous section discussed projected retail bills of Evoenergy's three customer types, namely residential, LV commercial, and HV customers. This section discusses projected retail bills based on AER's customer classification (as requested by the client). Under both classifications, residential customers are identical, while the AER classifies electricity market commercial customers slightly different.

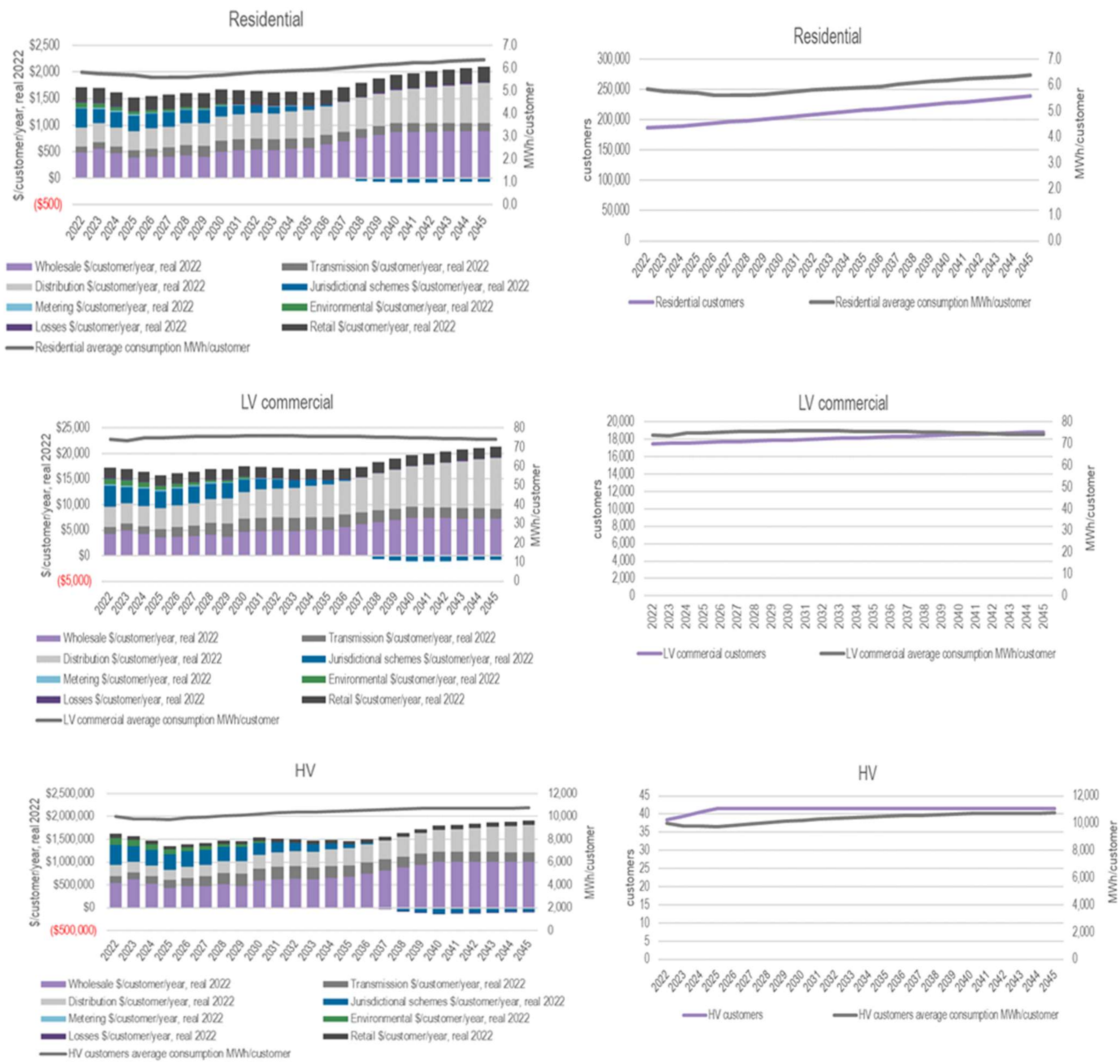
Evoenergy classifies its commercial customers based on the type of network they access, namely a low voltage network or a high voltage network. However, the AER classifies commercial customers based on the following criteria:

- for small business customers based on energy consumption below a predefined upper consumption threshold – in NSW, this upper consumption threshold is 100 MWh per annum
- for large business customers based on energy consumption above the 100 MWh consumption threshold.[29]

Figure 59 shows the projected retail bills for the AER small business and large business customer types, respectively. Since the AER uses the same residential customer classification as Evoenergy, there is no difference from the residential retail bill presented in Figure 58.

[28] Projected average consumption is based on historical consumption and customer numbers by Evoenergy customer class and projected forward using ACIL Allen's demand forecast and other information from this engagement.
[29] Section 5, National Energy Retail Law (NSW) No 37a of 2012, Current version for 20 May 2021 to date (accessed 10 November 2021 at 13:54). The law has been applied in NSW, Queensland, South Australia, Tasmania and the ACT, with some special provisions in particular states.

Figure 58 Projected retail bill (left chart), by component, by customer type ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS); Projected customer numbers (right chart)



Source: ACIL Allen

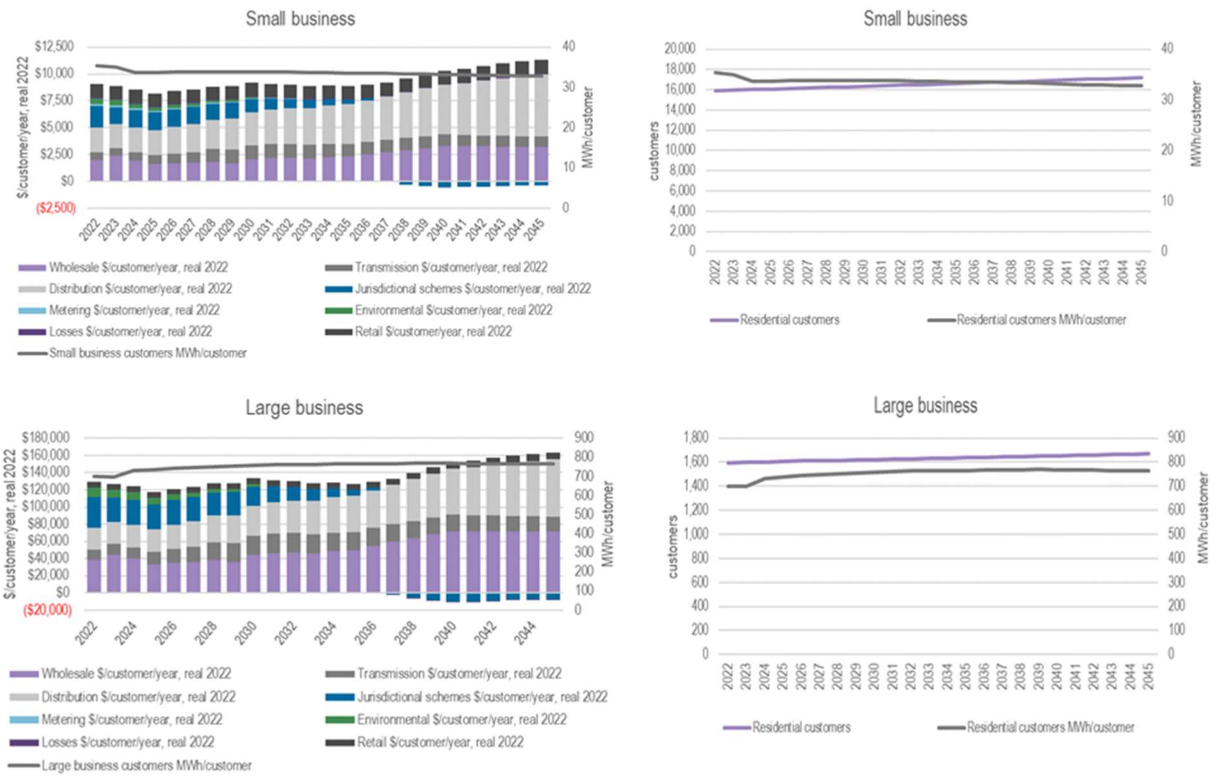
Given the upper consumption threshold for small business customers of 100 MWh per year, the average consumption of small business customers is much smaller than that of LV commercial customers under Evoenergy's customer category. The average projected energy consumption of small business customer ranges between 33 to 35 MWh per annum over the projection period, while the average consumption of LV customer ranges between 73 and 76 MWh per annum. The direct result of this difference is the lower average retail bill for small business customers compared to LV commercial customers.

Part of the LV commercial customers are categorised as large business customers under the AER classification. Therefore, AER's large business customer category includes more customers than Evoenergy's HV customer category resulting in lower average consumption per customer. As a result, the average retail bill of large business customers is smaller than the average HV customer retail bill.

Despite these differences, the projected retail bills for small and large business customers follow a similar pattern as retail bills of LV and HV commercial customers. Over the period to 2035, projected retail bills for small business customers stay relatively stable with only a two per cent decline. Retail bills for large business customers decline by two per cent over this period. These trends are as a result of the projected decline in large FiT payments and costs associated with the Commonwealth Government’s environmental schemes, largely offsetting projected increases in wholesale and network costs.

However, between 2035 to 2045 the retail bills of small and large business customers both increase by 23 per cent. This can be attributed to increased wholesale prices and distribution costs.

Figure 59 ***Projected retail bill (left chart), by component, for business customers ($/customer/year, real 2022) (LHS) and projected consumption per business customer (MWh/customer); Projected customer numbers (right chart)***



Source: ACIL Allen

9. Supporting the net zero emissions pathway

This Chapter provides for insights gained through base case modelling as to the effect of the current ACT Government climate change policies and objectives aimed at delivering a net zero emissions pathway and the impact on the ACT electricity and gas networks.

Understanding these impacts is important to the development and construct of the strategic scenarios to be examined as options to further move and accelerate progress towards net zero emissions.

The modelling work provides the Government has a holistic view of current electricity network capabilities and constraints, and how future changes to natural gas, transport and electricity consumption and generation are likely to impact the network and consumers.

Balancing actions when considering opportunities and constraints is complex, especially as some actions will preclude alternative approaches. For instance, incentives to drive electrification of current gas usage might lead to decommissioning of the network and effectively rule out the development of a green gas alternative (consumers are highly unlikely to undertake the expense of a double conversion – gas to electric back to green gas).

Other actions which appear highly attractive may not offer the best opportunity to bring about transformational change given the relatively small impact they generate in the overall system. Accordingly, it is essential to take a holistic view to determining both impact and return on the investment in actions (whether they be policy, program or regulatory in nature).

9.1 Gas market

The base case projects total gas consumption to decline by approximately 60 per cent (because of both falling consumption per connection and a steady decline in connections from 2023). This represents a steady decline but is a marked change from consumption over the past decade, which has been relatively stable.

That stability has, to a large degree, been driven by new connections. The Government's electrification policy – no gas connections in future stages of greenfield residential developments from 2021-22 and no new gas connections in infill developments from 2023 – is strongly driving the projected decline in gas use.

There is an opportunity to accelerate this decline through placing further policy limitations around new connections or incentivising consumers to adopt higher levels of electrification (i.e., through financial assistance). However, there is a question as to whether this is necessary.

There will be a 'tipping point' where the gas network becomes uneconomic to operate. It will be critical to understand this to determine if further intervention is necessary or whether a 60 per cent decline is close to triggering collapse. As discussed at Chapter 5, a key implication from declining demand is the capacity for future investment and maintenance of the Evoenergy gas network.

The projected decline of 60 per cent will also place pressure on the distribution network in terms of its long-term viability and will have consequences for gas prices. What this means for gas networks and the current regulatory regime will be a key consideration for the more stringent scenarios where deeper cuts for natural gas are expected and the transition to electrification is accelerated. A better understanding of the 'tipping point' will be a key input to policy decisions.

However, there will be some residual gas use by customers unable to electrify. Some industrial customers may need gas as a feedstock or electric equipment options may be limited/unavailable. Biogas or hydrogen may provide suitable low emission alternatives for them.

The alternatives by which biogas or hydrogen are delivered will be subject to a variety of factors including the viability of the gas network and may be site specific including on-site generation. Some residential customers in high-rise/medium density settings may face physical and cost limitations plus strata title challenges in conversion from gas to electricity. Tank gas and offsets may be the only viable solution to address these issues, at least until major building renovations with structural changes occur. There will be negative cost of living impacts for customers who cannot readily move away from the gas network (full gas transition modelling would be required to quantify these impacts).

A further consideration is the extent to which Government wishes to keep the option of actively pursuing a green gas pathway. Moves to rapid and extensive electrification will effectively preclude green gas as an option, especially if they lead to closure/partial closure of the gas network.

9.2 Electricity

Opportunities and constraints in relation to electricity will occur in both the electricity market and the network.

9.2.1 Market opportunities and constraints

We have incorporated several key market parameters into the base case modelling which are discussed below.

9.2.1.1 ZEVs

Between 2038 and 2045 under the base case, passenger ZEVs are projected to be the largest (~20 per cent in 2045) category of electrification in terms of energy requirements. However, prior to 2038 they represent only a small (~1-9 per cent) component. This reflects the projected ramp up in the uptake of ZEVs.

Bringing forward the uptake of ZEVs in the ACT prior to 2038 represents a significant opportunity to pursue the net zero emissions pathway. While initial uptake (say to 2030) will be restricted by the availability of a suitable range of EV choices, recharge options and facilities and inertia in the fleet turnover, the market opportunities beyond 2030 will mature and moves to EVs will be much more the norm.

There are a range of financial incentives and regulatory levers the Government could use to drive stronger uptake of EVs. However, the timing of these will need to be carefully calibrated to the development of the market to ensure demand does not outstrip supply.

9.2.1.2 Household electrification

Under the base case, transitioning households from gas is projected to have a reasonable (~seven per cent by 2045) impact as a proportion of total ACT electricity demand. Similarly, transitioning the commercial sector away from gas is projected to have around a six per cent impact by 2045. As discussed above, the base case projects total gas consumption to decline by approximately 60 per cent by 2045. In effect this is achieved without substantive impact on electricity demand and, as thus, represents a strong return in terms of moves towards net zero emissions. Notwithstanding the caveats in relation to the gas market discussed above, bringing forward gas transition represents an opportunity to deliver the net zero emissions pathway quickly. Accordingly, this is pursued as an option in the scenarios to be modelled. The level and rate of transition needs to be informed by the 'tipping point' issues discussed earlier.

9.2.1.3 Public transport electrification

While the optics of electrification of the Action bus fleet are very strong (a tangible way the Government can demonstrate it is taking the lead), the electrification of the total fleet of buses is projected to have a very small (~one per cent) impact as a proportion of total ACT electricity demand. Similarly, Canberra Light Rail stage 2 is projected to have a very small (<one per cent) impact as a proportion of total ACT electricity demand. As such increasing the number of electric buses and/or developing additional Light Rail are not seen as priorities or key opportunities in driving towards the net zero emissions outcome. Accordingly, these parameters are not adjusted in the scenarios. However, that is not to say they are not important investments from the Government's broader policy perspectives.

9.2.1.4 Household and commercial PV

Under the base case, the uptake of rooftop solar PV (both residential and commercial) is projected to reduce underlying energy requirements by 26 per cent (increasing from 10 per cent in 2022). Rooftop PV is projected to have a very small impact on peak demand because the peak has already shifted to outside daylight hours. It should be noted that rooftop PV enables households to charge their home batteries (where applicable), which as discussed below, which reduces peak demand by around two per cent by 2045. The penetration of residential and commercial rooftop solar PV is projected to reach around 47 per cent and 90 per cent respectively, of eligible building roof space[30] by 2045 The projections incorporate tariff reform via the rooftop solar and home battery uptake models and assumed EV charging profiles.

There is the opportunity to effect modest increase in the rates and levels of PV uptake even though base case growth is strong. This is reflected in the proposed scenarios.

9.2.1.5 Deployment of batteries

Under the base case, by 2045, household batteries are projected to reduce peak demand by around 2 per cent, rising from 1 per cent in 2022. Projected additions to peak demand by electrification far outstrip the reduction brought about by household batteries. The penetration of household batteries is projected to reach around 25 per cent of eligible households by 2045. The projections incorporate tariff reform via the rooftop solar and home battery uptake models and assumed EV charging profiles.

[30] Of all commercial floorspace, on average around 30 per cent is assumed to have eligible roof space.

Large-scale batteries, community level batteries and V2G behave very similarly in the market – that is, they are large enough to be operated or traded by a market participant, for example, an aggregator, retailer, network operator or generator. These batteries have a role in the energy-only market and also in ancillary services market, providing grid stabilising services. Their impact on the wholesale electricity market is to support increasing amounts of renewable generation in the market by storing energy in times of excess renewable generation and generating to fill gaps in dispatchable supply.

V2H behaves like a home battery storage system. It increases a household's storage capacity, which would be expected to reduce peak demand. Wide-scale battery uptake creates a range of grid management issues, which may mean the grid operator needs to intervene to control when batteries charge/discharge if this threatens grid stability/balance. While this will not constrain the installation and deployment of batteries, it may limit their impact to contribute to the net zero emissions pathway.

Therefore, actions aimed at increasing the deployment of batteries (BESS, community batteries and large batteries) are not assessed as providing a significant opportunity in pursuit of net zero emissions outcomes, given the impact on peak demand is relatively small. Grid management considerations may constrain deployment and use. However, they can all play a significant role in delivering energy security through grid outages. Accordingly, the scenarios look to incorporate modest increases in battery uptake.

9.2.1.6 Network opportunities and constraints

The modelling in this report has considered reasonably traditional approaches to addressing capacity and supply quality constraints that are forecast to occur on the network. These approaches typically result in the augmentation of the network with either larger or additional equipment to address constraints.

As discussed in Chapter 7 there are a number of locations where there is forecast rapid growth in customer connections (such as the Molonglo/Woden area) where largely the traditional approaches of performing augmentations will be the most successful as they provide large step changes in capacity and leverage off the existing infrastructure for assisting with security and reliability.

However, there are emerging demand management technologies and processes that can be used to potentially defer augmentation which have not been considered in the analysis. Demand management has not been considered as it has traditionally not been of a large enough scale to materially shift the times of investments in the models.

Historically some network operators have also considered demand management to be too unreliable without have required backup with non-renewable portable generation if demand curtailment from customers is not achieved.

With the increased penetration of smart meters and the falling price of batteries, demand management opportunities are increasing in terms of both scale and cost. Some examples of these opportunities are outlined below.

- In Victoria where there is already high penetration of smart meters (>98 per cent of residential customers have smart meters) technologies have been implemented by the network authorities and 3rd parties that enable customers to see their energy consumption in real time. This makes it easier for them to participate in demand management programs and understand the impact on themselves personally when participating in demand management.

  - o Further use of smart meters in Victoria has also enabled distribution business to manage demand through controlling the network voltages in targeted areas when demands are high. This technology has been used in both demand management activities for localised demands and in whole scale state level demand events.
  - o In Victoria smart meters were rolled out network operators which largely led to metering infrastructure being specified and installed to provide benefits beyond efficient and timely metrology to the network operators. In the ACT smart meter rollout will be performed by retailers who will primarily be focused on efficient and timely metrology. This does not exclusively prevent Evoenergy from setting up similar tools to those implemented in Victoria as the main components responsible for these initiatives are derived directly from the metering and communications components of the smart meter.
  - o To enable this, Evoenergy would need to have agreements in place to ensure that data is provided in a timely and consistent manner at an appropriate level of detail. Where data cannot currently meet the requirements to facilitate similar tools to those in Victoria, Evoenergy may need to work with the meter owner and vendors to perform software updates. In Victoria, many software updates were performed on meters to increase the units of measure recorded, the sampling rates and frequency of data being sent in order to develop the tools currently in use.

- With the price of batteries expected to fall further in the future there will be more opportunities for 3rd parties and network operators to install batteries.
- Network operators can dedicate batteries to demand management and 3rd parties will have the opportunity to install batteries for both demand management and arbitrage.

While demand management has not been considered in this analysis, any demand management activities undertaken in the future will positively benefit the ACT in its goal to reach net zero emissions through reducing overall electricity demand. Demand management will typically work best in locations where the growth in demand is small.

The observations of this study suggest that one example where it may be possible would be to defer the installation of a 3rd transformer at Belconnen zone substation where the demand is forecast to grow at around 3MW each year at the time where augmentation is required. This could possibly be deferred a small number of years if a battery system similar to the one used at Molonglo is implemented.

10. Proposed scenarios to support net zero emissions pathway modelling

This Chapter provides an overview of the three alternative scenarios developed and proposed to inform the government's decision making as to policy and regulatory drivers to deliver the net zero emissions pathway. The scenarios reflect plausible and realistic energy futures to which the Territory could aspire.

The scenario options have been developed following consultation with key Government stakeholders (through the scenario workshop) and fine-tuned considering both the base case outcomes and regular information exchanges as to Evoenergy's internal modelling work.

The scenarios incorporate a number of parameters encompassing various adoption/transition profiles based on the modelling undertaken. They include forecasts of costs, electricity demand and emissions reductions for different periods from the present to 2045.

Under all scenarios the use of natural gas is expected to be zero by 2045 (or earlier). If the gas distribution is still in use, it will only be for supplying hydrogen or biogas, which will be produced in the ACT or purchased through offsets.

Parameters considered include:

- demand for gas from the gas network and the rate of household electrification
- uptake rates of household and commercial PV (percentage of suitable roof space on which PV panels have been installed)
- percentage of installed domestic PV systems with batteries
- capacity of large-scale battery storage installed
- capacity of neighbourhood/community battery storage installed
- level of energy efficiency (low/moderate/high) drawing on AEMO ISP scenarios; annual energy savings (GWh) in 2045; percentage change from base case
- rate of uptake of EVs - percentage of the fleet that is EVs by 2045
- percentage of EVs that are used as 'batteries' to supply homes (V2H) or the grid (V2G).

The scenarios to be modelled are agreed with EPSDD.

10.1 Scenario 1: *Technology drives change*

This scenario represents a future where there is steady and ongoing adoption of existing technologies over the period to 2045 that drives the decarbonisation of the ACT economy.

In this potential future, there remains a relatively high demand for energy delivered through the existing natural gas network. However, by 2045, the gas being delivered is hydrogen or biogas. Some of that gas may be produced in the ACT, but most will be purchased through offsets.

10.1.1 Key input assumptions

In line with current policy, there will be no new connections to the gas network for construction in greenfield and in-fill areas. Around one per cent of existing gas customers switch to electricity every year over the period to 2045. This occurs in response to a sustained, but relatively modest, government program to incentivise customers (primarily lower income households) to switch away from gas. By 2045 the demand for energy through the gas network will decrease by approximately 80 per cent compared to existing demand. Residual offset options will be identified and discussed (but work will not extend to identifying/costing approaches the Government might adopt).

In the *Technology drives change* future world there continues to be a high demand for electricity from the grid. This is driven by growth in population and the growth in the number of fully electric households and businesses and increasing electrification of public and private transport. The adoption of EVs increases slightly more rapidly than in the base case. Private EVs will make up 13 per cent of the fleet by 2030 (or approximately 42,000 EVs), 33 per cent of the fleet by 2035 (around 114,000 EVs) and 68 per cent of the fleet by 2045 (around 270,000 EVs). These figures align with the Deloitte 'optimistic' forecast.

Adoption of EVs is driven by ongoing, relatively modest, government support programs that help to reduce the purchase and operating costs of an EV. In addition, sales of new internal combustion engine (ICE) vehicles cease in 2035 as manufacturers switch to EVs.

The conversion of the bus fleet to zero emissions vehicles between 2022 and 2040 will be accelerated in compared to the base case. Public transport is 100 per cent zero emissions by the mid-2030s. Privately owned vehicles such as garbage trucks, taxis and rideshare vehicles will follow a similar path.

Roof top PV installations increase steadily over the outlook period. By 2045, around 60 per cent of (suitable) private homes in Canberra have PV installed (roughly three times the current penetration rate of domestic PV systems).

Driven by declining costs of PV systems and the need to meet emissions targets, commercial businesses will rapidly install PV and battery systems. By 2030, some 50 per cent of suitable available commercial roof space will have PV and battery systems installed on it. This increases to 75 per cent by 2035, and 95 per cent by 2045.

In this scenario, the capacity of large-scale battery storage in the ACT increases rapidly, with 660MW of storage distributed across the ACT by 2025. A further 110MW of storage is added by 2035. As the cost of home batteries declines, they are increasingly installed by consumers with PV systems. By 2030, 15 per cent of all households with PV systems have installed home batteries, that increases to 30 per cent by 2035 and 65 per cent by 2045. Some of this storage capacity may be installed in community based/suburban battery storage hubs.

EVs can be used as batteries when they are not being used as transport. EVs can provide stored electricity either directly to the grid (V2G) or to the home (V2H). The number of EVs used to store and supply electricity in this way gradually increases. By 2030, 5 per cent of the EV fleet is used in this way (or approximately 2,100 EVs), increasing to 10 per cent by 2035 (around 11,400 EVs) and 26 per cent by 2045 (some 54,000 EVs). These figures are based on the 'hydrogen superPower' scenario in the latest ISP assumptions workbook (the scenario with the highest V2G and V2H levels). The additional available storage capacity helps to maintain a stable grid as the number of PV systems increases.

The *Technology drives change* scenario sees increased consumer interest in energy efficiency. This is driven by consumers' desire to improve the comfort of their homes and reduce the amount they spend on energy. Modest government support for energy efficiency (particularly for low-income households), coupled with the drivers mentioned above, lead to moderate energy savings of around 685 GWh by 2045 (around 40 per cent more energy savings than the base case). Scenario 1 uses AEMO's ISP 'net zero by 2050' scenario and assumes NCC 6.5 stars in 2025, 7 stars in 2039, 7.5 stars in 2047.

10.2 Scenario 2: *Decentralisation is king*

The *Decentralisation is king* scenario envisages an ACT that has seen significant changes in how energy is produced and used across the Territory. There will be much greater decentralisation of energy production and storage. This, coupled with a stronger interest in improving energy efficiency, will lead to lower demand for electricity supplied from the grid. The grid will continue to be used to meet some consumers supply needs and address short term energy imbalances. This scenario includes many of the technology solutions from Scenario 1 – to the extent they are compatible with a decentralised system.

10.2.1 Key input assumptions

In the *Decentralisation is king* scenario we assume that out to 2035 around one/two per cent of existing gas customers switch to electricity each year (in effect it follows the base case projections). The rate of switching each year then increases to around three per cent out to 2045, by which time there are only around half the number of gas customers as in 2022. The reduction in the consumption of natural gas is in line with the Scenario 1. By 2045 the demand for energy through the gas network will decrease by approximately 80 per cent compared to existing demand. All the gas being delivered in 2045 is either hydrogen or biogas. Some may be produced in the ACT, and some purchased through offsets.

In this scenario, in line with current policy, there will be no new connections to the gas network for construction in greenfield and in-fill areas. The growth in the installation of PV panels and home batteries will help to drive a steady shift away from gas by households. This is further encouraged by a sustained government program to incentivise customers to switch away from gas.

The adoption of EVs in the *Decentralisation is king* scenario is like that seen in Scenario 1. Sales of new ICE vehicles cease by 2035. Private EVs are 13 per cent of the fleet by 2030, 33 per cent of the fleet by 2035 and 68 per cent of the fleet by 2045 (these align with the Deloitte 'optimistic' forecast). The conversion of public transport to zero emissions follows the same path as for Scenario 1, as do privately owned vehicles such as garbage trucks, taxis and rideshare vehicles.

Roof top PV installations increase very strongly over the outlook period. By 2045 around 90 per cent of (suitable) private homes in Canberra have PV installed (over four times the current penetration rate of domestic PV systems). The uptake of PV systems is driven by declining costs of PV systems, strong policy signals and incentives, and consumers' desire for energy independence. Those factors, and the need to meet emissions targets, will also drive commercial businesses to install PV and battery systems. By 2030 some 50 per cent of suitable available commercial roof space will have PV and battery systems installed, this increases to 75 per cent by 2035, and 90 per cent by 2045.

The desire for energy independence and declining battery costs could also see home batteries being increasingly installed by consumers with PV systems. By 2030, 20 per cent of all households with PV systems have installed home batteries, that increases to 40 per cent by 2035 and 75 per cent by 2045. Storage capacity provided through community based/suburban battery storage hubs will expand considerably, coupled with the deployment of Virtual Power Plants (VPPs).

In this scenario the ACT has the same rapid increase in large scale battery storage as in Scenario 1, with 660MW of storage distributed across the ACT by 2025. However, there are no further additions to large scale storage as behind the meter batteries installed by households provide sufficient storage to ensure reliable supply.

EVs can be used as batteries when they are not being used as transport. The EVs can provide stored electricity either directly to the grid (V2G) or to the home (V2H). The number of EVs used to provide electricity to the grid or home gradually increases over time. By 2030, 5 per cent of the EV fleet is used in this way, increasing to 10 per cent by 2035 and 26 per cent by 2045. The installed storage capacity helps to maintain a stable grid as the number of PV systems increases.

The *Decentralisation is king* scenario sees much greater consumer interest in improving energy efficiency. This is driven by consumers' desire to improve the comfort of their homes and ensure that their energy use can largely be met from the own household PV/battery systems.

Strong government support for energy efficiency and DER systems, and rapid improvements in efficiency standards, coupled with the drivers mentioned above, lead to moderate/high energy savings of around 800 GWh by 2045 (or around 65 per cent more energy savings than base case). The scenario uses AEMO's ISP 'strong electrification' scenario and assumes NCC 7 stars in 2022, 7.5 in 2027, 8 in 2030, 8.5 from 2035.

10.3 Scenario 3: *Policy drives change*

This scenario assumes there are very concerted government efforts to encourage much more rapid reduction in the use of natural gas in the ACT. This is done through ongoing, strong policy and program measures. Options from both Scenarios 1 and 2 are incorporated to the extent possible while maintaining reliable and appropriate supply.

10.3.1 Key input assumptions

In this scenario, and in line with current policy, there will be no new connections to the gas network for construction in greenfield and in-fill areas. In the *Policy drives change* scenario, a strong and sustained suite of government measures will encourage around 6-7 per cent of existing gas customers a year to switch to electricity (to facilitate phase-out of the system in 2035).

The rapid decline in the number of gas customers increases the network costs that the remaining customers must pay for gas supply, increasing the pressure on customers to electrify their homes. There is a steady reduction in household natural gas consumption. As this trend continues, it becomes uneconomic to continue to operate the gas network, and it is largely shut down by 2035. Any remaining commercial users of gas will only use tank biogas or hydrogen, or in the case where natural gas is required (say for industrial feed-stock purposes), this usage will be offset.

In this scenario, large scale battery storage grows beyond the 660MW currently planned to be installed by 2025. A further 100MW is installed by 2035 and a further 100MW by 2045. The additional storage is required as gas use essentially ceases.

Government legislation and programs support the uptake of EVs and discourage the sales of new ICE vehicles after 2025 causes the sales of EVs to increase rapidly. Sales of new ICE vehicles ceases by 2035. Private EVs make up 13 per cent of the fleet by 2030, 33 per cent of the fleet by 2035, and 68 per cent of the fleet by 2045. These figures align with the Deloitte ‘optimistic’ forecast’. The public transport fleet is fully zero emissions vehicles by 2035, as are privately owned vehicles such as garbage trucks, taxis and rideshare vehicles.

Under the *Policy drives change* scenario, the ACT Government strongly encourages the installation of solar PV. By 2035, 80 per cent of (suitable) private homes in Canberra have installed rooftop PV systems. This increases to 95 per cent by 2045. Incentives to install home batteries lead to them being rapidly adopted by consumers. Batteries are installed at 20 per cent of all households with PV by 2030, 40 per cent by 2035 and 85 per cent by 2045. Government incentives may need to be provided to commercial businesses to accelerate the installation of PV and battery systems. By 2030 some 50 per cent of suitable available commercial roof space will have PV and battery systems installed on it. This increases to 75 per cent by 2035, and 95 per cent by 2045.

Scenario 3 assumes higher autonomous/market-led energy efficiency improvements will occur. Mandated energy efficiency standards and enhanced support programs lead to significant energy efficiency gains of around 880 GWh by 2045 (or around 80 per cent more energy savings than base case). The scenario uses the AEMO ISP 'step change' and 'hydrogen superPower' scenarios, and assumes NCC 7 stars in 2022, 7.5 in 2027, 8 in 2030, 8.5 from 2035.

The number of EVs used for V2H and V2G slowly increases over time, say 10 per cent of the EV fleet in 2030, 20 per cent by 2035 and 40 per cent by 2045.

10.4 Scenario modelling approach

We will model each scenario as a standalone option, delivered through modifying the base case parameters. in Table 9, Section 10.5 details the key variables that will be adjusted, including gas demand, rooftop PV and battery deployment, EV uptake and energy efficiency gains. The underlying assumptions and rationale for changes will be detailed. We will include commentary on how the modelling accounts for differences in housing diversity (such as suburb age; housing density/stock mix etc) and potential limitations/fetters to electrification.

The scenario analysis will include commentary on residual gas demand (where the gas network continues to operate at a reduced capacity) including options for using offsets to deliver’ green gas. These may be through the purchase of green gas (as per the 100 per cent renewable electricity auctions) and alternative approaches (for example carbon farming/credits).

While green gas may be a long-term option, the work will not extend to a full transition model and will not explicitly explore the maintenance of the network where it is economically viable to do so. Options relating to alternate gas churn approaches (to maintain the viability of the gas network) and associated CAPEX/OPEX costs will not be pursued. However, commentary will be included as to green gas options including consumer impacts related to the cost of appliance/network upgrade costs to facilitate the use of green gas.

As agreed, we will explore gas network ‘tipping point’ – that is at what point continued operation of the network becomes unviable, as part of the scenario analysis.

Policy and regulatory options that could be pursued by Government to ‘deliver’ the scenario outcomes will be addressed, including the rationale for Government intervention (i.e., should the Government continue to incentivise electrification and reduction in gas use if the gas network is destined to close).

10.5 Comparison of scenario assumptions

Table 9 provides a high-level overview of how the assumptions made regarding different variables change between the various scenarios.

Table 9 Scenario assumptions comparison

Variable	Description	Base case	Technology drives change	Decentralisation is king	Policy drives change
Demand for gas from gas network	Change compared from current level of gas demand (note that any gas supplied is either biogas or hydrogen (actual or offsets))	~60% reduction	~80% reduction	~80% reduction	Gas demand reduces to zero by 2035
Rate of gas household electrification	Percentage of existing gas customers that switch to electricity each year	0.85% pa	1-2% p.a. (linear)	1-3% p.a. (rising); initially follows base case, rising from 2035	6-7% p.a. (to reduce demand to zero by 2035)
Residential rooftop PV uptake (by 2045).	Percentage of households with suitable roof space on which PV panels have been installed	47%	60%	90%	95%
Residential batteries uptake	Percentage of installed domestic PV systems with batteries	25%	65%	75%	85%
Commercial PV & battery systems	Percentage of suitable commercial roof space with installed PV systems (all commercial PV systems are assumed to include battery storage)	90%	95%	90%	95%
Batteries	Amount of large-scale battery storage (located on the network, that is, 'in-front of the consumer meter') installed by 2045	660MW	760MW	660MW	860MW
	Amount of neighbourhood/community battery storage (located on the network, that is, 'in-front of the consumer meter') installed by 2045	zero	100MW	400MW	400MW

Variable	Description	Base case	Technology drives change	Decentralisation is king	Policy drives change
Energy efficiency	Level of energy efficiency (low/moderate/high) Annual energy savings (GWh) in 2045 Percentage change from base case	Low/moderate energy savings of around 485 GWh by 2045 In line with current trajectory No change from current building standards	Moderate energy savings of around 685 GWh by 2045 (or around 40% more energy savings than base case) Based on ISP 'Net Zero by 2050' scenario	Moderate/high energy savings of around 800 GWh by 2045 (or around 65% more energy savings than base case) Based on ISP 'Strong Electrification' scenario	High energy savings of around 880 GWh by 2045 (or around 80% more energy savings than base case) Based on ISP 'Step Change and Hydrogen Superpower' scenarios
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes AVs which are assumed to all be electric)	41%	68%	68%	68%
Use of EVs for V2H and V2G	Percentage of EVs that are used as 'batteries' to supply homes (V2H) or the grid (V2G). S1, S2 and S3 all based on the 'hydrogen superPower' scenario in the latest ISP assumptions workbook.	zero	Increasing from 1% in 2030 to 26% by 2045	Increasing from 1% in 2030 to 26% by 2045	Increasing from 1% in 2030 to 26% by 2045
Demand for electricity from grid	Relative measure of the demand for electricity that is supplied by the grid	High	High	Low	Medium

Source: ACIL Allen

Appendices

Appendix A

Relevant policy considerations

Policy considerations relevant to study

Policy	Commitment	Consideration in base case/scenarios
PAGA - Phase out fossil gas, support grid stability and support vulnerable households	Implement a program of zero-interest loans of up to $15,000 for households and not-for-profit community organisations to assist with the upfront costs of investing in: rooftop solar panels; household battery storage; zero emission vehicles and efficient electric appliances. The program will include an education and communications component about energy efficiency and the shift from gas to electric.	Project in implementation - impact will depend on program duration, total funding available, and take up rates (eligibility is limited based on household incomes). Would need to make assumptions on what loans are used for. Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Progress a project with relevant asset owners and key stakeholders to reduce the emissions intensity of the existing ACT gas network as much as is possible, by injecting zero-emissions gas alternatives.	Level of 'substitution' of hydrogen or biogas will be key variables across scenarios, as will total demand for gas. Base case provides for no (unforeseen) step changes in gas composition (a maximum of 20 per cent hydrogen and/or biogas gas) in line with southern NSW market expectations.
	Enact minimum energy efficiency standards regulations for rental properties in 2021 with progressive implementation over the coming years.	Not yet in place - impact will depend on speed of implementation, reach, total number of rental properties impacted and proportion of total housing stock Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Implement a five-year, $50 million program to improve building efficiency and sustainability for social and public housing, low-income owner-occupiers, and the lowest performing rental properties; this includes upgrades to government housing, and financial incentives to implement minimum energy efficiency standards in rental properties.	Not yet in place - impact will depend on number of properties affected and roll-out rate. Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Deliver at least 250MW of new 'large-scale' battery storage distributed across the ACT.	Commitment is for 250MW of new 'large-scale' battery storage distributed across the ACT in place by 2025. This takes total ACT 'large-scale' battery capacity commitments to 660MW by 2025 (includes exiting commitments factored into market - 250MW 'Big Canberra Battery' plus other ACT battery commitments by GPG and Neoen - and additional PAGA commitment) That is 110MW from 2023, 430MW from 2024 and 120MW in 2025 Base case incorporates an additional 110MW from 2023 (110MW auction batteries), 430MW from 2024 (300MW Neoen + 130MW BCB) and 120MW in 2025 (120MW BCB)
	Develop the Molonglo Commercial Centre as an all-electric commercial centre (no new connections to gas mains network, but allow transition gas arrangements such as tanks), in partnership with expert stakeholders, and use lessons from this project to assist the phase out of fossil-fuel gas in the ACT, and demonstrate national best practice.	Will lead to an increase in electricity demand (45,000 and 60,000 square metres of floor space to cater for a variety of commercial, retail, community and entertainment uses). Incorporated in the base case.

	Legislate to prevent new gas mains network connections to future stages of greenfield residential development in the ACT in 2021-22. Future stages of Jacka and Whitlam will be all-electric.	Will reduce growth in gas demand. Incorporated in the base case.
	Commence a transition project, working with industry and other stakeholders, to advance all-electric infill developments, with a goal of no new gas mains network connections to future infill developments from 2023.	Will reduce growth in gas demand. Incorporated in the base case.
	Ensure all new ACT Government buildings and facilities are fossil-fuel-gas free, including new leases. All retrofitting in Government buildings and facilities will have a goal of net zero emissions post retrofit.	Will reduce growth in gas demand, but impact difficult to access in absence of forward building/retrofitting plans and future lease plans. Not incorporated explicitly in the base case. However, the base case assumes a five per cent increase to allow for a modest acceleration (over that delivered by existing incentives/policy and BAU trends) in energy efficiency savings and deployment of rooftop solar and efficient electric appliances.
AGA - Expand the number of ZEVs in the ACT	Engage with the ZEV industry and adopt an ambitious target for new ACT vehicle sales to be zero emission by 2030.	No clear target(s) at this stage. Will increase demand for electricity and reduce demand for petrol and diesel. base case assumes EV uptake in line with 'conservative' EPSDD projections (as per provided Deloitte analysis) - assume 28 per cent new ZEV sales proportion in 2030; ramp up in line with Deloitte projections (will apply an S curve. Logistic function - slow ramp up, followed by acceleration and then maturation). Scenarios will look to accelerate uptake.
	Develop additional financial incentives to support greater ZEV uptake by businesses and the community sector.	Not yet in place - impact will depend on program duration, total funding available, and take up rates. Not incorporated in the base case.
	Implement a pathway for the ACT to use only zero emissions public transport, garbage trucks, taxi and rideshare vehicles by the mid-2030s - with no further purchase of non-zero emissions buses. Short-term leasing of buses to meet peak operational requirements is permitted. **Transport Canberra's first tranche of 90 battery electric buses**: delivering the ACT Government's vision of a zero-emission public transport fleet by 2040 industry project brief https://www.transport.act.gov.au/__data/assets/pdf_file/0011/1719065/PROSPECTUS-ZERO-EMISSION-TRANSITION-PLAN-FOR-TRANSPORT-CANBERRA.pdf	Given garbage trucks, taxis and ride share vehicles are privately owned, how will this measure be implemented? base case incorporates 90 new electric buses to be introduced by 2024 followed by phased implementation (linear projection) of the remaining bus fleet from 2025, reaching 100 per cent in 2040. The bus fleet currently consists of 450 buses with anticipated growth of 100 additional buses by 2030.
	Build at least 50 electric vehicle recharging stations across Canberra and the region, holding a reverse auction for their construction in 2021-22. This will include working with service station providers to explore broader public charging infrastructure.	Will impact electricity demand in the areas where they are built with size of impact dependant on assumptions concerning uptake of EVs and use. Incorporated in the base case.
	Enact regulation in conjunction with the Territory Plan Review to require charging infrastructure for new multi-unit residential and commercial buildings, and investigate measures to support	Regulation not yet in place so cannot assess impact given scope/reach to be determined. Will impact on electricity demand in the areas where they are built with size of that impact dependant on assumptions re uptake

	retrofitting of charging infrastructure in existing buildings.	of EVs. Nature and scale of measures to retrofit existing building unclear. Not incorporated in the base case.
	Conduct market sounding to attract zero emission vehicle industries and other economic and training opportunities to the ACT.	Not anticipated to impact electricity demand. Not incorporated in the base case.
	Research and pilot further Vehicle2Grid and Vehicle2Home projects to improve energy efficiency and grid reliability.	Not anticipated to materially impact electricity demand. Impact explored in scenarios. Not incorporated in the base case.
PAGA - Reform the ACT's building and planning systems to ensure a transition to best practice climate-ready and environmentally sustainable buildings and planning	Adopting an ACT Appendix to the Building Code of Australia in conjunction with the Territory Plan Review, which will set out improved sustainability standards that all new buildings must meet (addressing issues such as insulation, glazing, passive design, phasing out gas, and the requirement for electric vehicle charge points).	Not yet in place - impact will depend on final standards adopted Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Driving sustainable building innovation by piloting land release to include at least one 'showcase' sustainable development each year, such as a 150% living infrastructure plot ratio or a 'Scope 3' zero-emissions development that produces no net greenhouse emissions during construction and operation, and reduced car parking.	Pilot program not yet launched – impact difficult to assess in absence implementation. Not incorporated in the base case.
	Increase new dwelling site supply to meet increased demand across the housing spectrum.	Unclear how this directly impacts electricity demand. Base case incorporates demographic projections based on ACT Treasury figures which in turn will reflect demand for new dwelling sites.
	Require at least 70% of new housing development to be within Canberra's existing urban footprint, with an ambition to increase this share, in the context of an overall increase to the number of dwelling sites released over the coming decade.	Urban consolidation should result in more effective energy use. Base case incorporates demographic projections based on ACT Treasury figures.
PAGA - improve social housing and housing affordability over the next four years	Working with the landowners and community organisations to deliver the MyHome proposal in Curtin.	Pilot program not yet launched – impact difficult to assess in absence implementation. Not incorporated in the base case.
	Expanding specialist homelessness service capacity ($18 million over four years).	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
	Constructing a build-to rent affordable rental co-located with Common Ground Gungahlin and complete Common Ground Dickson.	Unclear how this materially impacts electricity demand. Not incorporated in the base case.
	Deliver a total of 400 additional public housing dwellings by 2025, inclusive of the 260 additional dwellings already committed by the Government for the period 2019-2025.	In the absence of specific standards or energy efficiency outcomes to be delivered by the additional public housing stock it is unclear how this materially impacts electricity demand. Not incorporated in the base case.
	The parties share a commitment to working towards an ambitious affordable rental housing target for dwellings focused on affordability for the second income quintile, and acknowledge there are significant challenges in land availability, industry and sector capacity to deliver additional housing, and capital demand on the Territory Budget. The Government will strive to deliver additional affordable housing	In the absence of specific standards or energy efficiency outcomes to be delivered by the additional public housing stock it is unclear how this materially impacts electricity demand. Not incorporated in the base case.

	dwellings despite these constraints, with a goal of 600 additional dwellings by 2025-26.	
PAGA - Improve Canberra's planning system	Complete the current planning review, in consultation with Canberrans, to deliver a planning system that is clear, easy to use and provides improved spatial and built outcomes across the Territory.	Until the review is completed, decisions taken, and initiatives implemented there are no specific actions to incorporate in the base case. Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Outcomes that will be delivered through the Planning Review process include: i. Substantially lifting the quality and sustainability of the design and construction of new developments ii. Improving community consultation and involvement in the development of Canberra iii. Helping households and business become climate-change ready iv. Delivering a "community compact" process to find ways to encourage affordable housing while protecting our trees, green space and heritage. The compact will bring together a wide range of different groups in the community, including residents' groups, younger people, government and developers v. Ensuring the planning and housing system continues to deliver affordable housing.	
	Implementing the previously agreed recommendations of the Standing Committee on Planning and Urban Renewal's inquiry on development applications.	
	Commencing a 10-year pathway to shift to world's best practice on climate-ready and environmentally-sustainable buildings, including expanding the ACT Appendix to the Building Code of Australia.	
	Seek advice on the best way to facilitate the outcomes contained in the Government's Waste Strategy to locate waste processing facilities in Hume.	
PAGA - Building Light Rail Stage 2	Proceed to procure the design and construction of Light Rail Stage 2 as soon as possible following assessment of infrastructure procurement options.	Timing and final decisions on design and route still subject to consideration. Will clearly impact both energy systems infrastructure and electricity demand. Opportunity to reduce future infrastructure costs if gas transition considered in planning and associated works. Base case incorporates provisions for Stage 2 – estimated that Stage 2 light rail adds 30 kW of average daily demand from 2025.
	Assess the viability and benefits of extending light rail to Mawson as part of the Stage 2B business case.	No decisions at this time. Not incorporated in the base case.
PAGA - Reducing harm from gaming while supporting sustainable clubs	Establish a Community Clubs Ministerial Advisory Council with government, industry and unions to build a long-term, sustainable clubs sector in the ACT.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
	Facilitate planning and other processes to allow clubs to diversify to other revenue generating streams, particularly development of available land for social housing and land supply purposes, that are supported by the community.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
	Provide a just transition for workers in the community clubs and gambling industry by ensuring that new or transferred employment is on permanent and secure terms; providing support and retraining for employment in new jobs of their choosing; and ensuring worker	Unclear how this directly impacts electricity demand. Not incorporated in the base case.

	entitlements are secure in business transfer or winding up. The parties agree to vigorously enforce existing regulatory requirements and support existing workers in the industry with uninhibited access to their union, training, and work health and safety enforcement.	
	Establish a five-year $5 million Building Energy Efficiency Upgrade Fund, to be accessed by community clubs.	Not yet in place - impact will depend on program duration, total funding available, and take up rates (eligibility). Would need to make assumptions as to how funding might be applied to determine if this will materially impact electricity demand. Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Support clubs to become heat and smoke refuges for local communities. This will include ensuring appropriate air filtration systems, and financial payments for venues designated as official extreme weather refuge sites.	Unclear how this directly impacts electricity demand. Not incorporated into the base case.
PAGA - Fostering Neighbourhood Democracy	Commence a pilot of Neighbourhood Democracy projects in five suburbs across all regions of Canberra, using participatory budgeting to determine local expenditure, improving local community connections and resilience, and will include a published evaluation of the program.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
Climate Change Strategy 2019-2025 - Community Leadership	Encourage community driven solutions to climate change.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
Climate Change Strategy 2019-2025 - Just transition	Support Low-income residents - Partner with community service organisations to identify vulnerable and disengaged sectors of the community and implement measures to support their participation in shifting to net zero emissions.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
Climate Change Strategy 2019-2025 - A just transition for workers	A just transition for workers - Engage with industry and workers to identify sectors likely to be affected by the transition to a net zero emissions economy and support re-training of workers where needed.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
Climate Change Strategy 2019-2025 - Transport	Plan for a compact and efficient city 3.3 Plan for a compact and efficient city with improved access to sustainable transport options by delivering up to 70% of new housing within our existing town and group centres and along key transit corridors.	Planning strategies will directly impact electricity demand. Base case incorporates demographic projections based on ACT Treasury figures which in turn reflect demand for new dwelling sites and moves to a compact and efficient city.
	Increase use of public transport 3.4 Prioritise improving public transport services and supporting infrastructure, including buses, light rail stage two and connecting services. 3.5 Maximise accessibility to the rapid bus and light rail networks through feeder services and expanding the Park and Ride network.	In the absence of explicit targets and timing it is difficult to assess the extent to which public transport demands grow and the subsequent impact on electricity demand. Furthermore COVID-19 considerations are like to dampen demand in the short term. Not incorporated in the base case.
	Encourage Zero Emissions vehicles 3.20 Explore and trial financial incentives such as increased registration discounts, rebates and low interest loans to encourage the uptake of zero emissions vehicles and electric bikes. 3.21 Implement the Zero Emissions Vehicles Action Plan 2018–21, explore opportunities to promote investment in public charging infrastructure, and identify new actions to	Incentives and regulatory drivers not yet in place - impact will depend on program duration, total funding available, take up rates (eligibility) and the details of any new regulations. Will increase demand for electricity and reduce demand for petrol and diesel. Base case assumes EV uptake in line with 'conservative' EPSDD projections (as per

	support the uptake of zero emissions vehicles from 2021 onwards. 3.22 Amend road rules to facilitate the safe use of new sustainable personal mobility options, such as electric scooters. 3.23 Investigate regulatory options to drive the transition to zero emissions commercial vehicle fleets.	provided Deloitte analysis) - assume 28 per cent new ZEV sales proportion in 2030; ramp up in line with Deloitte projections (will apply an S curve. Logistic function - slow ramp up, followed by acceleration and then maturation). Scenarios will look to accelerate uptake. Base case incorporates impact of new recharging facilities and conversion to an electric bus fleet.
Climate Change Strategy 2019-2025 - Energy, Buildings & Urban Development - Maintain 100% renewable electricity supply	4.1 Legislate a 100% renewable electricity target to continue from 2020.	Ensures ACT can continue to ensure an emissions free electricity system. Incorporated in the base case.
	4.2 Develop and implement a Sustainable Energy Policy 2020–25 that sets out actions to deliver sustainable, affordable and reliable energy to the Territory and drives the continued development of the renewable energy industry in the ACT.	Until the policy is finalised, decisions taken, and initiatives implemented there are no specific actions to incorporate in the base case. Not incorporated in the base case.
Climate Change Strategy 2019-2025 - Energy, Buildings & Urban Development - Reduce emissions from gas	Amend planning regulations to remove the mandating of reticulated gas in new suburbs.	Will drive fully electrification of new developments and increase demand for electricity. Incorporated in the base case.
	Conduct a campaign to support the transition from gas by highlighting electric options and savings opportunities to the ACT community.	Will help build community support for electrification. Campaign not yet delivered, and in and of itself is not likely to materially affect electricity demand. Any gains likely to be realised as part of incentives to drive electrification. Not incorporated explicitly in the base case. However, the base case assumes a five per cent increase to allow for a modest acceleration (over that delivered by existing incentives/policy and BAU trends) in energy efficiency savings and deployment of rooftop solar and efficient electric appliances.
	Develop a plan for achieving zero emissions from gas use by 2045, including setting timelines with appropriate transition periods for phasing out new and existing gas connections.	Aligns with PAGA policies concerning no new gas connections. Electrification of existing properties will increase demand for electricity. Timelines to be explored as part of scenario modelling (including ‘green gas’ options). Changes in gas usage incorporated in the base case.
Climate Change Strategy 2019-2025 - Energy, Buildings & Urban	Introduce mandatory disclosure of energy performance for all rental properties.	Yet to be enacted but will lead to more informed choices focused on energy efficiency. Whether or not this will manifest itself in terms of impacting energy demand is yet to be tested. Not incorporated explicitly in the base case. However, the base case is derived from AEMO’s ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	By 2021 introduce legislation for staged minimum energy performance requirements for rental properties to come into force in 2022–23.	Legislation still in development so impact on overall electricity demand cannot be determined. Unlikely to materially impact demand at the whole of ACT level. Not incorporated explicitly in the base case. However, the base case is derived from AEMO’s ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
	Expand the Actsmart Home Energy Program to provide free, tailored in-home energy assessments for renters.	Yet to be rolled out but is expected to lead to more informed choices focused on energy efficiency – impact in terms of impacting

		energy demand is yet to be tested but may not be material. Not incorporated explicitly in the base case. However, the base case is derived from AEMO's ISP base case scenario which takes into account existing policies and programs to drive energy efficiency savings.
Climate Change Strategy 2019-2025 - Energy, Buildings & Urban Development - Climate-wise, zero emissions Public housing	Continue to upgrade to efficient electric appliances in existing public housing properties where technically feasible and assess the costs and benefits of shifting to all-electric public housing.	Will decrease demand for gas from public housing stock and increase electricity demand. A step change in application is not envisaged given it is a 'continuance' of current efforts. Base case assumes existing public housing stock transitions to electric appliances over the next 10 years.
	Ensure all newly constructed public housing properties are all-electric (fitted with efficient electric appliances) from 2019.	Will increase electricity demand over BAU. Incorporated in the base case.
ACT Planning strategy - Compact & Efficient city	Investigate the potential for new residential areas to the west of the city to meet future housing need.	Planning strategies will directly impact electricity demand. Base case incorporates demographic projections based on ACT Treasury figures which in turn reflect demand for new dwelling sites and moves to a compact and efficient city.
	Use infrastructure efficiently to support our growing community.	
	Continue to work with the NSW Government and Councils to implement joint initiatives to understand and manage growth in the Canberra Region.	
ACT Planning strategy - Diverse Canberra	Recognise and protect existing industrial areas and service trade areas as important elements of a diverse economy.	Maintaining gas supply for industrial users (where 'green gas' is not a viable alternative feedstock may be critical to so elements of the community. A specific needs assessment will be required to determine demand – which may well have implications for ongoing gas supply. Not incorporated in the base case.
	Plan for adequate employment land in the right location that supports a diverse range of uses including commercial and industrial land linked to supportive infrastructure, transport options and investment opportunities.	Planning strategies will directly impact electricity demand. Base case incorporates demographic projections based on ACT Treasury figures which in turn reflect demand for new dwelling sites and moves to a compact and efficient city.
	Transitioning to net zero emissions city through the uptake of renewable energy, improved building design and transport initiatives.	Until specific decisions or planning approaches are implemented there are no specific actions to incorporate in the base case. The base case assumes the continued purchase of 100 per cent renewable electricity and addresses electrification od the gas system. While other factors are not incorporated explicitly in the base case, it does include a number of initiatives in relation to infrastructure and public housing which relate to the planning strategy. Furthermore, the base case assumes a five per cent increase to allow for a modest acceleration (over that delivered by existing incentives/policy and BAU trends) in energy efficiency savings and deployment of rooftop solar and efficient electric appliances.
ACT Planning strategy - Liveable Canberra	Deliver social infrastructure that meets community needs and supports strong communities.	
	Deliver housing that is diverse and affordable to support a liveable city.	
ACT Planning strategy - Accessible Canberra	Enhance accessibility by better integrating transport and land use.	Until specific decisions or planning approaches are implemented there are no specific actions to incorporate in the base case. Not incorporated explicitly in the base case. However, the base case incorporates a

		number of transport initiatives which relate to the planning strategy.
City to Woden Light rail		Timing and final decisions on design and route still subject to consideration. Will clearly impact both energy systems infrastructure and electricity demand. Opportunity to reduce future infrastructure costs if gas transition considered in planning and associated works. Base case incorporates provisions for Stage 2– estimated that Stage 2 light rail adds 30 kW of average daily demand from 2025.
Health Planning Future - Planning for the Future	Hospital & health service expansions - full electrification of the Canberra hospital	Will increase electricity demand – may have localised network infrastructure implications. Opportunity to reduce future infrastructure costs if gas transition considered in planning and associated works. Implications and costs associated with change from gas to electricity in relation to the hydrotherapy pool/certain health services may be expensive/challenging. Base case assumes full electrification of the Canberra hospital.
CIT Campus Woden	Government to build new educational and community facilities at Woden Town Centre (https://www.act.gov.au/citcampuswoden/overview/project-overview)	New facility to be 22,500m^2 is scheduled to open in 2025. Base case assumes full electrification of the CIT facility.

Source: GHD/ACIL Allen based on policy stocktake by the Environment Planning and Sustainable Development Directorate, ACT Government

Appendix B

Simulation models

GasMark Model

At its core, *GasMark* is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model). The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price. The model incorporates assumptions about:

- gas supply (reserves, production rates, minimum selling prices)
- gas demand at individual customer or customer group level (annual quantity, price tolerance)
- existing and possible future transmission pipelines (current capacity, future expansions, tariffs) and
- LNG terminals.

Gas storage facilities are represented in the model and include assumptions with regard to total storage capacity, maximum injection and withdrawal rates, cushion gas requirements, storage losses, and price limits for purchase of gas into storage and sale of gas from storage.

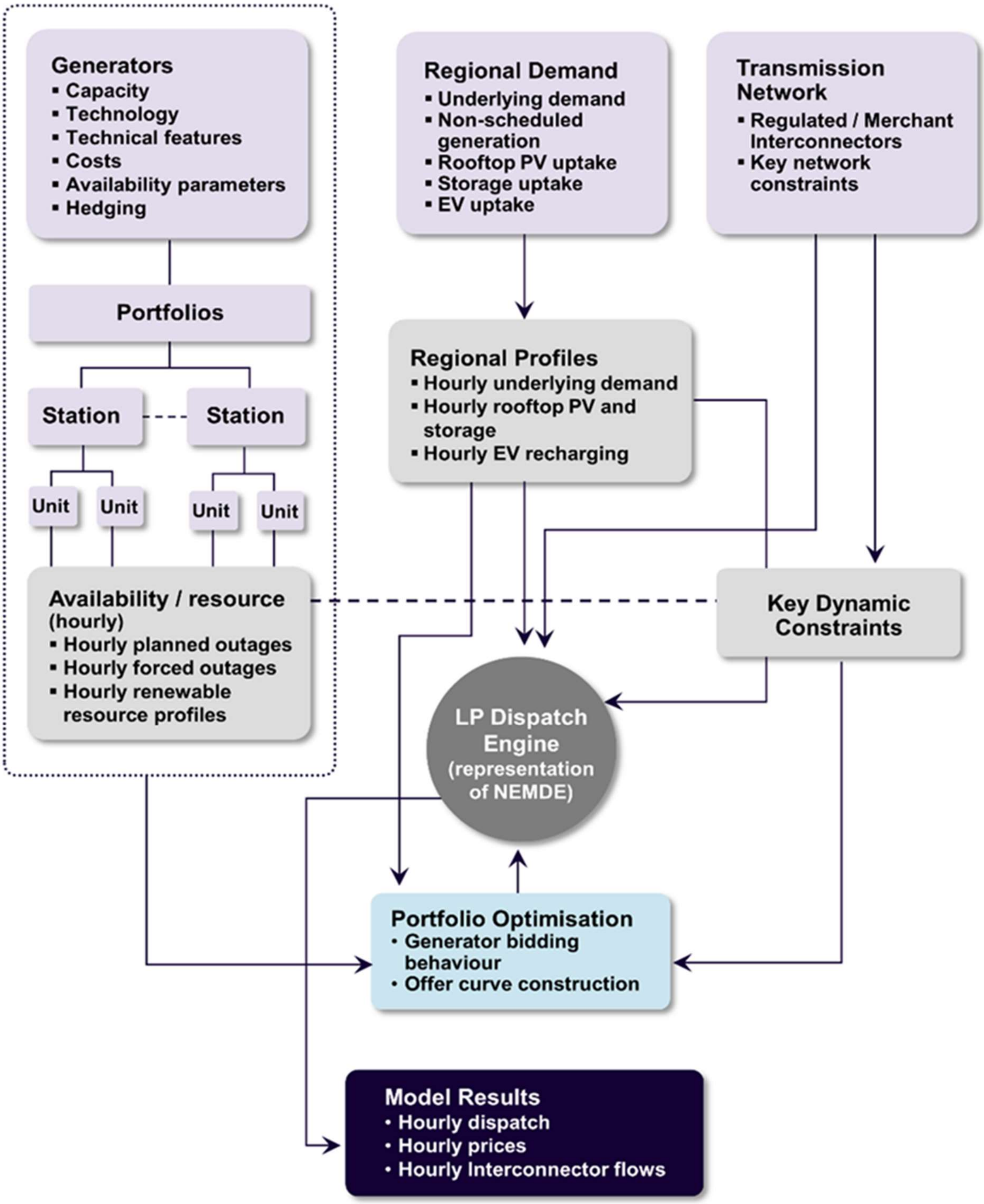
PowerMark

PowerMark has been developed over the past 20 years in parallel with the development of the NEM, the National Electricity Market of Singapore (NEMS) and the Philippine Wholesale Electricity Spot Market (WESM). ACIL Allen uses the model extensively in simulations and sensitivity analyses conducted on behalf of industry clients. At its core, PowerMark emulates the settlements mechanism of the NEM. *PowerMark* uses a linear program to settle the market, as does the market operator's NEM Dispatch Engine (NEMDE) in its real time dispatch process. Like the NEMDE, *PowerMark* simulates the operational demand segment of the market which is satisfied by scheduled and semi-scheduled generation.

PowerMark also emulates the manner in which generators offer supply into the NEM in an attempt to profit maximise by iterating the generator offer curves. *PowerMark* constructs an authentic set of initial offer curves for each generator unit prior to matching demand and determining dispatch through the market clearing rules. Unlike many other models, *PowerMark* encompasses re-bids to allow each major thermal generation portfolio in turn to seek to improve its position — normally to maximise (uncontracted) revenue, given the specified demand and supply conditions for the hourly period in question.

In other words, unlike some other models, *PowerMark* is not a pure SRMC/LRMC model. *PowerMark* simulates the NEM at the hourly resolution level – it runs 8,760 simulations per year of the projection period. It is important to run the model at this level of resolution.

The NEM is an energy only market in which price volatility plays a critical role in providing signals to market participants. Price volatility within a given hour arises due to the coincidence of factors such as high demand, multiple power station outages and/or lower renewable energy resource availability. Modelling 8,760 hours per year allows the projection to capture an appropriately representative set of the different combinations and permutations of the state of the NEM.


Generators
▪ Capacity
▪ Technology
▪ Technical features
▪ Costs
▪ Availability parameters
▪ Hedging
Portfolios
Station
Station
Unit
Unit
Unit
Unit
Availability / resource (hourly)
▪ Hourly planned outages
▪ Hourly forced outages
▪ Hourly renewable resource profiles
Regional Demand
▪ Underlying demand
▪ Non-scheduled generation
▪ Rooftop PV uptake
▪ Storage uptake
▪ EV uptake
Transmission Network
▪ Regulated / Merchant Interconnectors
▪ Key network constraints
Regional Profiles
▪ Hourly underlying demand
▪ Hourly rooftop PV and storage
▪ Hourly EV recharging
Key Dynamic Constraints
LP Dispatch Engine (representation of NEMDE)
Portfolio Optimisation
• Generator bidding behaviour
• Offer curve construction
Model Results
• Hourly dispatch
• Hourly prices
• Hourly Interconnector flows

Appendix C

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Appendix D

Base case consultation

Stakeholder consultation

Consultation with stakeholders was undertaken throughout this project to inform the development of the base case and scenario options. A variety of stakeholders were engaged from government organisations to corporations currently operating in the ACT energy market, with the engagements mainly addressing the following.

- views on the outlook for greenhouse gas emissions in the context of current and future Government policies
- potential policy options to deliver changes in the Territory's emission profile and their suitability for deployment
- potential barriers (technical, commercial, regulatory) to deployment of policy options and views on the role for Government in addressing these
- approaches used in other jurisdictions which could be applied
- views on the ability of the ACT economy to transition to different emission trajectories over various timeframes.

The tables below summarise the internal and external stakeholders who were consulted and their respective organisations.

Name	Organisation
Cath Collins	EPSDD
Daniel Harding	EPSDD
Simon Grice	EPSDD
Kim Salisbury	Chief Minister, Treasury and Economic Development Directorate (CMTEDD)
Kathy Goth	CMTEDD
Jo Dawson	Transport Canberra
Angela Armati	Community Services, Housing
Sam Engele	CMTEDD, Office of the Coordinator General for Climate Action
Amariot Rathmore	CMTEDD, Utilities Technical Regulation

Carolyn O'Neill	EPSDD
Ben Ponton, Director General	EPSDD
Geoffrey Rutledge, Deputy Director General	EPSDD
Erin Brady, Deputy Director General	EPSDD
Glenn Dougall	Transport Canberra
Adrian Piani	Major Projects Canberra

Name	Organisation
Adam Ryan	GHD
Bruce Clarke	GHD
Christian Schaefer	GHD
Clair Cass	GHD
Lara de Masson	GHD
Martin Axelby	GHD
Bob Pegler	ACIL Allen
Alex Gash	ACIL Allen
Cara Chambers	ACIL Allen
Guy Jakeman	ACIL Allen
Jim Diamantopoulos	ACIL Allen
John Söderbaum	ACIL Allen
Nanumi Starke	ACIL Allen

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