Economic and Technical Modelling of the ACT Electricity Network

Strategic Report

EPSDD

26 April 2022

→ **The Power of Commitment**

GHD Pty Ltd 008 488 373
Level 7, 16 Marcus Clarke Street
Canberra, ACT 2601, Australia
T 02 6113 3200 | **E** Advisory@ghd.com | www.**ghd.com**

Printed date	26/04/2022 3:39:00 PM
Last saved date	26 April 2022 3:31 PM
File name	https://ghdnet.sharepoint.com/sites/12550182/Shared Documents/20220131_Strategic Report _DRAFT Version3_Client Issue.docx
Author	GHD and ACIL Allen
Project manager	Lara de Masson
Client name	EPSDD
Project name	Economic and Technical Modelling of the ACT Electricity Network
Document title	Economic and Technical Modelling of the ACT Electricity Network | 01 Strategic Report
Revision version	Rev 0
Project number	12550182

Document status

Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
Draft	01	GHD ACIL Allen	B Pegler M Axelby	B Pegler M Axelby	L de Masson	L de Masson	31/1/2022
Draft	02	GHD ACIL Allen	B Pegler M Axelby	B Pegler M Axelby	L de Masson	L de Masson	08/02/2022
Draft	03	GHD ACIL Allen	B Pegler W Ling A Ryan	B Pegler W Ling A Ryan	L de Masson	L de Masson	03/03/2022
Final	04	GHD ACIL Allen	B Pegler W Ling A Ryan	B Pegler W Ling A Ryan	L de Masson	L de Masson	17/03/2022
Final	05	GHD ACIL Allen	B Pegler	B Pegler	L de Masson	L de Masson	24/03/2022
Final	06	GHD ACIL Allen	B Pegler	B Pegler	L de Masson	L de Masson	26/04/2022

Executive Summary

Climate change is a global issue and the ACT Government is committed to taking a continued national and international role in leading climate action. With the Government's overarching goal of achieving net zero emissions by 2045, transforming ACTs economy over the next few decades to reach net zero will be a complex journey of opportunity and change.

Although the Territory's greenhouse gas (GHG) emissions have fallen, reflective of the Government's commitment to action under the ACT's Climate Strategy, deeper and more targeted sectoral cuts will be required if net zero is to be achieved by 2045.

A net zero global economy is technically and economically possible by 2045 but getting to net zero will require significant transformational change. This means developing and rolling out new, innovative, and climate resilient technologies; embracing new ways of doing things and enhancing and introducing new policies and programs to support community and industry action. This includes ensuring a just transition to net zero emissions that supports the most vulnerable in our community.

Action will need to be premised on a whole-economy perspective, considering the key interactions between sectors, technologies and the energy system.

Although decarbonisation will be required in every sector across the economy, deep reductions in emissions from the energy sector could offset the need for relatively more expensive decarbonisation efforts elsewhere.

Transformation of the energy network offers significant opportunities to exploit low emission technology and enable new investments in innovation and ongoing investment in renewable energy sources. This will be of importance if the ACT is to meet forward focussed GHG emission targets whilst maintaining a resilient, reliable and affordable energy system.

To establish a clear and transparent assessment of the most viable course of action and the associated likely costs of decarbonising the energy network, the ACT Government commissioned strategic scenario (modelling) advice of current electricity network capabilities and constraints, and how future changes to natural gas, market penetration of zero emissions vehicles (ZEVs) and electricity consumption and generation are likely to impact the demand, supply and emission generation.

GHD and ACIL Allen have delivered two (2) reports as part of this commission. Stage 1 **Base case Report** modelling was completed in December 2021 and this Stage 2 **Strategic Report** presents the economic and technical modelling results across three (3) realistic policy scenarios.

The scenario modelling results set out within this report provide potential decarbonisation pathways that demonstrate the rate and scale of action that must be achieved across the energy network to support the ACT's commitment to a net zero emission future by 2045.

The Stage 2 **Strategic Report** provides strategic advice on the practicality of the ACT Government achieving its policy objectives through (3) alternative scenario pathways, whilst maintaining 100 per cent renewable electricity and balancing network capabilities, energy security, quality of supply and costs to consumers.

The key findings

Base case

The underpinning assumptions for the base case modelling are 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. Current and expected market trends were overlaid with parameters drawn from existing Government policy settings/announcements to further inform the base case modelling.

- Total gas consumption has been steadily declining over the past decade. Consumption will drop from levels around 7,000 TJ to around 3,000 TJ by 2045 based on the current policy environment (60% decline).
- Total delivered gas retail price increases in real terms from levels around 3.3 cents/MJ to levels around 4.5 cents/MJ by the mid-2040s.
- Less than half of the eligible gas appliance stock each year is replaced with electric appliances.
- Final assumed annual energy and peak demand projections result in an increase in electricity demand of 21% by 2045.
- The ACT will fall below 100% renewable from 2037, declining to around 55% of underlying demand by 2045. Suggests the Government could need to factor in further auction of renewable electricity in 2035-36. (Current policy of “banked” credits offset the need for additional purchases up until 2043.)
- The base case demand forecast will require investment of an additional $678 million in the electricity network to 2045.

Scenario 1: *Technology drives change*

The *Technology drives change* 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.

- Total gas consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045 (80% decline).
- Total delivered gas retail price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s.
- The ACT total grid energy requirement is projected to grow from 2,772 GWh in 2022 to 3,481 GWh in 2045. This is an increase of around 26%, compared to 21% in the base case.
- Total increase in the Regulated Asset Base (RAB) over the period 2020-2045 is approximately $896 million as opposed to the increase in the regulated asset base (RAB) over the same time in the base case of $678 million.

- The ACT will fall below the 100% renewable mark from 2037, declining to around 57% by 2045. The Government may need to factor in a further auction of renewable electricity around 2035, but 'banked' credits that are carried forward under the existing policy can offset the need for additional purchases up until 2045.
- Compared to the base case, Scenario 1 incurs an additional $4.0 billion in costs (with a net present value using a seven per cent real discount rate (NPV7) of $1.6 billion) associated with the increased electricity usage, while benefits will save ACT consumers $2.5 billion (or NPV7 of $842 million) in gas and fuel costs.
- Scenario 1 results in a reduction of GHG emissions over the period to 2045 of 2,325 kt CO_2-e compared to the base case. The implied emission abatement cost of Scenario 1 is +$637/t CO_2-e, with a NPV7 abatement cost of +$301/t CO_2-e.
- While Scenario 1 results in a net increase in the real Gross Territory Product (GTP) of the ACT over the period (+$340 million, or NPV7 +$100 million), it comes at a significant cost to both real income (-$1,125 million, or NPV7 of -$474 million) and jobs (-834 full-time equivalent (FTE) employee years).

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.

- Total gas consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045 (80% decline).
- The total delivered gas retail price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s.
- The ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,553 GWh in 2045. This is a decline of around 8%, compared to an increase of 21% in the base case.
- Modelling indicates that the total increase in the RAB over the period 2020-2045 is approximately $899 million as opposed to the increase in RAB over the same time in the base case of $678 million.
- The ACT will fall below the 100% renewable mark from 2038, declining to around 73% by 2045. The Government may need to factor in a further auction of renewable electricity around 2035, but 'banked' credits that are carried forward under the existing policy can offset the need for additional purchases beyond 2045.
- Scenario 2 delivers better renewable electricity outcomes, along with lower retail bill impacts in comparison with to Scenario 1.
- Compared to the base case, Scenario 2 incurs an additional $1.5 billion in costs (NPV7 of $497 million), while benefits will save ACT consumers $2.3 billion (or NPV7 of $842 million) in gas and fuel costs.
- Scenario 2 results in a reduction of GHG emissions over the period to 2045 of 2,077 kt CO_2-e compared to the base case. The implied emission abatement cost of Scenario 2 is -$375/t CO_2-e, with an NPV7 abatement cost of -$166/t CO_2-e.
- Scenario 2 is the modelled case which delivers the best outcomes against all three macroeconomic indicators over the project period, relative to the base case. It delivers a +$1,224 million (or NPV7 of +$451 million) increase

in the real GTP of the ACT; a -$165 million (or NPV7 of -$102 million) change in the real income of ACT residents; and -109 FTE employee years of employment (annual average change of -4 FTE jobs a year).

Scenario 3: Policy drives change

The *Policy drives change* 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.

- Total natural gas consumption would reduce from around 7,000 TJ to zero in 2035.
- Total delivered gas retail price projected over the projection period will increase in real terms from levels around 3.3 cents/MJ to levels around 9 cents/MJ by 2032, and to levels beyond 15 cents/MJ by 2033.
- The ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,406 GWh in 2045.
- Total increase in the RAB over the period 2020-2045 is approximately $1,093 million as opposed to the increase in RAB over the same time in the base case of $678 million.
- The overall impact on electricity retail bills is on a par with the best outcomes delivered by other scenarios. Even though retail prices under Scenario 3 are some of the highest (mainly due to high distribution network costs), the low average consumption reduces the overall bill impact.
- Compared to the base case, Scenario 3 incurs an additional $10.1 billion in costs (NPV7 of $4.4 billion), while benefits will save ACT consumers $4.4 billion (or NPV7 of $1.6 billion) in gas and fuel costs. The net change in direct costs is estimated to be +$5,672 million (or NPV7 of +$2,779 million). That is, the projected costs included in the analysis clearly outweigh the benefits.
- Scenario 3 results in a reduction of GHG emissions over the period to 2045 of 5,012 kt CO_2-e compared to the base case (more than double that achieved in Scenarios 1 and 2). The implied emission abatement cost of Scenario 3 is +$1,132/t CO_2-e, with an NPV7 abatement cost of +$554/t CO_2-e.
- Scenario 3 has the highest additional net costs, resulting in negative net outcomes against all three macroeconomic indicators over the projection period, with a substantial fall in the real GTP of the ACT; a major drop in the real income of ACT residents; and generating significantly less employment.

Next steps

Findings set out in within this **Strategic Report** indicate that achieving a net zero economy is both technically and economically possible for the ACT by 2045. However, the pathway to getting to net zero will require significant transformational change – across both policy, regulation and activity-based initiatives to support community and industry action.

Achieving equitable net zero transformation will require early action. Transformation will need to have a sustained focus on implementing policy and supporting investment programs to reduce GHG emissions and that support a resilient and sustainable ACT economy and community.

The results of the of the scenario modelling and analysis set out in this **Strategic Report** suggest that whilst there are many different approaches to decarbonisation that could be pursued, a decentralised pathway akin to Scenario 2 would appear to offer the best overall benefits. This is due to expected benefits of cost, the long-term economic viability of the Evoenergy gas network and the forecast reduction in GHG emissions.

To confirm decarbonisation as the preferred pathway to a net zero emissions future, the ACT Government will need to undertake further work to support the analysis completed to date. It is recommended that these activities to support pathway confirmation focus on:

- transition planning
- network impacts through conversion to mini systems
- (an additional auction of) renewable electricity
- incentivising technology through PVs, EVs and batteries and optimised deployment, uptake and placement of various DER
- more detailed RAB analysis to support detailed investment decisions.

Transition planning with be particularly critical if the 2045 net zero emissions target is to be achieved. Detailed timelines with supporting GHG emissions targets will be required tracking the net zero pathway selected by the ACT Government. Action premised on a whole-economy perspective will be essential if a balanced and integrated approach to achieving net zero is to be achieved whilst ensuring a just transition that supports the most vulnerable in the community.

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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
CBA	Cost-Benefit Analysis
CCGT	Combined-cycle gas turbines p
CGE	Computable General Equilibrium
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
COAG	Council of Australian Governments

ACRONYM	DEFINITION
COP	Coefficient of Performance - a performance rating indicating effectiveness in transferring heat versus electrical consumption
COP26	26th Conference of the Parties under the *United Nations Framework Convention on Climate Change* (Climate Change Convention, also referred to as the UNFCCC)
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
Evoenergy	Evoenergy operates and maintains the ACT electricity and gas network - it is part of the ActewAGL Distribution partnership.
FiT	Feed-in tariff
FTE	Full-time equivalent
FY	Financial Year
GDP	Gross Domestic Product
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
GRP	Gross Regional Product
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
GTP	Gross Territory Product
GTAP	Global Trade Analysis Project

ACRONYM	DEFINITION
GTEM	Global Trade and Environment Model
GW	Gigawatt
GWh	Gigawatt hours
HV	High voltage
ICE	Internal combustion engine
ICRC	Independent Competition and Regulatory Commission
IO	Input Output
IPCC	Intergovernmental Panel on Climate Change - constituted under the United Nations Framework Convention on Climate Change
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
LPG	Liquefied petroleum 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
NDCs	Nationally Determined Contributions - individual country commitments under the Paris Agreement to reduce national emissions and adapt to the impacts of climate change.

ACRONYM	DEFINITION
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	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
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)
Paris Agreement	The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change, dealing with greenhouse gas emissions mitigation, adaptation, and finance, signed in 2016
PJ	Petajoule
POE50	Probability of Exceedance - the 50POE mark is the average, or middle value, in any range of measurement and the most likely scenario to occur.
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
RIT-T	Regulatory Investment Test for Transmission

ACRONYM	DEFINITION
RRO	Retailer Reliability Obligation
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
UNFCCC	United Nations Framework Convention on Climate Change (Climate Change Convention, also referred to as the UNFCCC)
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 (presented in annual terms for this report).
USD	United States dollar
V2G	Vehicle-to-grid
V2H	Vehicle-to-home
VNI	Victoria-NSW Interconnector
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 Sport Market
Wobbe index	An indicator of the interchangeability of fuel gases such as natural gas, liquefied petroleum gas
ZEV	Zero emissions vehicle

1. Report overview – key findings

To establish a clear and transparent assessment of the most viable course of action and the associated likely costs of decarbonising the energy network and meeting the Australian Capital Territory's climate change objective of Net Zero by 2045, the ACT Government commissioned strategic scenario (modelling) advice of current electricity network capabilities and constraints, and how future changes to natural gas, market penetration of zero emissions vehicles (ZEVs) and electricity consumption and generation are likely to impact the demand, supply and emissions generation.

This Report provides strategic advice on the practicality of the ACT Government achieving its policy objectives through (3) alternative scenario pathways, whilst maintaining 100 per cent renewable electricity and balancing network capabilities, energy security, quality of supply and costs to consumers.

1.1 Scenario overview

The (3) alternative scenarios represent a different pathway to meeting decarbonisation goals, they represent a similar overall level of policy ambition, being:

- Scenario 1: *Technology drives change*
- Scenario 2: *Decentralisation is king*
- Scenario 3: *Policy drives change*.

Each scenario has been modelled as a standalone option against the base case. The underpinning assumptions for the base case modelling were built 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. Current and expected market trends were overlaid with parameters drawn from existing Government policy settings/announcements to further inform the base case modelling. The scenarios reflect plausible and realistic energy futures to which the Territory could aspire with key findings set out in the following Sections within Chapter 1.

1.2 Scenario 1: Technology drives change

1.2.1 Scenario description

The *Technology drives change* 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.

1.2.2 Key messages

- Total gas consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045. This represents a decline of approximately 80%. By 2045, only 60,000 connections still consume gas in the Scenario 1 compared with around 110,000 connections in the base case.

- Switching rates rising from around 1% in the 2020s, to 3% in the 2030s, and almost 10% by the 2040s.

- Under Scenario 1 and in line with projected gas consumption, emissions from the consumption of natural gas in the ACT are expected to fall from around 350 kilotonnes (kt) of CO_2 to around 80 kt by 2045.

- The total delivered gas retail price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s.

- Taking the assumed underlying demand together with the projected uptake of rooftop photovoltaic systems (PVs), battery energy storage systems (BESS), ZEVs and other electrification, the ACT total grid energy requirement is projected to grow from 2,772 GWh in 2022 to 3,481 GWh in 2045. This is an increase of around 26%, compared to 21% in the base case.

- Modelling indicates that the total increase in the RAB over the period 2020-2045 is approximately $896 million as opposed to the increase in the regulated asset base (RAB) over the same time in the base case of $678 million.

- Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of distributed energy resources (DER).

- The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests).

- The increase in location specific projects from 21 projects totalling $154 million up to 30 projects totalling $228 million (these figures include projects already underway) will result.

- Under Scenario 1 the ACT will fall below the 100% renewable mark from 2037, declining to around 57% by 2045. The government may need to factor in a further auction of renewable electricity around 2035, but ‘banked’ credits that are carried forward under the existing policy can offset the need for additional purchases up until 2045.

- Electricity retail prices (real terms) for residential, low voltage (LV) commercial and high voltage (HV) customers are projected to increase by 16%, 33% and 22% respectively over the period from 2022 to 2045. Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large-sale feed-in tariff (FiT) payments over the period.

- Compared to the base case, Scenario 1 incurs an additional $4.0 billion in costs (with a net present value using a seven% real discount rate (NPV7) of $1.6 billion) associated with the increased electricity usage, while benefits will save ACT consumers $2.5 billion (or NPV7 of $842 million) in gas and fuel costs. The net change in the direct costs is estimated to be +$1,482 million (or NPV7 of +$700 million). That is the benefits do not outweigh the costs included in the analysis.

- Scenario 1 results in a reduction of GHG emissions over the period to 2045 of 2,325 kt CO_2-e compared to the base case. The implied emission abatement cost of Scenario 1 is +$637/t CO_2-e, with a NPV7 abatement cost of +$301/t CO_2-e.

- While Scenario 1 results in a net increase in the real Gross Territory Product (GTP) of the ACT over the period (+$340 million, or NPV7 +$100 million), it comes at a significant cost to both real income (-$1,125 million, or NPV7 of -$474 million) and jobs (-834 full-time equivalent (FTE) employee years).

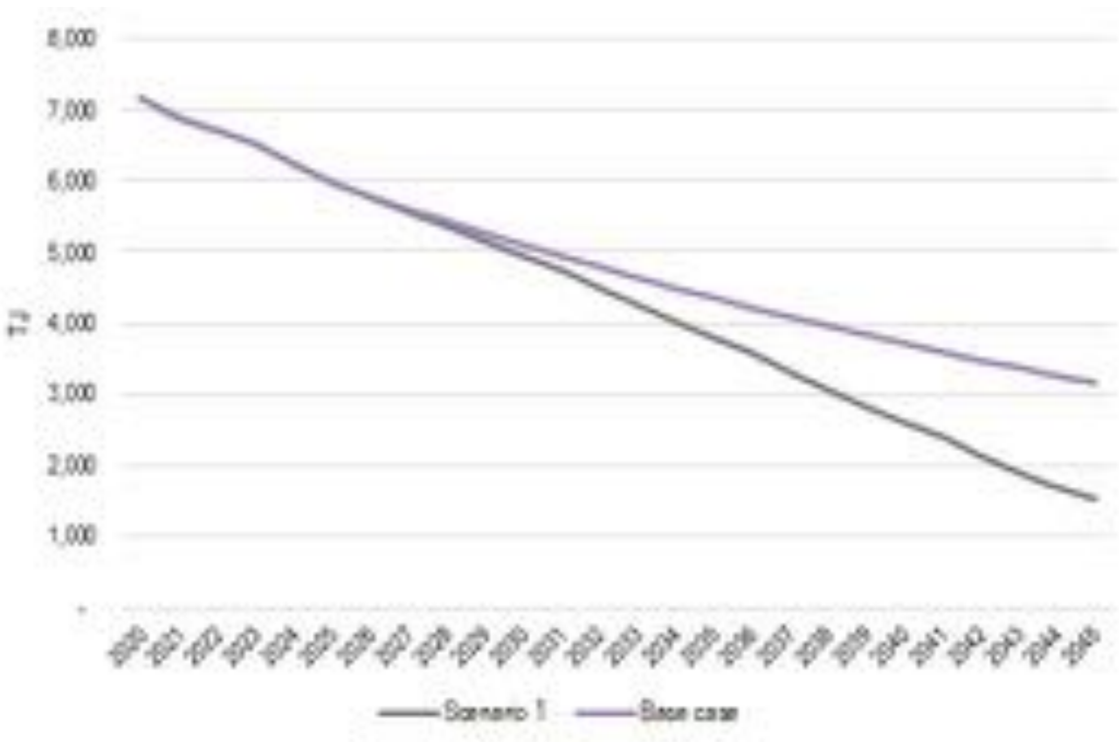
1.2.3 Key Results

1.2.3.1 Gas market projections

This scenario assumes connections will decline at a steeper rate than the base case. By 2045, less than 60,000 connections are expected to still consume gas compared with around 110,000 connections in the base case. In terms of the rate of switching, Scenario 1 experiences switching rates rising from around one per cent in the 2020s, to 3 per cent in the 2030s, and almost 10 per cent by the 2040s.

The fall in connections will result in a corresponding fall in total gas consumption with levels dropping from around 7,000 TJ currently to levels less than 2,000 TJ by 2045 as illustrated in Figure 1. This represents a decline of approximately 80 per cent against the base case.

Figure 1 Projected total gas consumption, ACT – Scenario 1 vs base case

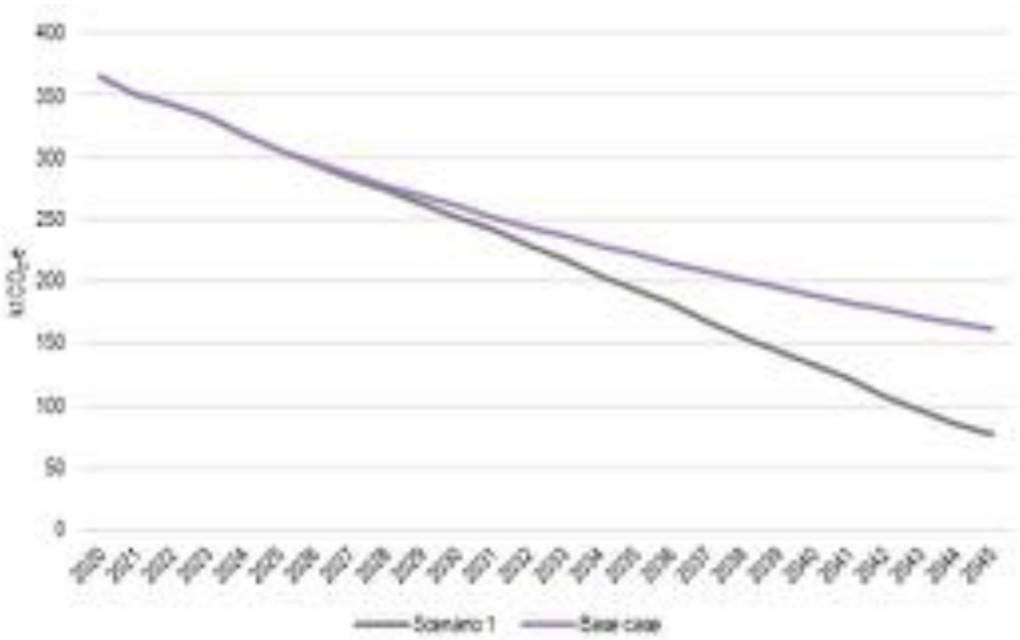


Source: ACIL Allen analysis

1.2.3.2 Implications for GHG emissions

Under Scenario 1 and 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 350 kt of CO_2 and would reduce to levels around 80 kt by 2045. Emissions are presented below in Figure 2. Scenario 1 further assumes a moderate level of energy efficiency with savings of around 685 GWh by 2045 or around 40 per cent more energy savings than the base case.

Figure 2 *Projected total gas emission reduction – Scenario 1 vs base case*

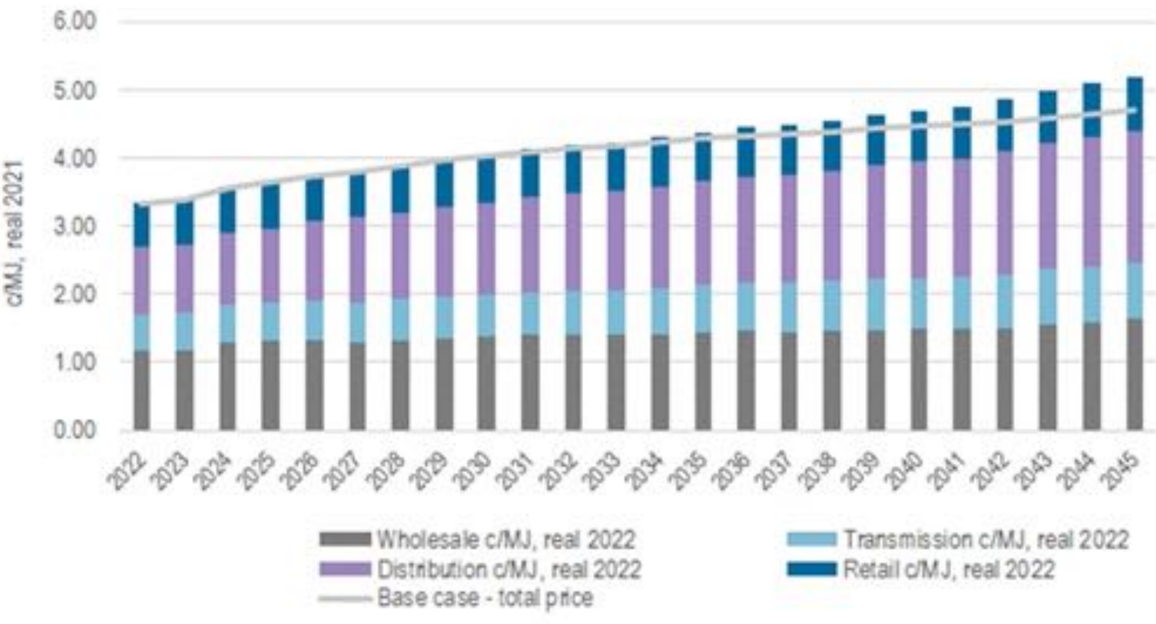


Source: ACIL Allen analysis

1.2.3.3 Gas retail price

The total delivered natural gas retail price projected over the projection period is presented below in Figure 3. The price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s. The retail price steadily increases over the entire projection period and post 2030, retail prices under Scenario 1 begin to edge higher than the base case as larger numbers of customers disconnect from gas. The projected increase in distribution tariffs is the major driver impacting price.

Figure 3 *ACT retail price for natural gas delivered to residential customers*



Source: ACIL Allen analysis

1.2.3.4 Electricity market modelling

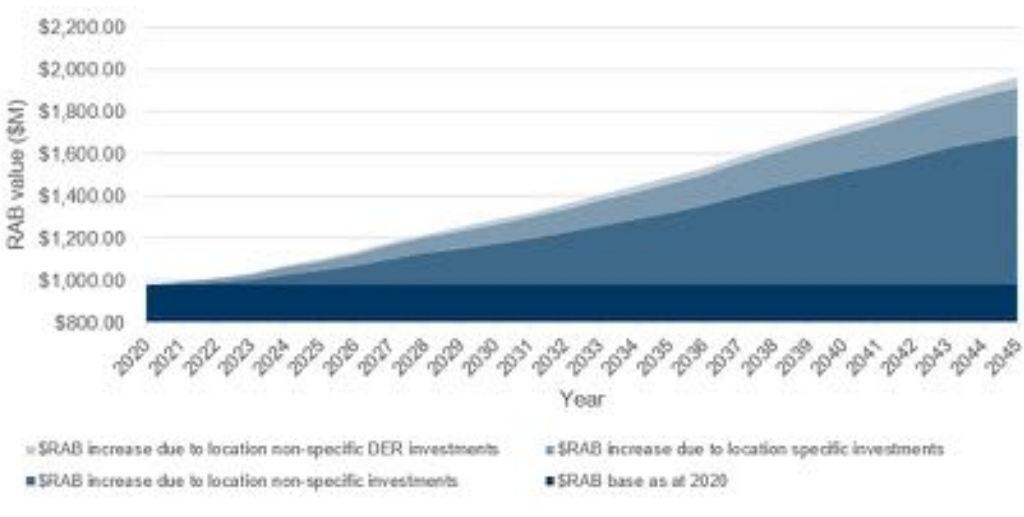
Taking the assumed underlying demand[1] together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, the ACT total grid[2] energy requirement[3] is projected to grow from 2,772 GWh in 2022 to 3,481 GWh in 2045. This is an increase of around 26 per cent over the projection period, compared to 21 per cent in the base case. ACT 50 per cent probability of exceedance (50POE) peak grid demand[4] is projected to grow from 654 MW in 2022 to 1,048 MW in 2045, which is an increase of around 60 per cent over the projection period, compared to 48 per cent in the base case. Key factors encompassed in this increase of 26 per cent include:

- delivery of 33 per cent of total energy requirements through rooftop PV by 2045
- ZEVs comprise 68 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 behind-the-meter storage on the demand profile is reasonably small given the level of uptake projected
- taking out 20 per cent more gas consumption (from 60 per cent by 2045 in the base case to 80 per cent by 2045 in Scenario 1) only increases electricity energy requirements by 166 GWh by 2045 or five per cent of total grid energy requirements by 2045
- taking out 20 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 268 MW by 2045 or 25 per cent of total peak demand by 2045.

1.2.3.5 Electricity system network analysis

The results of the modelling show that the total increase in the RAB over the period 2020-2045 is approximately $896 million as opposed to the increase in RAB over the same time in the base case of $678 million. Figure 4 shows the change in the RAB by type of investment in the Scenario 1 forecast based on the worst-case RAB investment requirement as discussed in Section 6.5.

Figure 4 Cumulative change in RAB in Scenario 1 by investment type



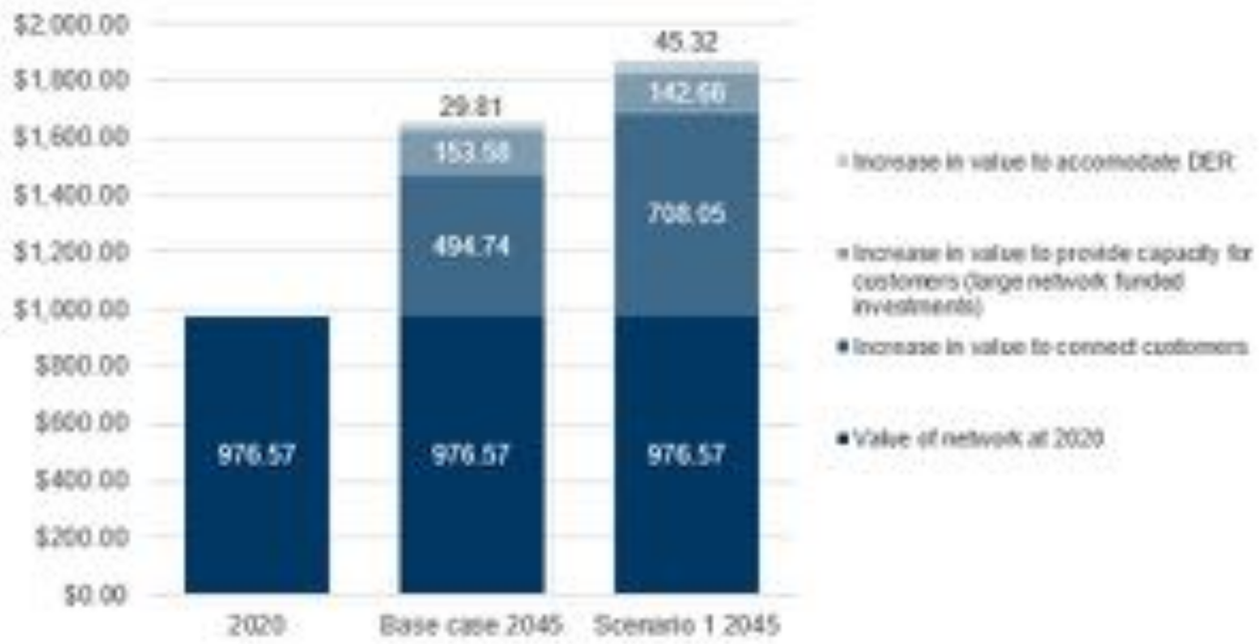
Source: GHD

[1] Underlying energy requirements (underlying demand) is defined as 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.
[2] Grid energy requirements (grid demand) is defined as all the electricity sourced from the Evoenergy network (the grid), at the point of the consumer's meter.
[3] Energy requirement (demand) is the total amount of electricity consumed over a period (in this case, a year) and is measured in gigawatt hours (GWh).
[4] Peak demand refers to the maximum amount of electricity used at any one time (in this case, a half hour period) and is measured in megawatts (MW). 50 'probability of exceedance' (POE) refers to the median or middle value in a range of peak demand outcomes that could be expected to occur.

1.2.3.6 Impact on network investment

Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The growth in demand has resulted in significant expenditure in both the non-specific investments and in the location specific projects (large material projects that will most be required to go through regulatory tests). The increase in location specific projects from 21 projects totalling $154 million up to 30 projects totalling $228 million (these figures include projects already underway) will result. The relative magnitude of the growth in the various segments of the network are shown in Figure 5.

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



Source: GHD

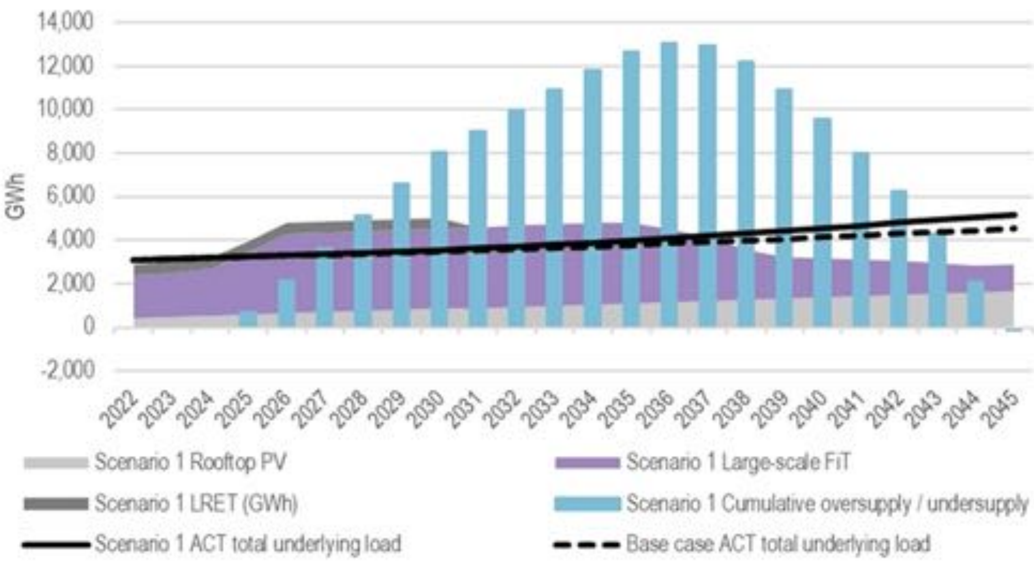
1.2.3.7 Delivering the 100% renewable electricity commitment

Scenario 1 incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable (like the base case). The projections show that the ACT will fall below the 100 per cent renewable mark from 2037, declining to around 57 per cent of underlying demand by 2045 (Figure 6). This indicates the government may need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is 'banked'. These 'banked' credits are carried forward and built into the cumulative oversupply/undersupply blue bars in the figure. These credits offset the need for additional purchases up until 2045.

1.2.3.8 Electricity bill impacts

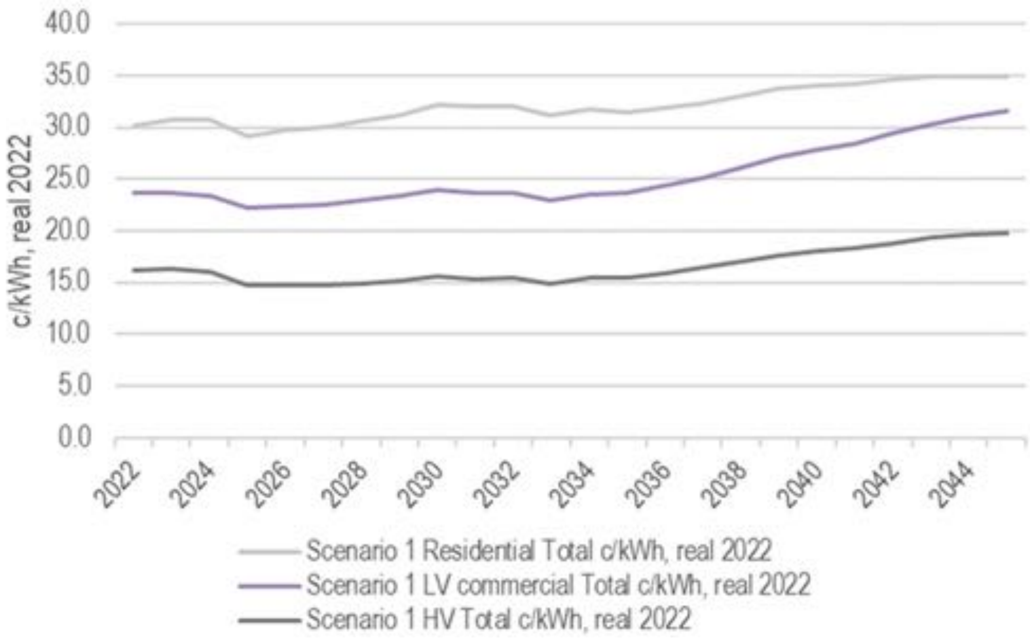
In Scenario 1, real retail prices for residential, LV commercial and HV customers are projected to increase by 16 per cent, 33 per cent and 22 per cent respectively over the period from 2022 to 2045 (see Figure 7). Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large-sale FiT payments over the period. Retail bills for residential, LV commercial and HV customers are projected to increase by 47 per cent, 32 per cent and 30 per cent, respectively over the period from 2022 to 2045, given growing average consumption by residential and LV customers in this scenario (primarily driven by electrification).

Figure 6 Projected contribution by category to 100% renewable energy (GWh) – Scenario 1 vs base case



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

Figure 7 Electricity retail prices – Scenario 1



Source: ACIL Allen

1.2.3.9 Costs and benefits to the ACT economy

In total, there are expected to be an additional $4.0 billion in costs (NPV7 of $1.6 billion) associated with the increased electricity usage compared to the base case (these costs do not include capital costs associated with additional energy efficiency technologies). In terms of benefits, Scenario 1 is expected to save ACT consumers $2.5 billion (NPV7 of $906 million) in gas and fuel costs. The net change in the direct costs of Scenario 1 is estimated to be +$1,482 million (or NPV7 of +$700 million). That is the benefits do not outweigh the costs. However, Scenario 1 will also result in a reduction of GHG emissions over the period to 2045 of 2,325 kt CO_2-e. Comparing the net cost of Scenario 1 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. The total undiscounted net cost of Scenario 1 implies a GHG emission abatement cost of +$637/t CO_2-e (NPV7 abatement cost of +$301/t CO_2-e). By comparison, in early 2022, emission allowances in the EU Emissions Trading System (EU ETS) were trading at around €80–100/t CO_2-e (equivalent to approximately A$120–160/t CO_2-e).

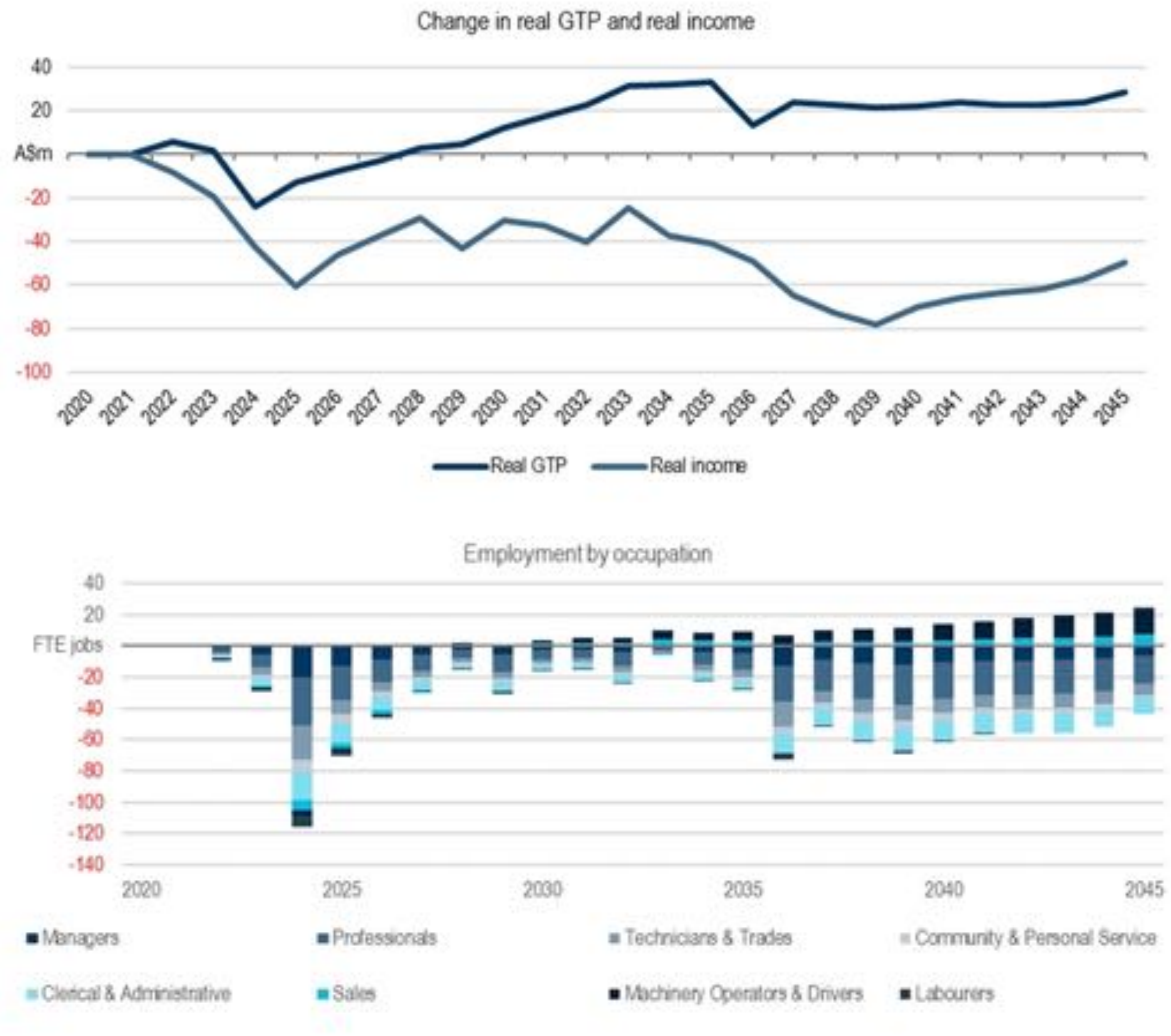
1.2.3.10 Macroeconomic impacts

Figure 8 shows the annual macroeconomic and employment impacts of Scenario 1 relative to the base case. The resultant cumulative difference of Scenario 1 over the period to 2045 is:

- +$340 million (or NPV7 of +$100 million) increase in the real GTP of the ACT, driven largely by the stimulus benefit of the additional capital expenditure and fuel savings from ZEVs outweighing the negative impact of higher electricity prices
- -$1,125 million (or NPV7 of -$474 million) change in the real income of ACT residents, driven by a longer-term loss in purchasing power and income transfers
- -834 employee years of employment (annual average change of -33 FTE jobs a year) in line with the lower real income. These job impacts are felt fairly uniformly across different occupations, except within the Machinery Operators & Drivers categories which experience a small net increase over the longer term.

While Scenario 1 results in a net increase in the real GTP of the ACT over the period, it comes at a significant cost to both real income and jobs.

Figure 8 *Annual macroeconomic impacts of Scenario 1, relative to the base case*



Source: ACIL Allen

1.3 Scenario 2: *Decentralisation is king*

1.3.1 Scenario description

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.

1.3.2 Key messages

- Under Scenario 2 and in line with projected gas consumption, emissions from the consumption of natural gas in the ACT are expected to fall from 350 kt of CO_2 to around 80 kt by 2045.
- Total consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045. This represents a decline of approximately 80%.

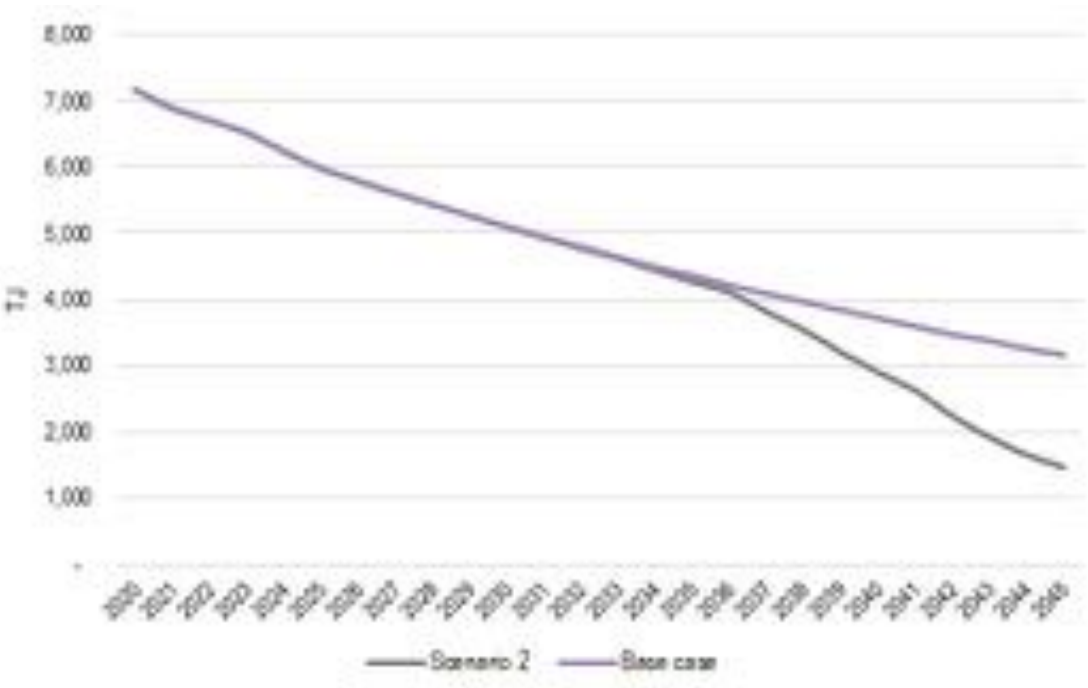
- Consumption tracks the base case and then steepens post 2035. From 2035 to 2045, the number of gas connections significantly fall.
- Decarbonisation of the gas sector strengthens later in the forecast period in comparison to Scenario 1. Switching rates are similar to that in Scenario 1 but increase more after 2040 in Scenario 2, where switching rates accelerate to 15%.
- The total delivered gas retail price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s. By 2045, gas prices are around 15 to 20% higher than in the base case.
- Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, the ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,553 GWh in 2045. This is a decline of around 8%, compared to an increase of 21% in the base case.
- Modelling indicates that the total increase in the RAB over the period 2020-2045 is approximately $899 million as opposed to the increase in RAB over the same time in the base case of $678 million. The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests).
- Compared to the base case scenario there is an increase in location specific projects from 21 projects totalling $154 million up to 23 projects totalling $208 million (these figures include projects already underway).
- Under Scenario 2 the ACT will fall below the 100% renewable mark from 2038, declining to around 73% by 2045. The government may need to factor in a further auction of renewable electricity around 2035, but ‘banked’ credits that are carried forward under the existing policy can offset the need for additional purchases beyond 2045.
- Electricity retail prices (real terms) for residential, LV commercial and HV customers are projected to increase by 48%, 35% and 21% respectively over the period from 2022 to 2045.
- Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large-scale FiT payments over the period.
- Scenario 2 delivers better renewable electricity outcomes, along with lower retail bill impacts in comparison with to Scenario 1. Compared to the base case, Scenario 2 incurs an additional $1.5 billion in costs (NPV7 of $497 million), while benefits will save ACT consumers $2.3 billion (or NPV7 of $842 million) in gas and fuel costs. The net change in direct costs is estimated to be -$780 million (or NPV7 of -$344 million). That is, the projected benefits clearly outweigh the costs included in the analysis.
- Scenario 2 results in a reduction of GHG emissions over the period to 2045 of 2,077 kt CO_2-e compared to the base case. The implied emission abatement cost of Scenario 2 is -$375/t CO_2-e, with an NPV7 abatement cost of -$166/t CO_2-e.
- Scenario 2 is the modelled case which delivers the best outcomes against all three macroeconomic indicators over the project period, relative to the base case. It delivers a +$1,224 million (or NPV7 of +$451 million) increase in the real GTP of the ACT; a -$165 million (or NPV7 of -$102 million) change in the real income of ACT residents; and -109 FTE employee years of employment (annual average change of -4 FTE jobs a year).

1.3.3 Key Results

1.3.3.1 Gas market projections

Total consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045. This represents a decline of approximately 80 per cent. This is compared with the base case in Figure 9. This scenario assumes gas consumption tracks the base case and then steepens post 2035. From 2035 to 2045, the number of gas connections will fall significantly fall. Under Scenario 2, decarbonisation of the gas sector strengthens later on in the forecast period in comparison to Scenario 1.

Figure 9 Projected total gas consumption – Scenario 2 vs base case



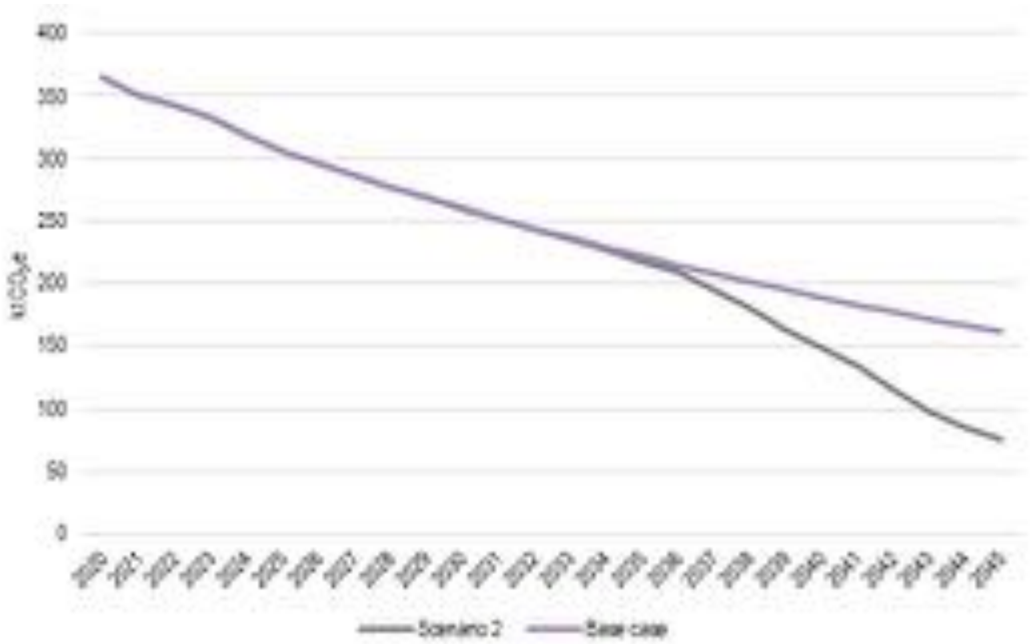
Source: ACIL Allen analysis

Switching rates are similar to that in Scenario 1 but increase more after 2040 in Scenario 2, where switching rates accelerate to 15 per cent. This means 1 in 7 households post 2040 are switching to electricity from gas. Prior to 2040 the rate is much slower - around 1 in 50 gas connections moving to electricity in the 2020s, accelerating to around 1 in 30 in the 2030s.

1.3.3.2 Implications for GHG emissions

Under Scenario 2 and 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 350 kt of CO_2. This would reduce to levels around 80 kt by 2045. The emission reduction for Scenario 2 against the base case is indicated at Figure 10.

Figure 10 Natural gas projected emissions – Scenario 2 vs base case



Source: ACIL Allen analysis

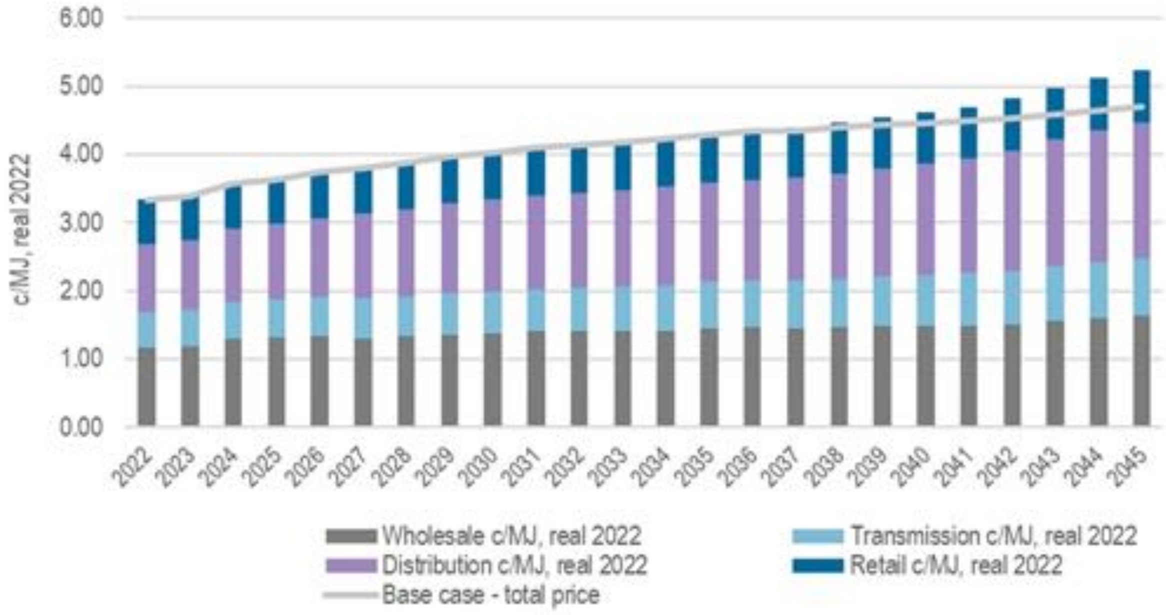
1.3.3.3 Gas retail price

The total delivered retail price projected over the projection period is presented below in Figure 11.

The price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s. This means for a household consuming around 35 GJ per annum, their residential gas bill would increase from around $1,155 per annum to levels just shy of $1,820 per annum.

The trajectory is similar to that of the base case until late in the 2030s where prices are expected to increase more rapidly as gas connections fall more steeply. By 2045, gas prices are around 15 to 20 per cent higher than in the base case.

Figure 11 ACT retail price for natural gas delivered to residential customers



Source: ACIL Allen

1.3.3.4 Electricity market modelling

Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, the ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,553 GWh in 2045, which is a decline of around eight per cent over the projection period, compared to an increase of 21 per cent in the base case. ACT 50POE peak grid demand is projected to grow from 654 MW in 2022 to 1,048 MW in 2045, which is an increase of around 60 per cent over the projection period, compared to 48 per cent in the base case.

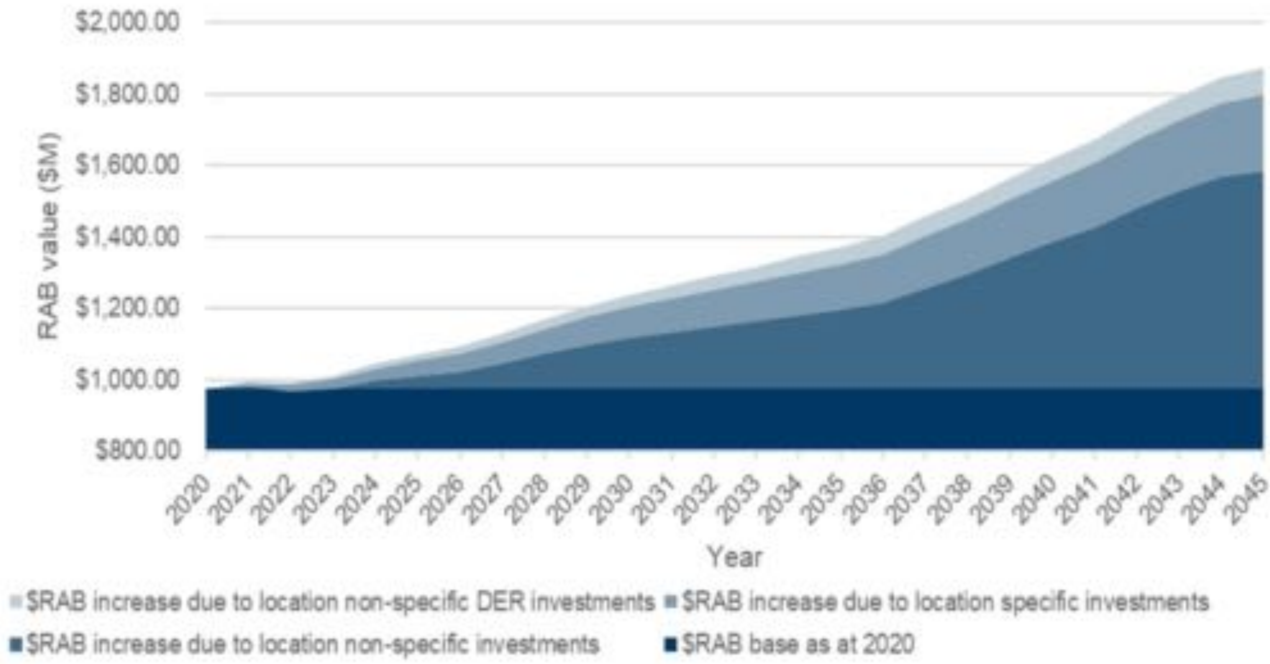
Key factors encompassed in this decline of eight per cent include:

- delivery of 47 per cent of total energy requirements through rooftop PV by 2045
- ZEVs comprise 68 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 behind-the-meter storage on the demand profile is reasonably small given the level of uptake projected
- taking out 20 per cent more gas consumption (from 60 per cent by 2045 in the base case to 80 per cent by 2045 in Scenario 2) only increases electricity energy requirements by 176 GWh by 2045 or seven per cent of total grid energy requirements by 2045
- taking out 20 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 273 MW by 2045 or 26 per cent of total peak demand by 2045.

1.3.3.5 Electricity system network analysis

The Scenario 2 demand forecast will require investment of an additional $899 million in the network to 2045 (up from the 2020 valuation of $1,876 million). Figure 12 shows the change in the RAB by type of investment in the Scenario 2 forecast based on the worst-case RAB investment requirement as discussed in Section 7.5.

Figure 12 Cumulative change in RAB in Scenario 2 by investment type



Source: GHD

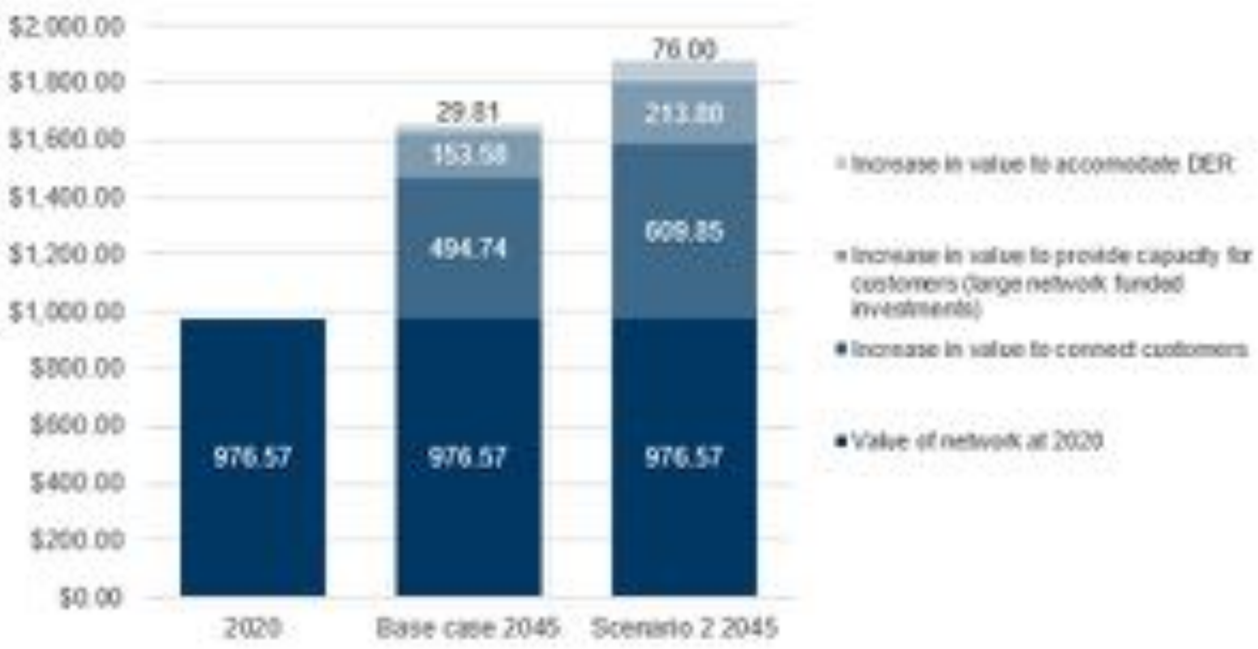
1.3.3.6 Impact on network investment

The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests).

Compared to the base case scenario there is an increase in location specific projects from 21 projects totalling $154 million up to 23 projects totalling $208 million (these figures include projects already underway).

The relative magnitude of the growth in the various segments of the network are indicated at Figure 13.

Figure 13 Change in value of the distribution asset base 2020-2045, $ million

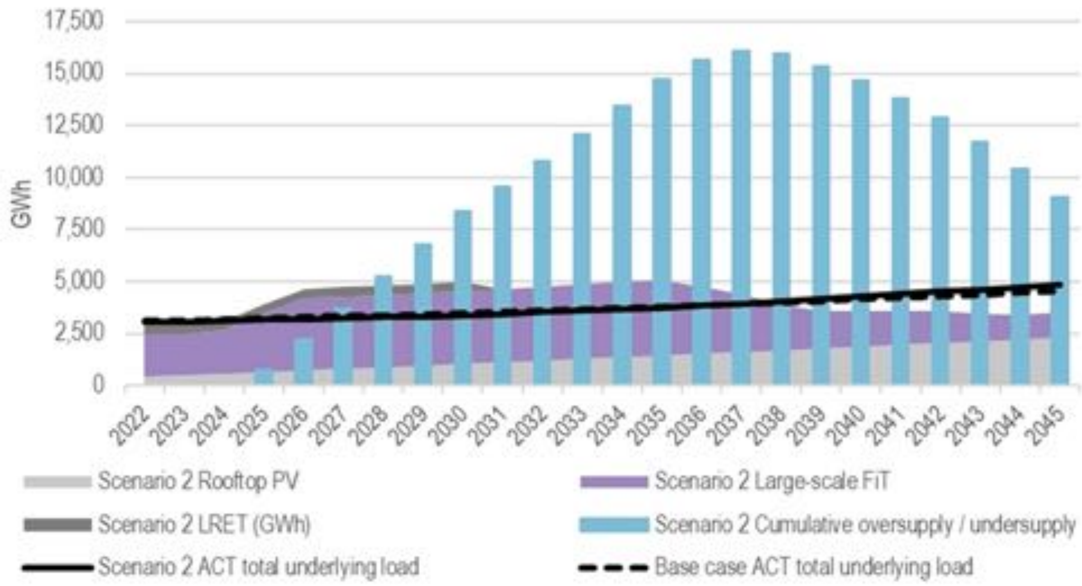


Source: GHD

1.3.3.7 Delivering the 100% renewable electricity commitment

Scenario 2 incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable (like the base case). The projections show that the ACT will fall below the 100 per cent renewable mark from 2038, declining to around 73 per cent of underlying demand by 2045 (Figure 14).

Figure 14 Projected contribution by category to 100% renewable energy (GWh) – Scenario 2 vs base case



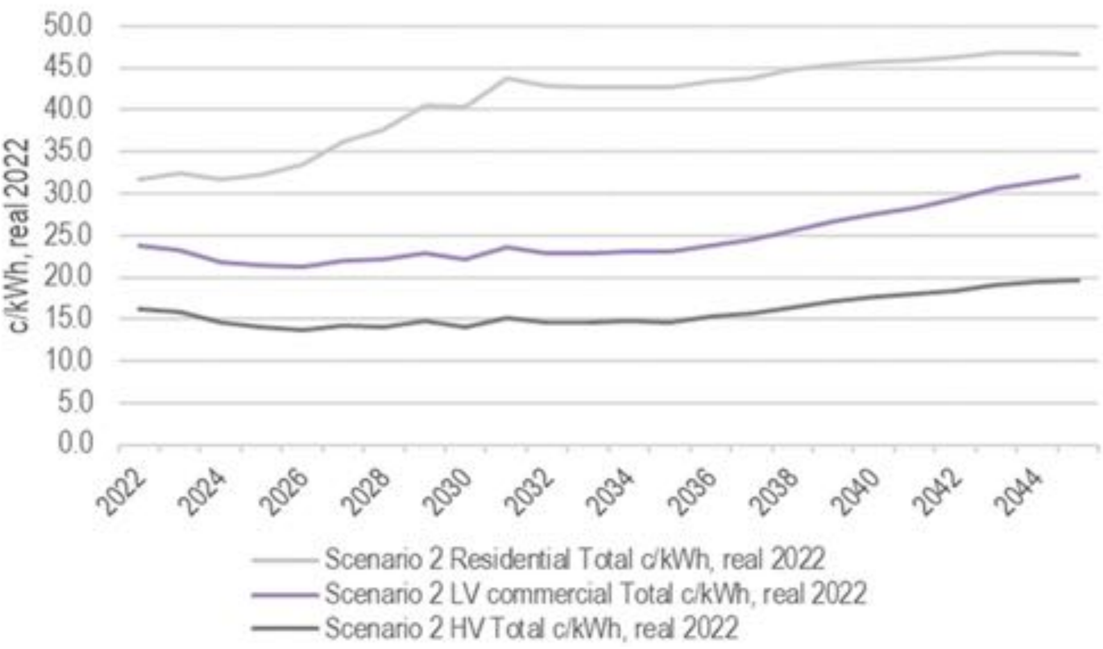
Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis

This indicates the government may need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is 'banked'. These 'banked' credits are carried forward and built into the cumulative oversupply/undersupply blue bars in the figure. These credits offset the need for additional purchases beyond the 2045 period.

1.3.3.8 Electricity bill impacts

In Scenario 2, real retail prices for residential, LV commercial and HV customers are projected to increase by 48 per cent, 35 per cent and 21 per cent respectively over the period from 2022 to 2045 (see Figure 15). Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large-scale FiT payments over the period. Scenario 2 delivers better renewable electricity outcomes, along with lower retail bill impacts in comparison with to Scenario 1.

Figure 15 Electricity retail prices – Scenario 2



Source: ACIL Allen

1.3.3.9 Costs and benefits to the ACT economy

In total, there are expected to be an additional $1.5 billion in costs (or NPV7 of $497 million) associated with the increased electricity usage, compared to the base case. In terms of benefits, Scenario 2 is expected to save ACT consumers $2.3 billion (or NPV7 of $842 million) in gas and fuel costs compared to the base case.

The net change in the direct costs of Scenario 2 compared to the base case is estimated to be -$780 million (or NPV7 of -$344 million). That is, the projected calculated benefits outweigh the calculated costs included here. In addition to the benefits, Scenario 2 will also result in a reduction of GHG emissions over the period to 2045 of 2,077 kt CO_2-e compared to the base case.

Comparing the net cost of Scenario 2 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. The total undiscounted net cost of Scenario 2 implies a GHG emission abatement cost of -$375/t CO_2-e, with an NPV7 abatement cost of -$166/t CO_2-e.

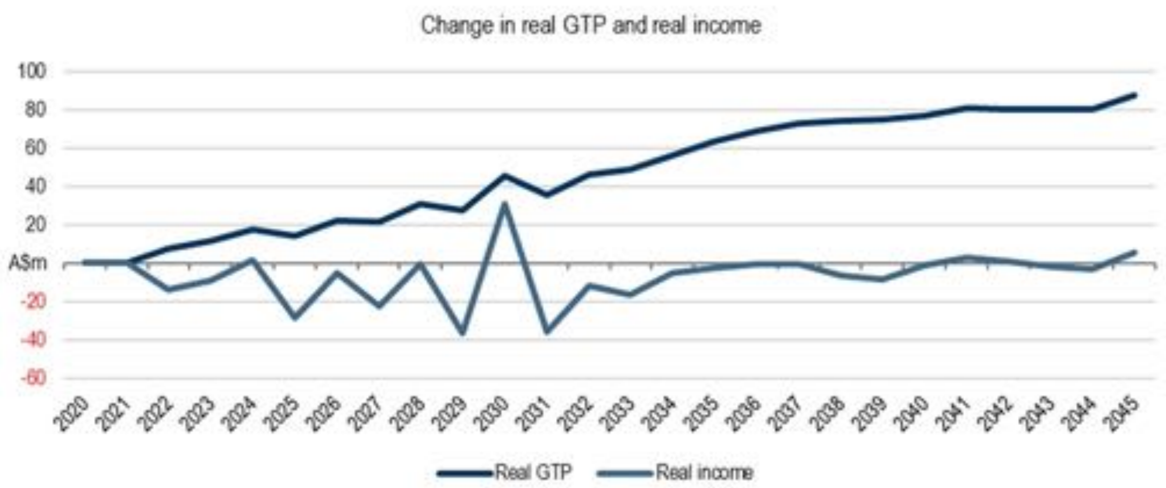
1.3.3.10 Macroeconomic impacts

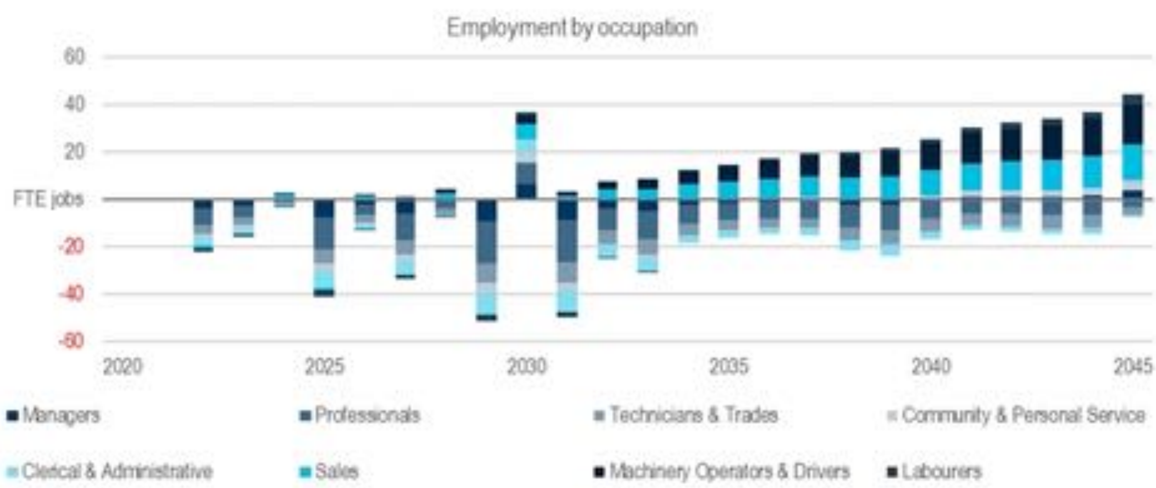
Figure 16 shows the annual macroeconomic and employment impacts of Scenario 2 relative to the base case. The resultant cumulative difference of Scenario over the period to 2045 is:

- +$1,224 million (or NPV7 of +$451 million) increase in the real GTP of the ACT, driven largely by the stimulus benefit of the cheaper electricity and energy savings from energy efficiency improvements
- -$165 million (or NPV7 of -102 million) change in the real income of ACT residents
- -109 FTE employee years of employment (annual average change of -4 FTE jobs a year) in line with the higher real income.

Scenario 2 is the modelled case which delivers the best outcomes against all three macroeconomic indicators over the projection period, delivering an increase in the real GTP of the ACT; the smallest change in the real income of ACT residents; and a near zero change in average annual employment.

Figure 16 Annual macroeconomic impacts of Scenario 2, relative to the base case





Source: ACIL Allen

1.4 Scenario 3: *Policy drives change*

1.4.1.1 Scenario description

The *Policy drives change* 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.

1.4.1.2 Key messages

Scenario 3 delivers the best emission reduction outcomes with CO_2 emissions from natural gas coupled with the best overall renewable electricity delivery. The total natural gas consumption would reduce from around 7,000 TJ to zero in 2035; and the estimated natural gas emissions would reduce from around 350 kt of CO_2 to zero tonnes by 2035.

The total delivered gas retail price projected over the projection period will increase in real terms from levels around 3.3 cents/MJ to levels around 9 cents/MJ by 2032, and to levels beyond 15 cents/MJ by 2033. The incentive for gas customers to switch will need to be high or regulations introduced to prohibit gas appliances (with a transition period given for customers to switch to electrical appliances).

Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification the ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,406 GWh in 2045. This is a decline of around 13%, compared to an increase of 21% in the base case.

Scenario 3 requires the highest level on new investment (RAB) in the grid. Modelling indicates the total increase in the RAB over the period 2020-2045 is approximately $1,093 million as opposed to the increase in RAB over the same time in the base case of $678 million.

Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The resultant impact will be an increase in location specific projects from 21 projects totalling $154 million up to 32 projects totalling $251 million (these figures include projects already underway).

The overall impact on electricity retail bills is on a par with the best outcomes delivered by other scenarios. Even though retail prices under Scenario 3 are some of the highest (mainly due to high distribution network costs), the low average consumption reduces the overall bill impact. Strong policy and regulatory drivers will be required to achieve these scenario outcomes.

Compared to the base case, Scenario 3 incurs an additional $10.1 billion in costs (NPV7 of $4.4 billion), while benefits will save ACT consumers $4.4 billion (or NPV7 of $1.6 billion) in gas and fuel costs. The net change in direct costs is estimated to be +$5,672 million (or NPV7 of +$2,779 million). That is, the projected costs included in the analysis clearly outweigh the benefits.

Scenario 3 results in a reduction of GHG emissions over the period to 2045 of 5,012 kt CO_2-e compared to the base case (more than double that achieved in Scenarios 1 and 2). The implied emission abatement cost of Scenario 3 is +$1,132/t CO_2-e, with an NPV7 abatement cost of +$554/t CO_2-e.

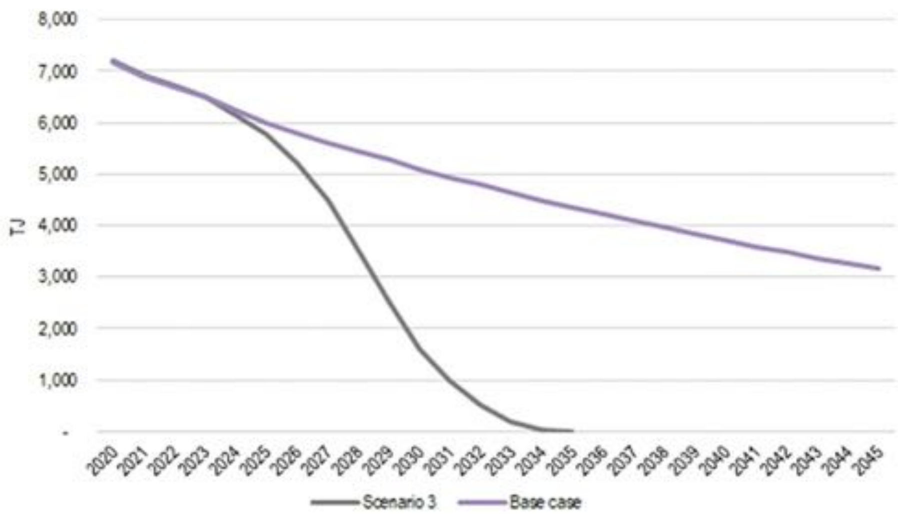
Scenario 3 has the highest additional net costs, resulting in negative net outcomes against all three macroeconomic indicators over the projection period, with a substantial fall in the real GTP of the ACT; a major drop in the real income of ACT residents; and generating significantly less employment.

1.4.2 Key results

1.4.2.1 Gas market projections

Under Scenario 3, total natural gas consumption in the ACT is expected to drop from levels around 7,000 TJ currently to zero in 2035. Associated consumption and connections decline rapidly post the current access arrangement period as indicated at Figure 17.

Figure 17 Projected total gas consumption, ACT – Scenario 3 vs base case

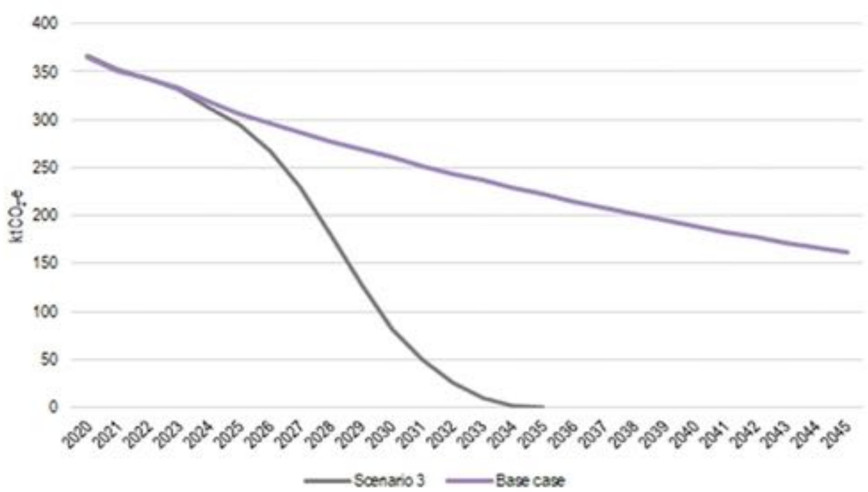


Source: ACIL Allen analysis

1.4.2.2 Implications for GHG emissions

Under Scenario 3, estimated natural gas emissions are currently around 350 kt of CO_2. This would reduce to zero tonnes by 2035. Natural gas emissions against the base case are presented below in Figure 18.

Figure 18 Natural gas projected emissions – Scenario 3 vs base case

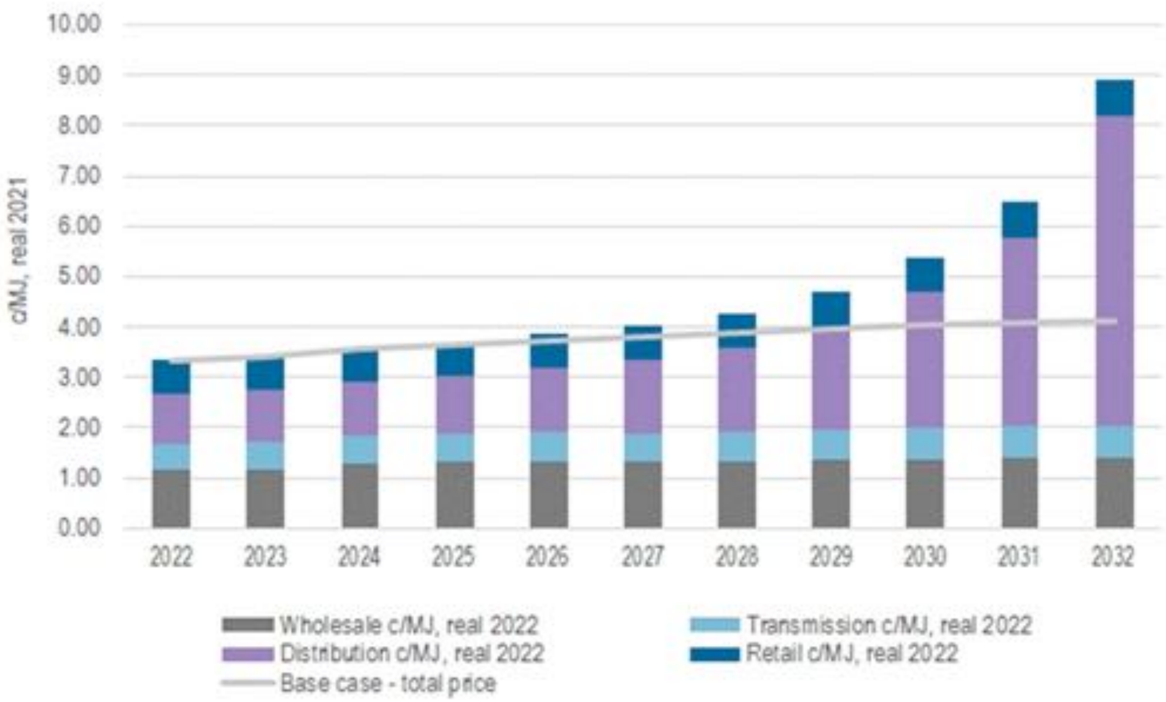


Source: ACIL Allen analysis

1.4.2.3 Gas retail price

The total delivered retail price projected over the projection period is presented below in Figure 19. The price increases in real terms from levels around 3.3 cents/MJ to levels around 9 cents/MJ by 2032, and to levels beyond 15 cents/MJ by 2033. Beyond 2033, prices increase dramatically. Meaning that, from the late 2020s, gas prices will be significantly higher for consumers, compared to the base case.

Figure 19 ***ACT retail price for natural gas delivered to residential customers – Scenario 3 vs base case***



Source: ACIL Allen analysis

1.4.2.4 Electricity market modelling

Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, the ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,406 GWh in 2045. This is a decline of around 13 per cent over the projection period, compared to an increase of 21 per cent in the base case. ACT 50POE peak grid demand is projected to grow from 654 MW in 2022 to 1,143 MW in 2045, which is an increase of around 75 per cent over the projection period, compared to 48 per cent in the base case.

Key factors encompassed in this decline of around 13 per cent include:

- delivery of 51 per cent of total energy requirements through rooftop PV by 2045
- ZEVs comprise 68 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 behind-the-meter storage on the demand profile is reasonably small given the level of uptake projected

- taking out 40 per cent more gas consumption (from 60 per cent by 2045 in the base case to 100 per cent by 2045 in Scenario 3) only increases electricity energy requirements by 313 GWh by 2045 or 13 per cent of total grid energy requirements by 2045
- taking out 40 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 385 MW by 2045 or 34 per cent of total peak demand by 2045.

1.4.2.5 Electricity system network analysis

The results of the modelling show that the total increase in the RAB over the period 2020-2045 is approximately $1,093 million as opposed to the increase in RAB over the same time in the base case of $678 million. Figure 20 shows the change in the RAB by type of investment in the Scenario 3 forecast based on the worst-case RAB investment requirement as discussed in Section 8.5.

Figure 20 Cumulative change in RAB in Scenario 3 by investment type

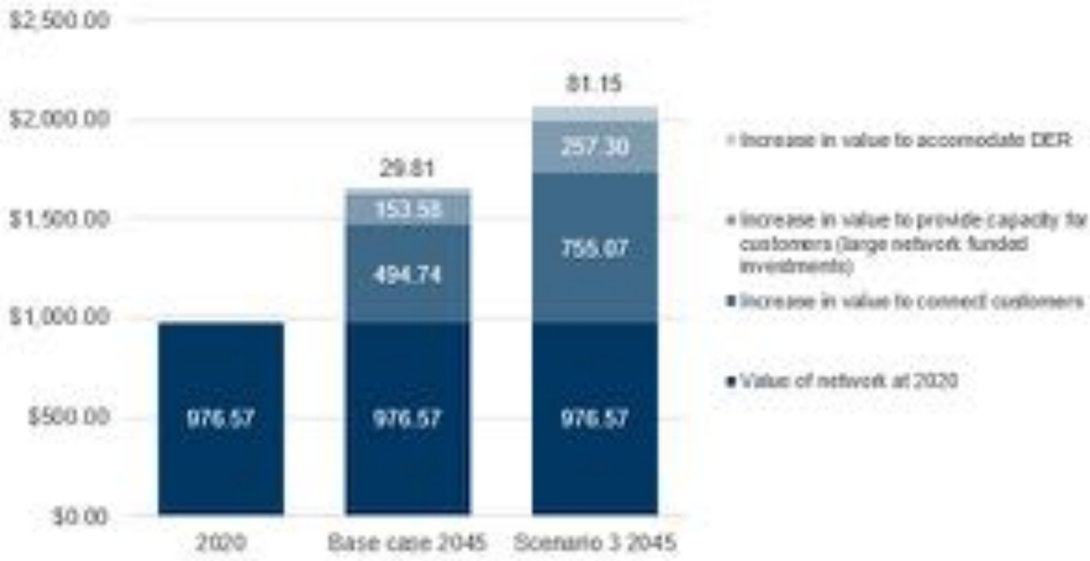
Source: GHD

1.4.2.6 Impact on network investment

Compared to the base case for Scenario 3, there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The growth in demand will result in significant expenditure in both the non-specific investments and in the location specific projects.

The resultant impact (compared to the base case scenario) will be an increase in location specific projects from 21 projects totalling $154 million up to 32 projects totalling $251 million (these figures include projects already underway). The relative magnitude of the growth in the various segments of the network are indicated at Figure 21.

Figure 21 Change in value of the distribution asset base 2020-2045, $ million

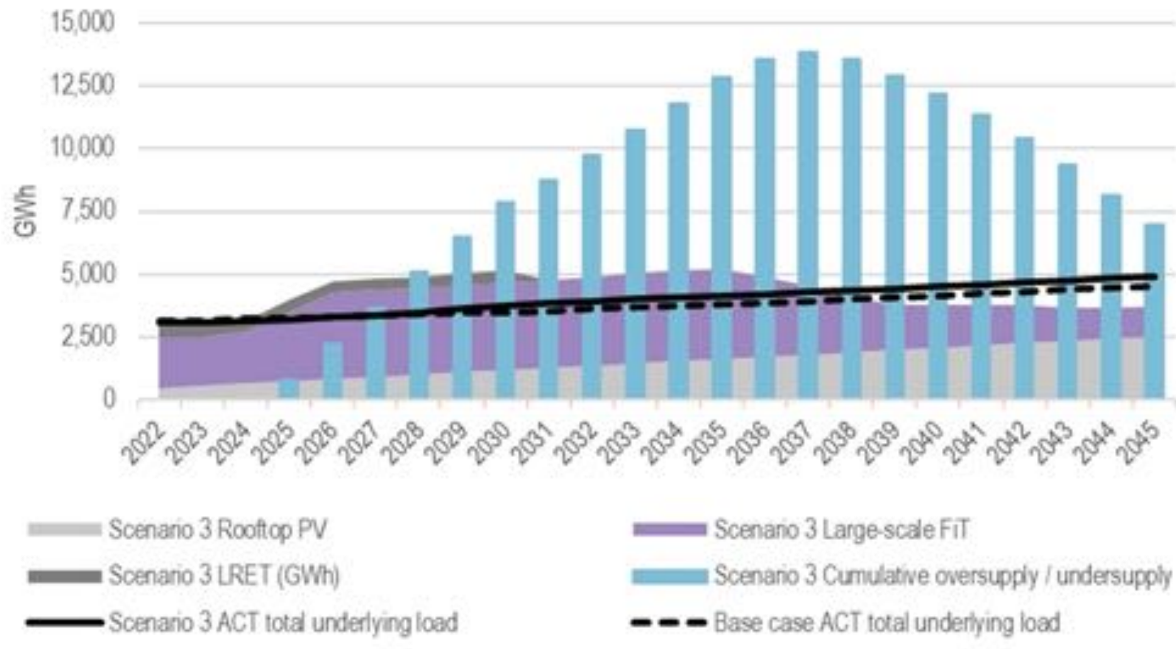


Source: GHD

1.4.2.7 Delivering the 100% renewable electricity commitment

Scenario 3 incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable (like the base case). The projections show that the ACT will fall below the 100 per cent renewable mark from 2038, declining to around 76 per cent of underlying demand by 2045 (Figure 22). This indicates the government may need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is ‘banked’. These ‘banked’ credits are carried forward and built into the cumulative oversupply/undersupply blue bars in the figure. These credits offset the need for additional purchases beyond the 2045 period.

Figure 22 Projected contribution by category to 100% renewable energy (GWh) – Scenario 3 vs base case



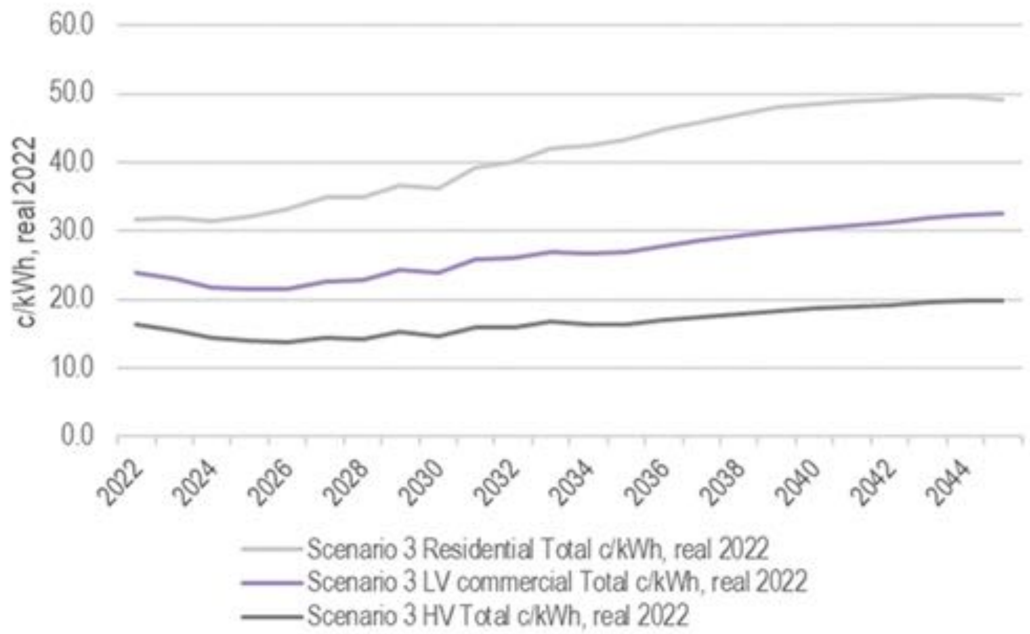
Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis:

1.4.2.8 Electricity bill impacts

Over the period to 2030, projected retail bills for residential, LV commercial and HV customers are projected to decline in real terms by six per cent, increase by one per cent and decline by 10 per cent, respectively (see Figure 23). This is the result of the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes as well as falling average consumption per customer, offsetting projected increase in transmission and distribution network costs.

From 2030 to 2045, projected retail bills for residential, LV commercial and HV customers increase by 10 per cent, 20 per cent and 30 per cent, respectively. These increases reflect the projected increase in wholesale and distribution network costs, which are only partially offset by the projected decline in large FiT payments and transmission network costs.

Figure 23 Electricity retail prices – Scenario 3



Source: ACIL Allen

1.4.2.9 Costs and benefits to the ACT economy

In total, there are expected to be an additional $10.1 billion in costs (NPV7 of $4.4 billion) associated with the increased electricity usage, offset by saving to ACT consumers of $4.4 billion (or NPV7 of $1.6 billion) in gas and fuel costs, compared to the base case. Estimated costs and benefits are both substantially higher than in Scenarios 1 and 2, with costs driven by the need to undertake significant upgrades and changes to the electricity network to ensure security of supply whilst the rapid electrification transition occurs, and benefits accruing from the reduction in natural gas usage (which falls to zero by 2035). The net change in the direct costs (compared to the base case) is estimated to be +$5,672 million (or NPV7 of +$2,779 million), that is costs significantly outweigh the benefits. Scenario 3 also result in a reduction of GHG emissions over the period of 5,012 kt CO_2-e compared to the base case, which is more than double the additional GHG emissions reduction achieved in Scenarios 1 and 2. Comparing the net cost of Scenario 3 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. The total undiscounted net cost of Scenario 3 implies a GHG emission abatement cost of +$1,132/t CO_2-e, with an NPV7 abatement cost of +$554/t CO2-e.

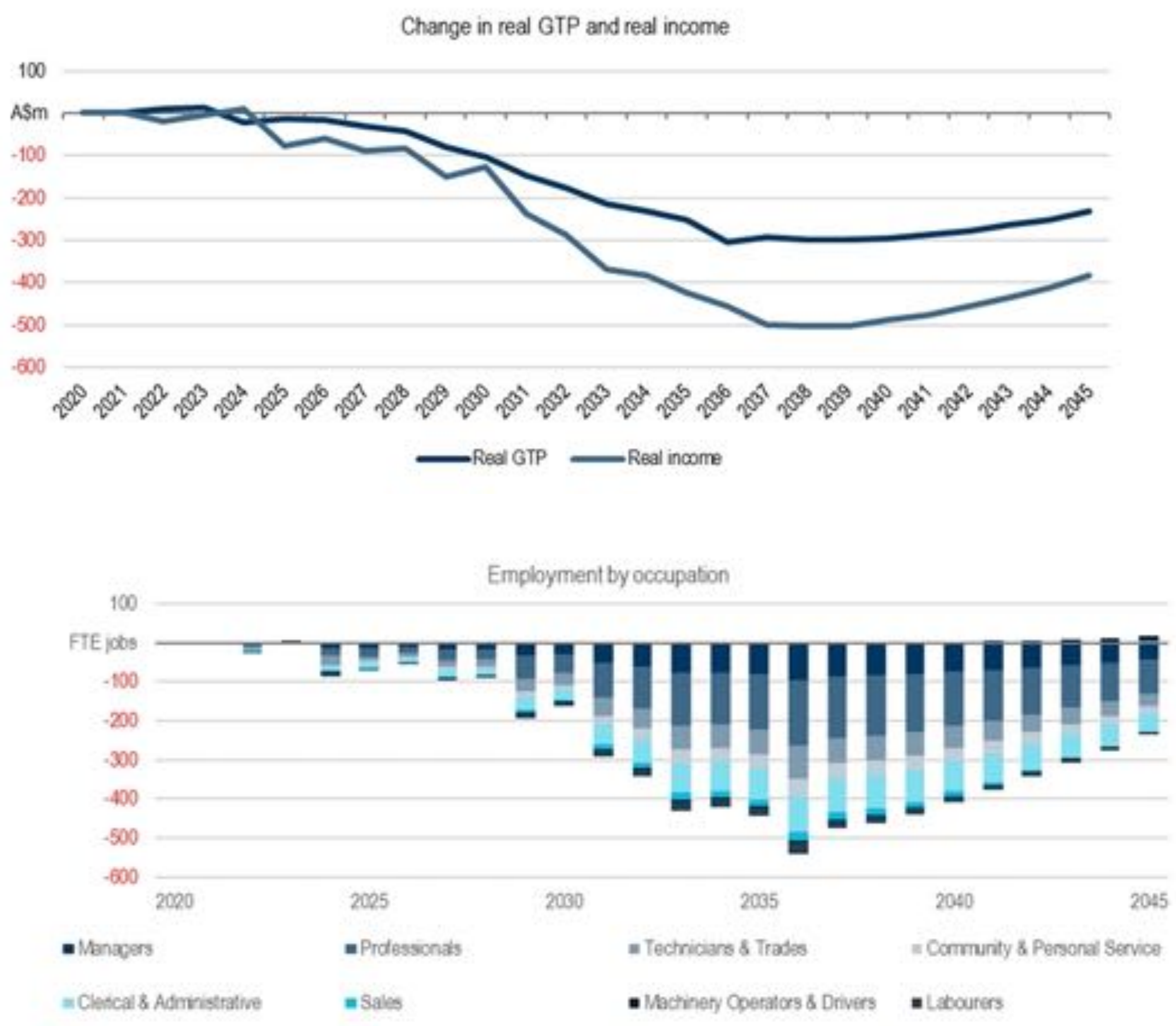
1.4.2.10 Macroeconomic impacts

Figure 24 shows the annual macroeconomic and employment impacts of Scenario 3 relative to the base case. The resultant cumulative difference of Scenario 3 over the period to 2045 is:

- -$4,106 million (or NPV7 of -$1,390 million) change in the real GTP of the ACT - while initially there is little net impact due to the large additional capital program , it becomes negative in the longer term due to the longer-term cost of the investment relative to the benefits and the crowding out of other investments
- -$6,910 million (or NPV7 of -$2,397 million) change in the real income of ACT residents
- -6,150 FTE employee years of employment (annual average change of -260 FTE jobs a year) in line with the lower real income.

Scenario 3 has the highest additional net costs, resulting in negative net outcomes against all three macroeconomic indicators over the projection period, with a substantial fall in the real GTP of the ACT; a major drop in the real income of ACT residents; and generating significantly less employment.

Figure 24 Annual macroeconomic impacts of Scenario 3, relative to the base case

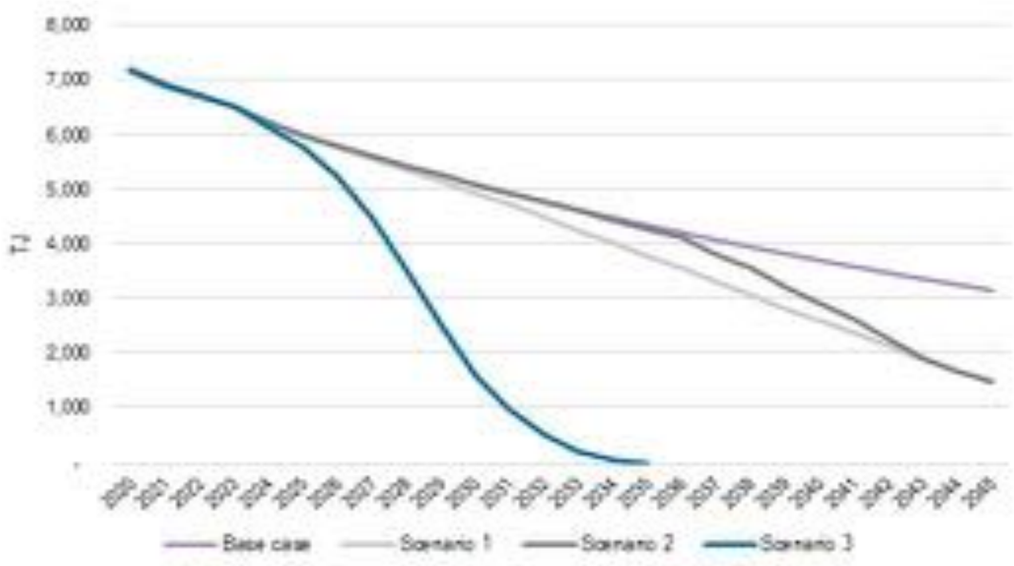


Source: ACIL Allen

1.5 Scenario versus base case comparison summary

Modelling indicates that under all (3) scenarios natural gas use is expected to decline relative to the base case (see Figure 25). The base case sees gas demand from the network drop by 60 per cent with no overall network growth given Government policy. Scenarios 1 and 2 look to increase this downwards trend resulting in an 80 per cent reduction in gas demand by 2045. Under Scenario 2, the decrease follows the base case trajectory until 2035, but then falls away more rapidly (in comparison to Scenario 1). Scenario 3 sees the natural gas network close by 2035.

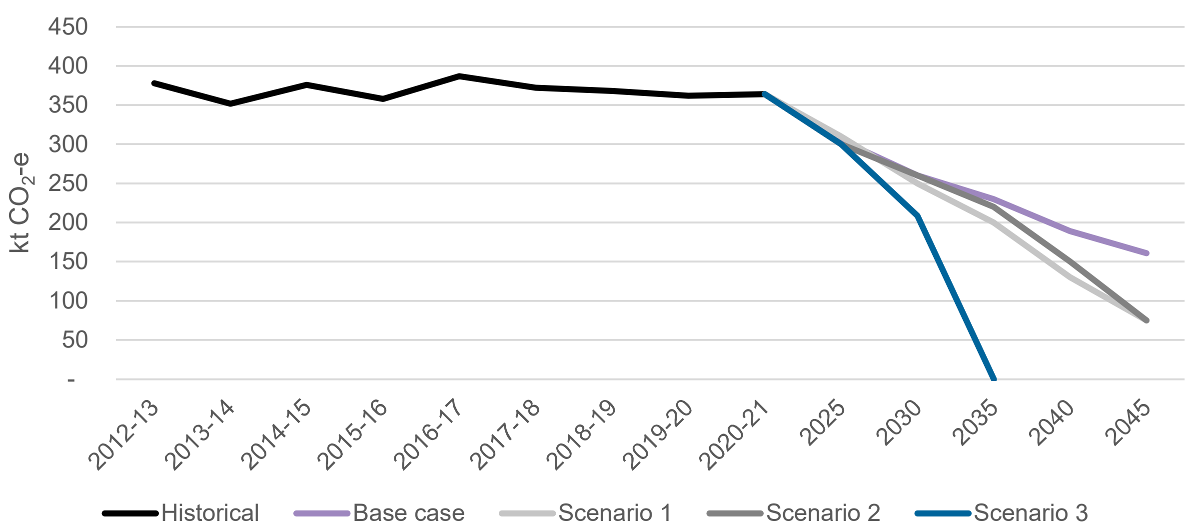
Figure 25 Projected total natural gas consumption – all scenarios vs base case



Source: ACIL Allen analysis

The decline in natural gas consumption under all (3) scenarios natural gas will result in a corresponding fall in greenhouse gas emissions as indicated at Figure 26. Scenario 1 and Scenario 2 show a significant gain in comparison to the base case, with both generating an additional cut in emissions of around 85 kt by 2045. Scenario 3 sees emissions from the natural gas network reducing more rapidly and falling to zero from 2035.

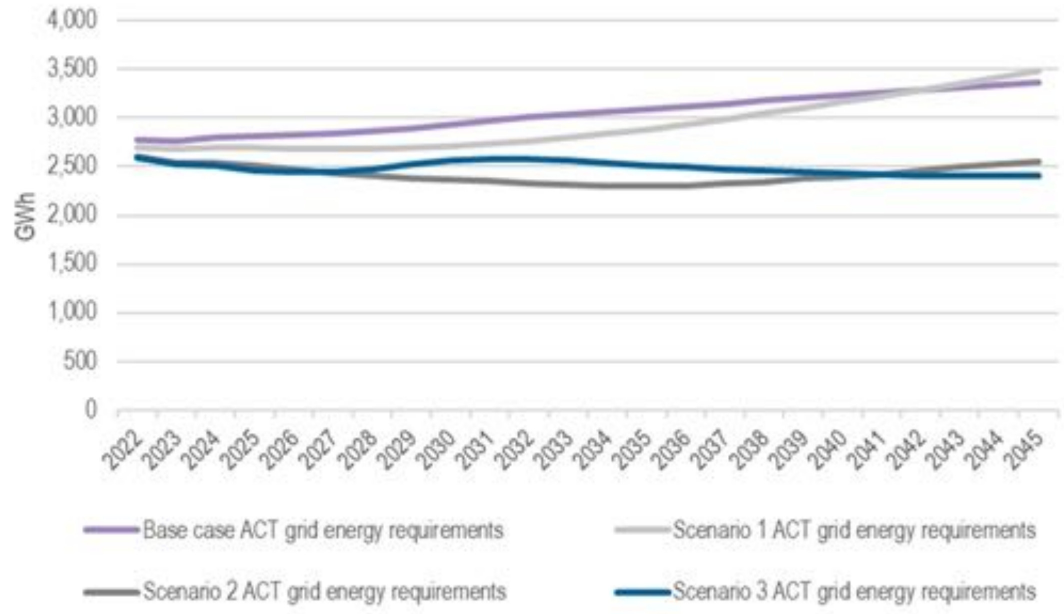
Figure 26 Projected ACT emissions from gas – all scenarios vs base case

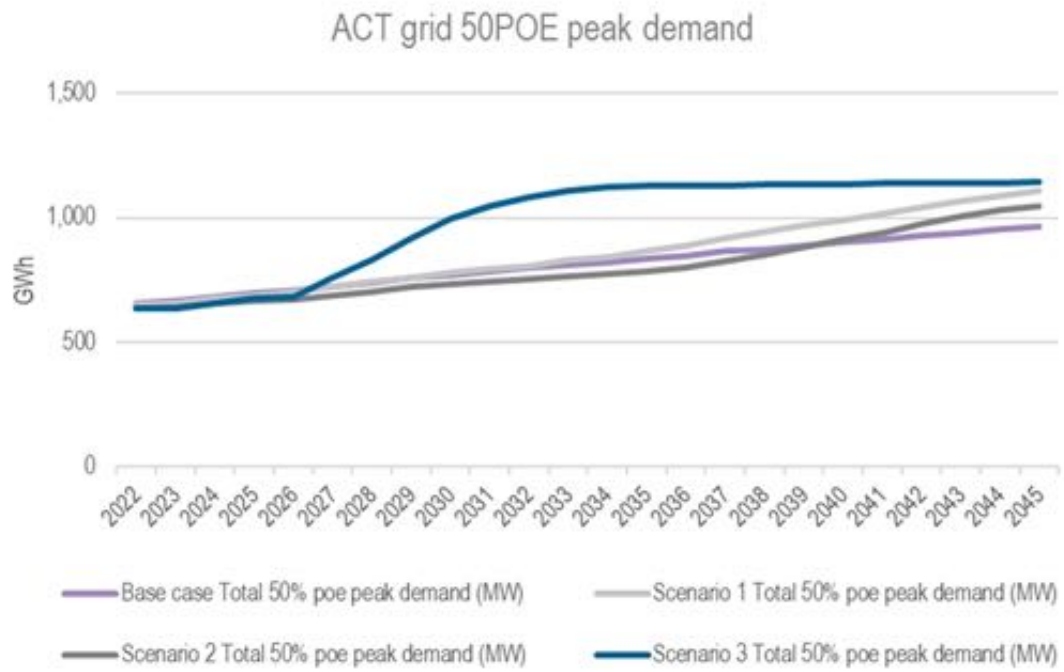


Source: ACIL Allen, GHD

The projected annual (grid) energy requirements differ between scenarios as illustrated at Figure 27. Both the base case and Scenario 1 trend upwards reflecting overall demand, albeit Scenario 1 rises at a slower rate, reflecting greater PV deployment. There is an estimated 26 per cent increase against the base case for Scenario 1 (from 2,772 GWh in 2022 to 3,481 GWh in 2045). Grid energy requirements under both Scenarios 2 and 3 remain essential flat with demand offset by greater PV penetration and energy efficiency improvements. Scenario 2 would see a decline in total grid energy requirements at eight per cent (from 2,772 GWh in 2022 to 2553 GWh in 2045) whilst Scenario 3 (from 2,772 GWh in 2022 to 2406 GWh in 2045) would deliver a 13 per cent fall.

Figure 27 Projected total annual grid energy requirements (demand) – all scenarios vs base case

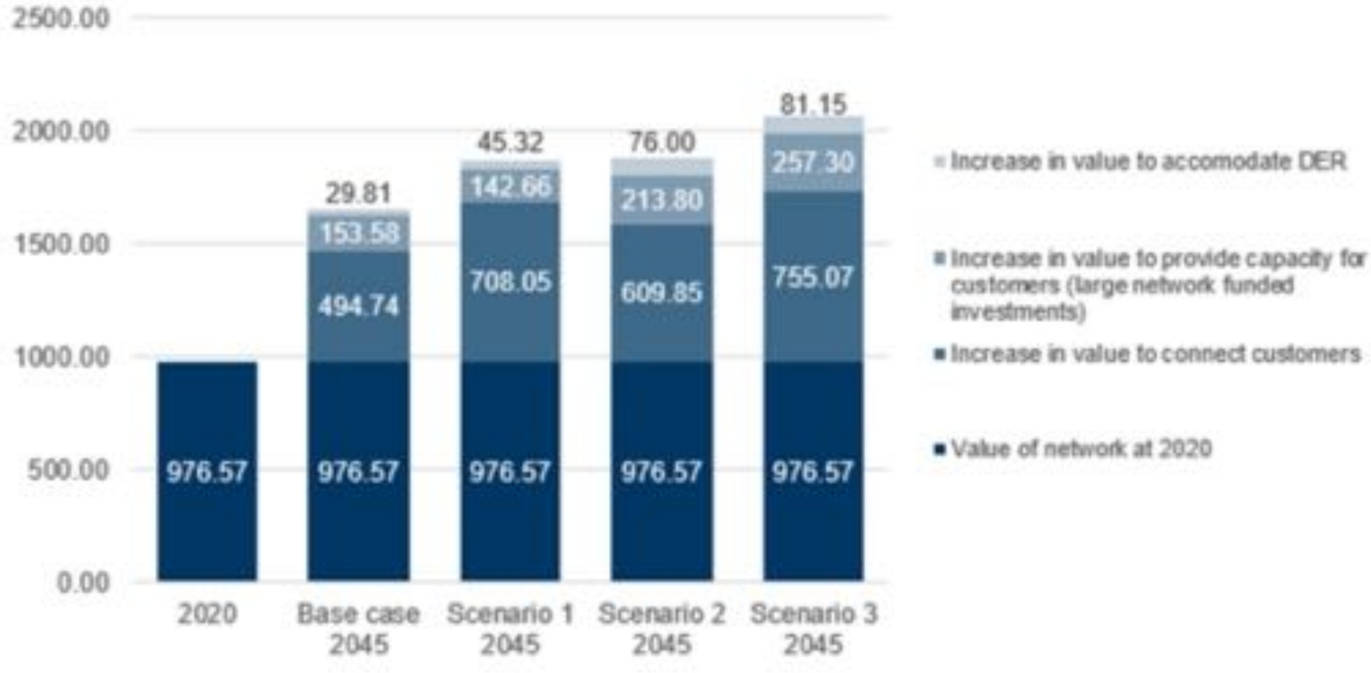




Note: Grid energy requirements (grid demand) refers to the electricity sourced from the grid, measured at the point of the consumer's meter.
Source: ACIL Allen

Investment in the electricity system will be required under all scenarios to maintain the existing level of safety, quality, reliability, and security of supply to energy users. The comparison of change required in the network RAB is indicated at Figure 28 below based on the worst-case RAB investment requirement as discussed in Section 9.1.2.

Figure 28 ***Change in value of the distribution asset base 2020-2045, $ million***



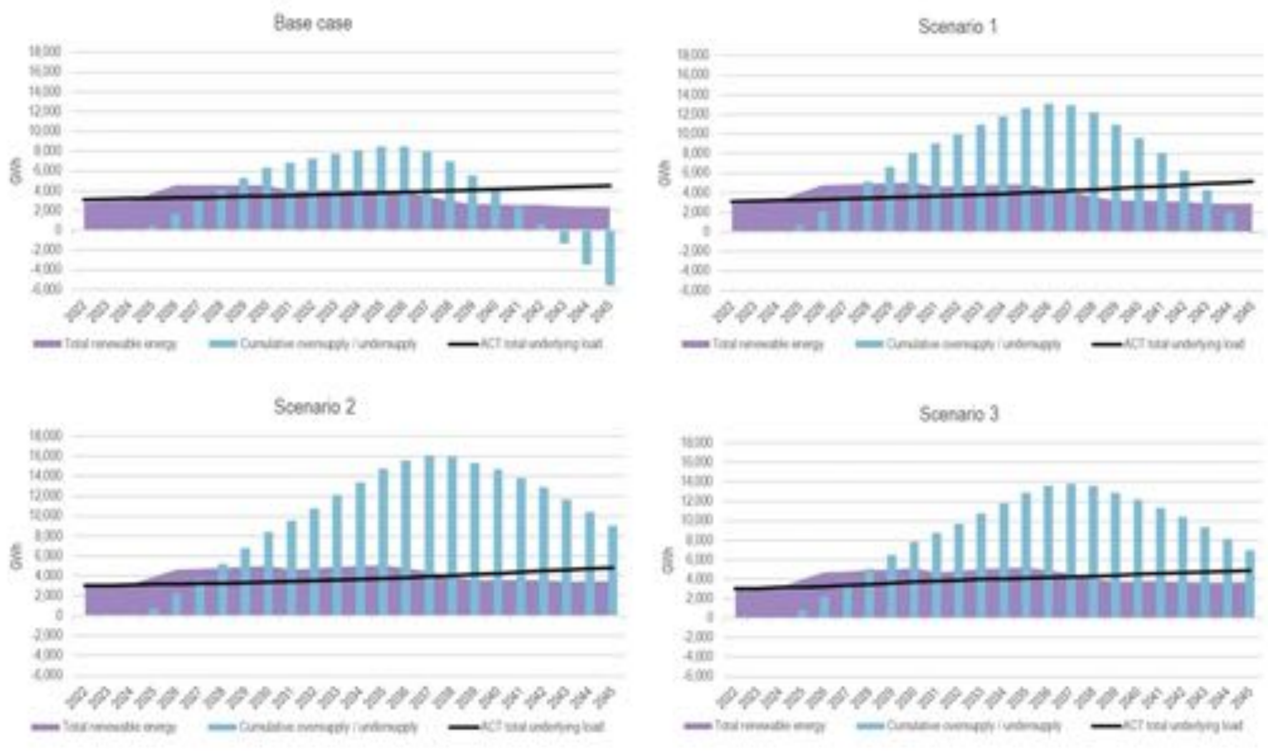
Source: GHD

The faster gas transition in all scenarios drives higher network investment expenditure, given additional infrastructure is required to meet the rising demands. In Scenario 3 where transition is most rapid the investment in the network is more significant than in the other cases. All scenarios indicate significant growth in DER which has contributed to the significant investment in the network to ensure that they can connect without having an adverse effect on the supply to customers.

To maintain the 100 per cent renewable electricity commitment the base case and the three scenarios all incorporate a third auction in 2025 (assumed to be two 200 MW wind farms in NSW) to ensure the Government delivers its commitment. Taking into account the current policy, which allows renewable electricity in excess of the 100 per cent target to be ‘banked’, with credits carrying over to future years, all scenarios ‘deliver’ against the commitment shown at Figure 29, with the base case falling slightly short at the end of the period.

While the base case falls short from 2043, the National Electricity Market (NEM) is projected to source more of its generation from renewables over time which will more than offset the shortfall (if the policy is changed to allow the NEM’s contribution to be considered). Furthermore, a policy change of this nature would allow reconsideration of the timing and magnitude of the 2025 auction, particularly under Scenarios 2 and 3.

Figure 29 *Meeting the 100% renewable electricity commitment – all scenarios*



Source: ACIL Allen

Residential bills are projected to be lowest under Scenario 2 due to lower projected average consumption per customer (driven by higher assumed levels of energy efficiency and rooftop PV uptake), which offsets higher projected retail prices (see Figure 30). Scenario 3 retail bills have similar drivers to Scenario 2 (lower average consumption offsetting the higher cost per unit of consumption). However, between around 2028 and 2042, Scenario 3 bills are higher than Scenario 2, given a significant amount of electrification is assumed to brought forward in Scenario 3.

Figure 30 *Residential electricity bill – all scenarios*

Source: ACIL Allen

On the other hand, residential bills are projected to be highest under Scenario 1 due to a combination of higher projected average consumption per customer and higher projected retail prices (in c/kWh).

Higher projected average consumption and retail prices are the result of higher projected demand from electrification, which increases the projected cost to the residential customer (primarily via higher wholesale costs). A similar trend is projected for LV and HV commercial bills, but to a lesser extent as a result of differences in average consumption being less pronounced for these customer types.

1.6 Sensitivity analysis

We have selected three key parameters for sensitivity analysis: battery deployment; EV market penetration; and RAB investment requirements. These parameters were selected on the basis that they may significantly impact outcomes, constitute areas of greatest uncertainty and/or are amenable/influenced by policy/regulatory intervention.

Batteries: To test the sensitivity in relation to battery deployment, we have increased community battery storage capacity, that is, medium sized batteries located on the distribution network[5], so that peak demand in 2045 is reduced by 25 MW in Scenario 1, 40 MW in Scenario 2 and 40 MW in Scenario 3. Community battery storage is assumed to ramp up over the projection period.

The analysis shows that the deployment of additional batteries will both lower peak demand and reduce retail bills. The bill reduction is conservative, given it is assumed that the batteries are distributed evenly across the network. Optimising the location and operation of the batteries could result in greater savings due to deferred network investment.

EVs: To test the sensitivity in relation to EV market penetration, we have modelled EV energy requirements for a mid-point between the base case and Deloitte's 'optimistic' EV uptake projections. This translates to a decrease in total ACT grid energy requirements and 50POE peak demand of around six per cent and one per cent, respectively.

The analysis suggests that EV penetration rates are a policy lever the Government can draw on with the knowledge that it will have minimal impact on retail bills and only modestly impact ACT grid energy requirements. However, in terms of overall CO_2 emissions reductions from liquid fuels the impact will be significant.

RAB: A conservative approach to setting RAB requirements is adopted in the modelling (given unknown factors that may impact final expenditure needs and timing). Alternative optimistic RAB trajectories have been developed for the base case and each scenario, which result in significantly lower upgrade costs/expenditure. Projected reductions in RAB fall by 28 to 34 per cent (depending on scenario). These lower RAB investments translate to a reduction in retail bills ranging from 10 to 20 per cent, depending on scenario and customer class.

The analysis shows that RAB requirement will have a material impact on retail bills under all scenarios from around 2030 onwards. While there is considerable uncertainty as to final RAB requirements, it is expected that retail bill outcomes would fall between what are essentially the upper and lower bounds of the conservative and optimistic RAB cases.

[5] Community batteries are assumed to range in size between 100 kW and 4 MW and are generally located on the LV system, in suburban settings.

1.7 Gas network 'tipping point'

A significant decline in gas consumption is projected under the base case and all scenarios (with the network closing in 2035 in Scenario 3). This brings into question the ongoing viability of the Evoenergy network as gas consumers increasingly convert to electricity. To analyse where the 'tipping point' may occur two methodologies were considered:

- estimate consumer savings from switching to electricity and determine at what point it is highly unlikely that gas consumers would continue to use gas

- estimate when the network ceases to be economically viable from the point of view of distributor's revenue projections, and projections on costs, rates of return etc.

ACIL Allen has chosen the first method for this analysis and builds off work recently completed examining household switching (gas to electricity) in the ACT. Moreover, ACIL Allen is not privy to the detailed Evoenergy financial data (asset valuations, investment strategy, financing models etc) that would be required to undertake the analysis from the point of view of the distributor.

The results of this analysis show that many households already have an incentive to electrify, and over time consumer savings increase significantly if gas users switch to electricity. Eventually there becomes a point where it is difficult to envisage that gas consumers will not convert to electricity, unless physical (or legal) constraints prevent conversion. The analysis considers the increase in projected retail gas bills under the base case and the three scenarios and infers whether disconnections might happen more quickly than projected.

The work focuses on the time at which this point could occur in the future. Once prices reach a point where the consumer savings significantly favour switching from gas to electricity, a tipping point will occur. At this point disconnections are likely to accelerate rapidly resulting in pressures on Evoenergy's revenue base. Increasing prices (if allowed by the regulator) to support the revenue base will exacerbate the problem leading to spiralling breakdown of the gas system integrity.

The analysis presupposes that a decision to convert is purely on an economic rational basis. However, there will be a range of other personal considerations that come into play - preference for gas cooktops over electric, capital and installation cost and capacity to finance the conversion, age and residual life/value of existing appliances, building fabric and structural constraints and long-term renovation plans etc. While there are already economic signals pointing to the advantages of conversion, the fact this is not happening to a greater extent suggests there are large frictions which are difficult to observe and quantify directly.

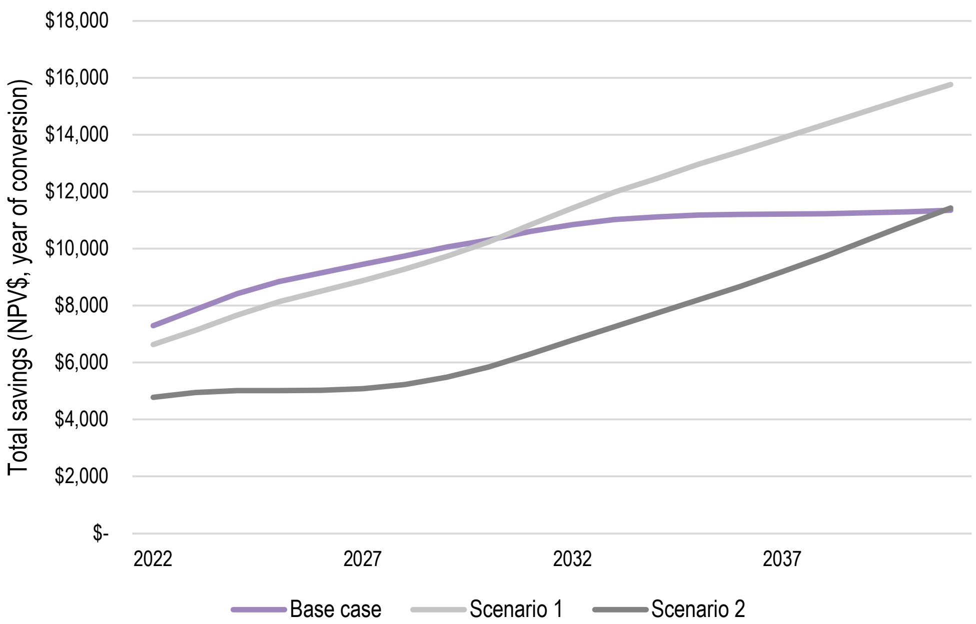
We have adopted a methodology that allows an understanding of the relative costs to ACT householders in choosing between electricity and gas (household energy choice modelling). The approach examines the cost involved in the choice of electric appliances (to replace gas appliances), including the upfront cost of buying and installing the relevant appliance and the cost of any modifications that might be required to the home itself.

To ensure a focus on the difference between the cost of using gas and the cost of using electricity, the analysis rests on a counterfactual case, in which the household in question is assumed to continue using gas, and a policy case, in which the household in question is assumed to switch from gas to electricity. The results show the estimated savings households obtain from switching to electricity from converting to electric water heating, cooking and space heating, accounting for connection/disconnection costs and the cost of appliances and installation.

The modelling outcomes for the different scenarios are represented in Figure 31. The figure shows that as gas prices increase for the base case and Scenarios 1 and 2, the potential cost savings from converting in any particular year increase out to 2041. (Scenario 3 is not presented, given that the retail price analysis for the scenario clearly indicates that the viability of the network is challenged from around 2030.)

For example, the average residential user's total savings from converting to electricity in 2025 in the base case is around $9,000 - that is, the household is facing a $9,000 decision in that year (to be realised over the following 15 years) if they have not already electrified. However, in Scenario 2, the saving is less at around $5,000. This is due to electricity prices in Scenario 2 increasing at a faster rate, as well as being higher over the entire modelled period.

Figure 31 Residential consumer saving from switching to electricity, total savings (NPV$)



Source: ACIL Allen

The analysis clearly shows potential cost savings only get higher over time. Even in 2022, there is an economic case to switch from gas to electricity. The question is then at what point does it become self-evident that that gas consumers would be very unlikely to continue to use gas (unless 'locked in' by other factors). The five-year regulatory cycles for the Evoenergy network are the logical timeframes in which to consider these outcomes. Based on the analysis it is possible to make inferences as to the period Evoenergy could face increasing disconnection rates and inadequate revenues to support the continued operation of the network.

By the early-mid 2030s the potential cost savings are much higher across - in annualised terms, gas consumers would be hundreds of dollars worse off each year (less so under Scenario 2). This is largely on the back of retail prices escalating by more than 30 per cent (compared to 2022 levels). By the early to mid-2030s, it is likely that Evoenergy will face pressures to pass on higher fixed connection costs (particularly undern Scenario 1) and variable charges in the order to recoup costs. At this point, remaining gas consumers are likely to find themselves significantly worse off if they stay connected, and accordingly they can be expected to convert to electricity as soon as possible.

Based on the analysis, it is likely that a significant number of additional disconnections would be likely by the beginning of the 2037-41 regulatory cycle (possibly earlier in Scenario 1 – during the 2031-36 cycle). The case for switching under Scenario 2 is less clear. The potential cost savings from switching for the average household are smaller, albeit still positive. The tipping point is likely to come later, potentially towards the end of the 2037-41 regulatory cycle.

Scenario 3 was not included in the analysis, given the gas price projections paint a very clear picture. In this scenario with such drastic reductions in connections from as soon as 2027, Evoenergy will be under significant pressure to pass on much higher costs to cover its operational costs. Large write-downs of the network would be likely to enable continuing supply gas to a rapidly declining customer base at affordable prices. If not, it is likely the distribution network could be unviable as early as the late 2020s and the supply of much smaller volume of customers in the years post 2030 would be better serviced by tank gas.

Cost savings under all scenarios are only set to rise and become stronger. By the 2030s, and particularly by the mid-2030s, cost savings are substantial and it is likely that disconnections will start increasing at a much higher rate than is projected. Therefore, the ACT distribution network and its assets could be unviable earlier than 2040, particularly in the case of extreme cuts in gas consumption such as under Scenario 3. It is inevitable that the tipping point will occur (including in the base case), given current policy settings. In all likelihood it will occur faster than anticipated and will be driven by a self-reinforcing cycle of disconnections, rising gas prices, and regulatory constraints. However, some households will be disadvantaged and unable to respond to the economic signals to switch. The Government and Evoenergy will need to look to proactively manage the move away from gas to ensure an orderly and socially equitable transition.

1.8 Economic impact - costs and benefits

The transition of the ACT energy system under the alternative decarbonisation scenarios will come with a range of costs and benefits compared to the base case. There will be additional expenses related to increasing renewable electricity usage, but these will be offset by reductions in gas, petrol and diesel usage. In addition, there will be extra reduction in GHG emissions under the alternative decarbonisation scenarios. These are shown in Table 1 and at Figure 32.

Table 1 Economic outcomes by scenario, relative to the base case

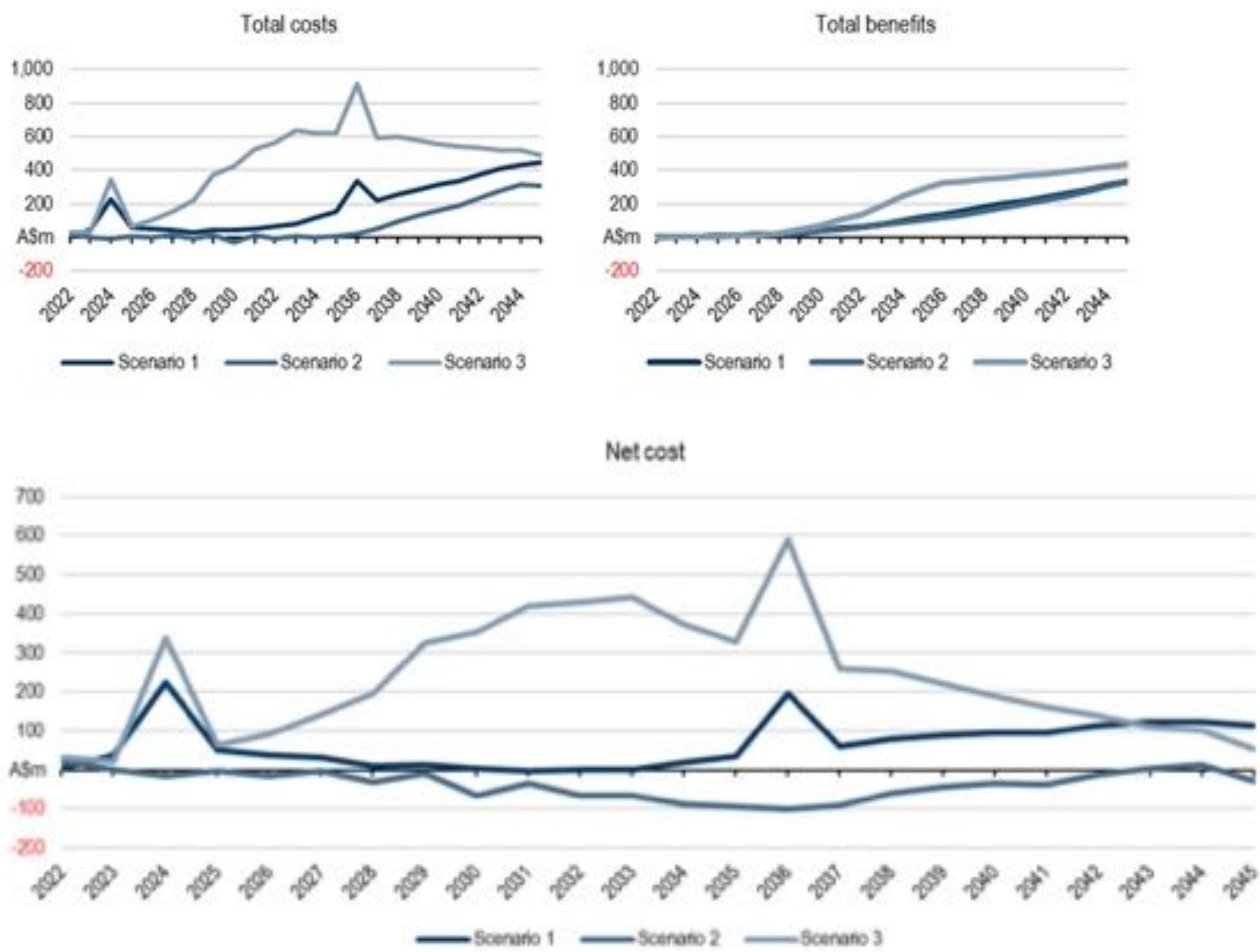
	Scenario 1	Scenario 2	Scenario 3
Costs	+$1,606 million	+$497 million	+$4,380 million
Benefits	+$906 million	+$842 million	+$1,601 million
Net cost and GHG emissions	+$700 million cumulative reduction of 2.3 Mt CO_2-e	-$344 million cumulative reduction of 2.1 Mt CO_2-e	+$2,779 million cumulative reduction of 5.0 Mt CO_2-e
Implied emissions abatement cost	+$301/t CO_2-e	-$166/t CO_2-e	+$554/t CO_2-e

Note: costs may be understated given energy efficiency gains not included.
Source: ACIL Allen

Scenario 3 is expected to have the largest additional costs relative to the base case, driven by significant upgrades to the electricity network, as well as the largest additional benefits driven by the largest savings in gas purchases. While Scenario 3 is projected to have the largest reduction in GHG emissions compared to the base case (driven primarily by the rapidity with which gas is removed from the ACT energy system), it is also the scenario with the highest additional net costs (driven by the large capital expenses needed to boost electricity supply earlier in the projection period and to ensure security of supply).

The net cost of Scenario 2 relative to the base case is negative, meaning that the overall reduction of gas and other fuel costs (and human health benefits) are greater than the increased costs associated with the additional electricity -related expenses. The implied a GHG emission abatement cost foe Scenario 2 meaning it delivers a superior value for money outcome in comparison to the base case.

Figure 32 Total costs, benefits and net cost of each scenario, relative to the base case



Note: The cost 'spike' in 2024 relates to the additional large and community battery installation costs (the 2036 'spike' corresponds to the refresh of these batteries)

Source: ACIL Allen

1.8.1 Macroeconomic impacts

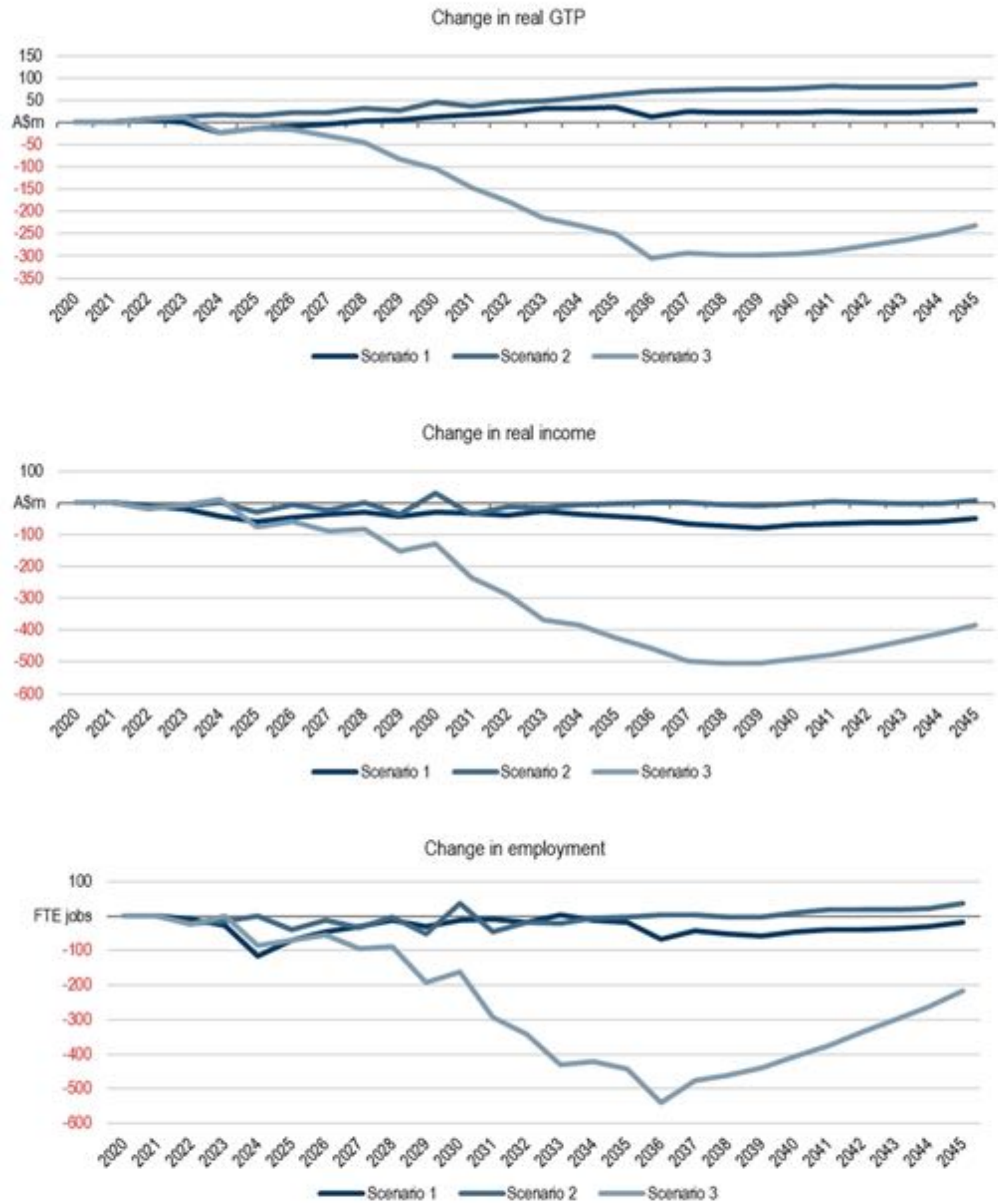
Figure 33 shows the annual macroeconomic and employment impacts of each scenario, relative to the base case.

From a macroeconomic perspective Scenario 2 clearly delivers the best outcome in terms of GTP, real income and employment, even though it only delivers net positive outcomes in relation to GTP. It is also the most economically stable scenario with the smallest year on year fluctuations.

The change in real income is considered the best macroeconomic indicator of the change in the welfare of ACT residents over time – the cumulative change in the real income of ACT residents, relative to the base case, (using NPV7) is:

- -$474 million under Scenario 1
- -$102 million under Scenario 2
- -$2,397 million under Scenario 3.

Figure 33 Macroeconomic impacts of each scenario, relative to the base case



Source: ACIL Allen

1.8.2 Investment sensitivity

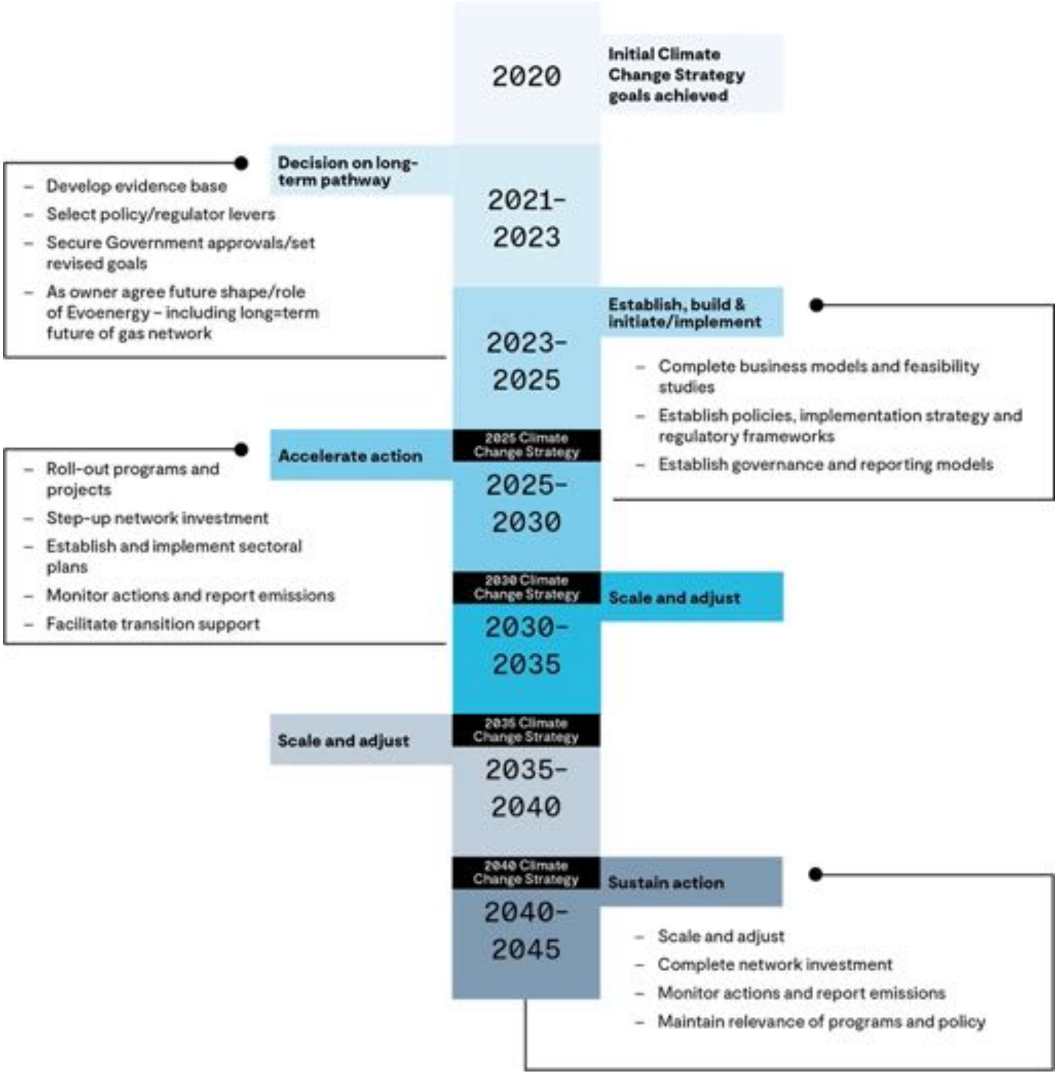
The power modelling undertaken for this Report, has been performed to identify and quantify future levels of investment into the Evoenergy electricity network to aid in identifying the cost that would be passed onto energy consumers to maintain the network to current levels of safety, security and reliability. When considering the outcome on the RAB based on the investments and other economic factors - the study approach is premised on a conservative, worst-case scenario (largest impact on customer tariffs). The main factors influencing the difference between the worst-case and most optimistic scenario are primarily:

- economic factors such as CPI, depreciation and asset retirement
- growth factors – how much demand growth is related to new connections vs increased consumption per connection
- project delivery factors - the breakdown of materials, labour, land purchases etc. that determine how much of the cost of each investment contribute to the RAB
- customer project factors – for customer projects there is a range of how much the assets added by the project contribute to the RAB, especially when considering works could be performed by option 2 parties.

1.9 Implementation timeline

Achieving net zero transformation will require early action/'wins' and a sustained focus on implementing policy and supporting investment programs to reduce GHG emissions and support a resilient and sustainable ACT economy and community. Detailed timelines with supporting GHG emissions targets will be required following down-selection of the net zero pathway selected by the ACT Government. Figure 34 highlights the indicative phases of planning and delivery required to meet the 2045 timeline.

Figure 34 Indicative Phase for Net Zero transformation



2. Project scope

2.1 Project purpose

The Environment Planning and Sustainable Development Directorate (EPSDD) requires a comprehensive understanding of the impact that the Territory's climate change policies and objectives may have on the ACT electricity network. It requires strategic scenario advice to consider the modelling outcomes and provide options and scenario analysis on how the Territory may achieve its climate change reduction targets by 2045, whilst balancing consumer and electricity network impacts.

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:

Stage 1 **Base case Report** submitted to Government, December 2021, represents the results of economic and technical modelling of the agreed base case.

Stage 2 **Strategic Report** –this document - sets out the results of economic and technical modelling of three (3) realistic policy scenarios.

The objective of the modelling (in both Report 1 and Report 2) is to provide the ACT Government with 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.

This **Strategic Report** provides strategic advice on the practicality of the ACT Government achieving its policy objectives through the scenario pathways, whilst maintaining 100 per cent renewable electricity and balancing network capabilities, energy security, quality of supply and costs to consumers.

2.2 Project approach

This **Strategic Report** builds on the outcomes to date (base case modelling set out in the Stage 1 Report) and incorporates the economic modelling of electricity and gas network impacts, including upgrades, offsets, and total costs to stakeholders against the three (3) alternate scenarios.

2.2.1 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. Chapter 4 sets out the detailed methodology used to model the three (3) scenarios. The detailed modelling of the electricity network against three (3) scenarios with consideration of current and expected market trends, and parameters drawn from existing ACT Government policy settings/announcements. Modelling focused on:

- Electricity network – constraints and opportunities in terms of capacity, demand, 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
- Economic modelling – modelling of electricity network impacts, including upgrades, offsets, and total costs to stakeholders.

2.2.2 Assumptions

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

A summary of modelling assumption is provided at Appendix A.

2.2.3 Policy considerations

There are an array of ACT Government policy commitments and strategies which have been considered in the base case's parameters and the alternate scenarios modelled.

The degree of relevance and impact varies considerably. Appendix B details the key policies that have been considered in the development of the three scenarios, the modelling of the base case and inclusion in assumptions.

2.2.4 Consultation

For the purposes of this study, ACT Government stakeholders were consulted to inform the development of the base case and the three (3) scenario options. A summary of stakeholder consultation is provided at Appendix E. Consultation focused on the considerations of:

- the outlook for GHG 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.

2.3 Project 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 2.1 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.

3. Project Context

The Australian Government has committed the nation to a net zero future – but this is dependent on robust strategies implemented at the state and territory government level which establish the necessary foundation to make real cuts to greenhouse gas emissions supported by policies and program that support a decarbonised economy.

The ACT Government has commitment to net zero emissions reduction by 2045. Achieving a net zero future will unquestionably require a significant transformation of the economy. For this to occur, current energy systems, process, infrastructure, and transportation decisions across every industry sector will need to be challenged, reviewed and adapted.

Transformation will be a complex journey and cannot be achieved by government alone – it will require technologies, policies, and markets working together.

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. The strategic policy context that will influence the ACT Government's decarbonising activities is addressed along with the critical planning considerations associated with the energy sector.

3.1 Planning for a net zero future

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 that can impact net zero progress:

- 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, ZEVs, 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 technology development, 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 will determine 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 gases (biogas and hydrogen) to play a role in the future energy mix, even though:
  - most development in this sector is based on industrial uses and export
  - the technical challenges, cost and current ACT industrial and commercial profile suggests (green) gas may have limited commercial viability in the ACT
- 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.

3.2 Strategic considerations

A successful transition towards a net zero emissions economy requires interface with and consideration of the multifaceted policy context in which decarbonisation is required to operate within.

3.2.1 International policy context

The 2015 Paris Agreement agreed to hold the increase in the global average temperature to well below 2°C above pre-industrial levels, and to pursue efforts to limit it to 1.5°C.

The Paris Agreement aims to 'strengthen the global response to the threat of climate change', and its stated goal, in Article 2 of the Agreement, is to limit the increase in the global average temperature to 'well below 2 degree C' above pre industrial levels.

The projected global emission targets are illustrated at Figure 35.

Importantly, the Paris Agreement established the concept of carbon neutrality as a framework for guiding climate action, assessment frameworks, governance processes, and transformational policies focussed on net zero futures.

The Australian Government announced its ratification of the Paris Agreement on 10 November 2016 and established early intended 'Nationally Determined Contributions' (NDCs) through to 2030 which set out an economy-wide target to reduce greenhouse gas emissions by 26 to 28 per cent below 2005 levels by 2030.[6]

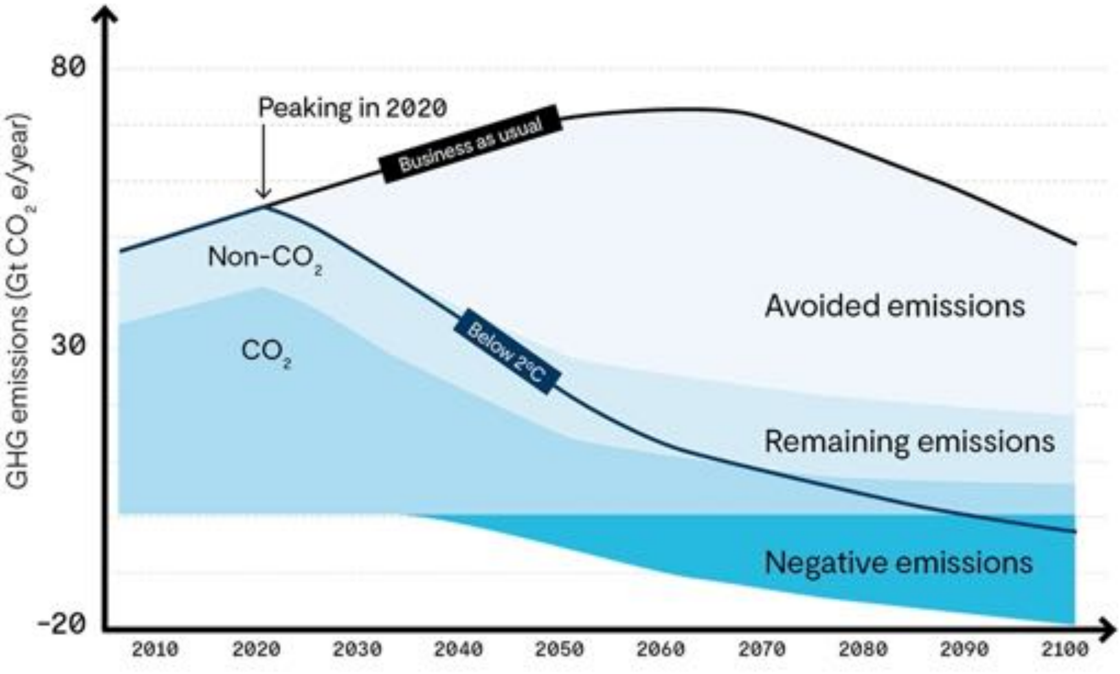
Following the 26th Conference of the Parties (COP26) in late 2021, these NDCs have subsequently been updated to reflect an Australian Government commitment to:

- an (interim goal) reduce emissions by 26 – 28 per cent below 2005 levels by 2030
- a (long-term goal) net zero emissions by 2050
- low emissions technology stretch goals.

The Paris Agreement was made under the United Nations Framework Convention on Climate Change (Climate Change Convention, also referred to as the UNFCCC).

[6] Nationally determined contributions (NDCs) are at the heart of the Paris Agreement. They embody efforts by each country to reduce national emissions and adapt to the impacts of climate change. The Paris Agreement requires each Party to prepare, communicate and maintain successive NDCs that it intends to achieve. Parties shall pursue domestic mitigation measures, with the aim of achieving the objectives of such contributions.

Figure 35 Projected global emission reduction targets



Source: World Resources Institute ***www.wri.org/carbonremoval***

3.2.2 National policy context: decarbonising the Australian economy

The Australian Government's commitment to its 2030 emissions reduction target with net zero emissions by 2050, is underpinned by a Long-Term Emissions Reduction Plan (the Plan) and Technology Investment Roadmap (the Roadmap). The Government has identified that technology will be the key driver for projected reductions in emissions, requiring new measures to accelerate the development and deployment of low emissions technologies.

Achieving this transformation will require early action/'wins' and a sustained focus on implementing policy and supporting investment programs to reduce emissions. The Roadmap sets a process to develop and deploy low emissions technologies to support national emission reduction targets. Both the Plan and the Roadmap are supported through a number of strategies and policies with implementation across numerous government departments and agencies that are focussed on:

- a technology led approach to emissions reduction
- international low emissions technology partnerships
- emission reduction incentives
- regulating emissions
- reporting on emissions.

On the basis of progress to date, government modelling indicates that Australia is on track to achieve its interim (2030) target through a reduction in (national) emissions by up to 35 per cent (below 2005 levels) (Figure 36).

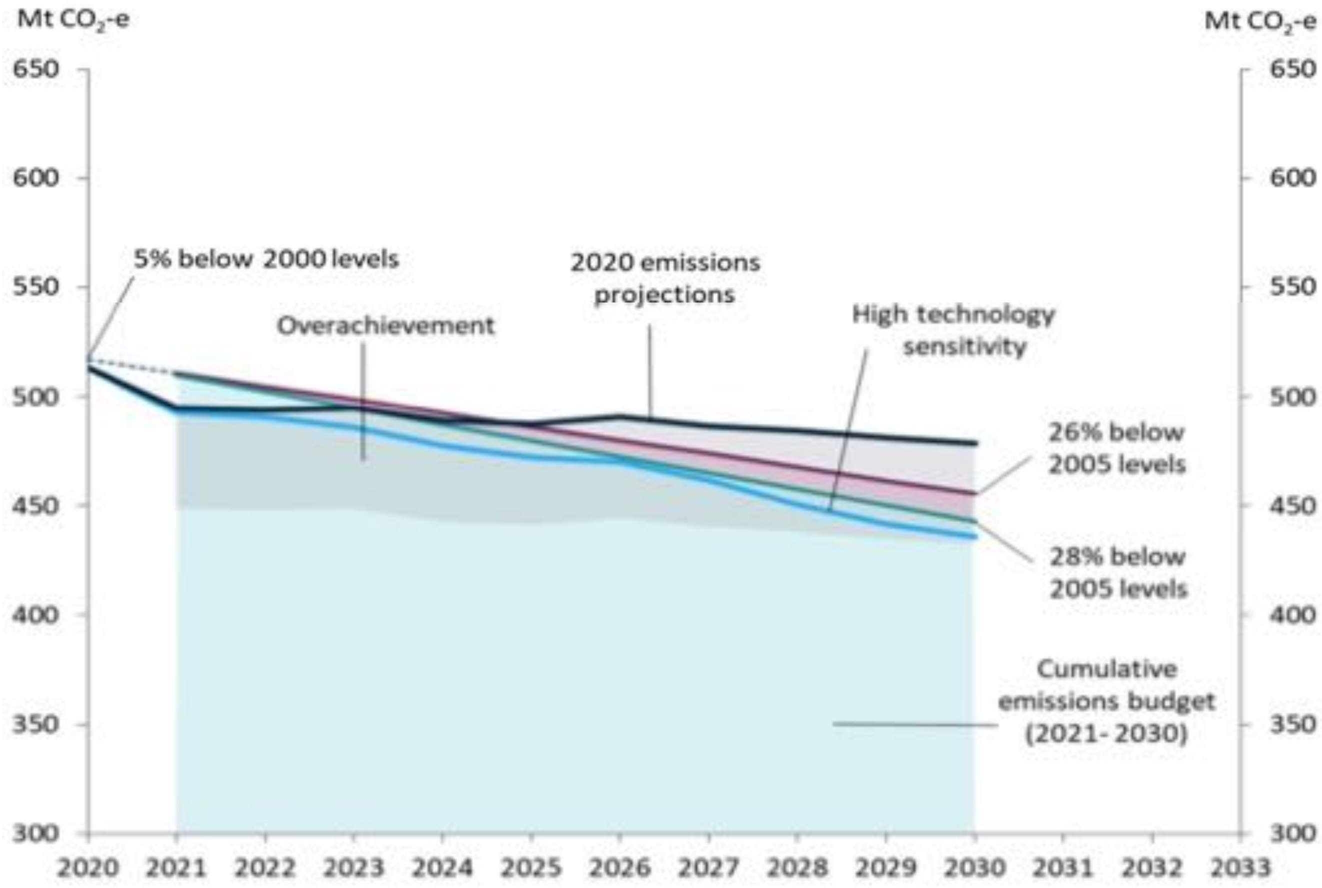
To achieve Australia's 2030 target, there will be a heavy reliance on:

- the Technology Investment Roadmap, and associated measures to accelerate the development and deployment of low emissions technologies

- a further reduction in projected emissions from the electricity sector due to continued strong renewables uptake (particularly small and mid-scale solar) by households and businesses.

Achievement of the 2030 emissions target and the later 2050 net zero emission target will also be dependent on action at the state and local level to reduce national emissions.

Figure 36 Australia's emission reduction task to 2030



Source: Australia's Emissions Projections 2020, DISER

3.3 ACT's Net Zero Emissions commitment

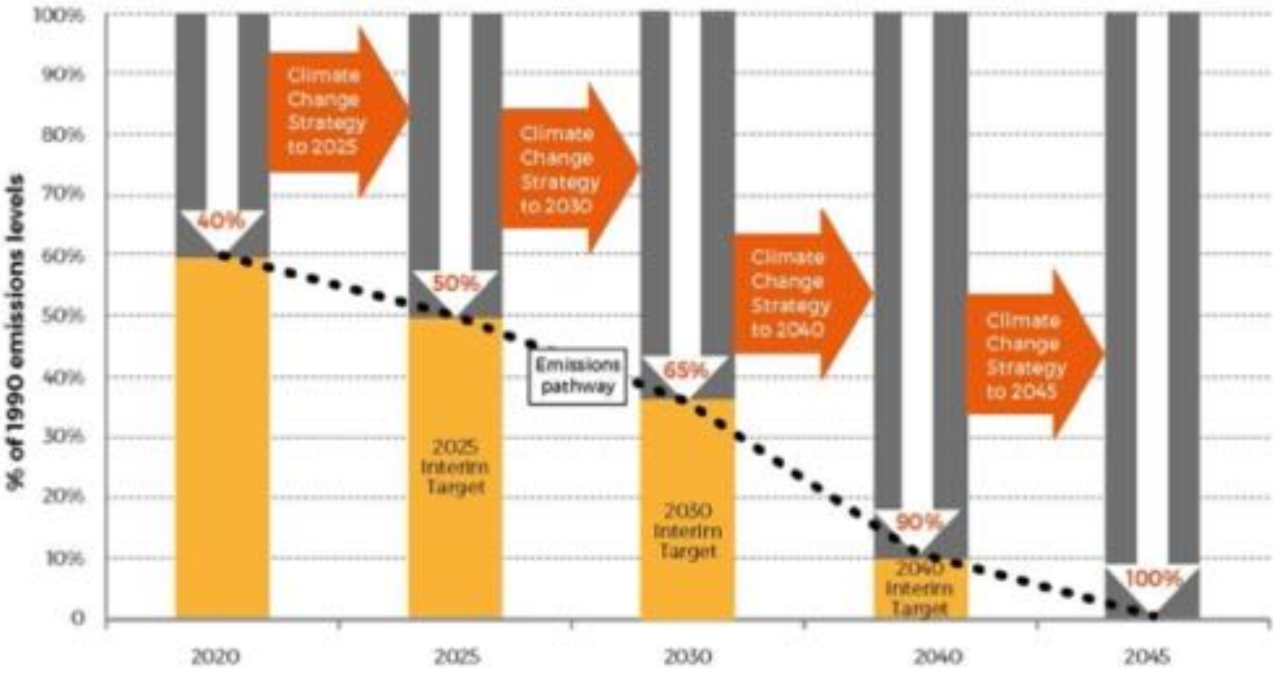
Action on climate change through emissions reduction brings the opportunity for wider benefits for our society individual wellbeing, economy, and environment from improving public health to protecting biodiversity. The ACT Government has committed to a net zero emissions economy recognising that this will be a challenging and complex transition requiring an adaptive and innovative approach to implementing emission reduction strategies.

3.3.1 ACT Climate Change Strategy (2019-2025)

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 has set world-leading emission reduction targets that are legislated under the Climate Change and Greenhouse Gas Reduction Act 2010. The Government's Climate Change Strategy (2019-25) outlines the actions and key priorities 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 (Figure 37).

The development of the Climate Change Strategy was informed by extensive community and business consultation. Underpinning the strategy is a consideration of factors such as reducing energy costs, managing impacts on workers and businesses, and providing tailored information and support for low-income households.

Figure 37 ACT's emission reduction targets to 2045



Source: ACT Climate Change Strategy 2019-2025

Achievement of the targets set out in Figure 37 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 that as an energy source, it is emissions intensive, and can easily be replaced with a zero emissions alternative.

The Government has aligned 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 ACT Government reassess the emission targets and commitments set out in the Climate Change Strategy on a 5-yearly basis to ensure currency and relevancy of action.

A summary of the ACT Climate Change Strategy is provided at Figure 38.

Figure 38 ACT's Climate Change Strategy

ACT's climate change strategy

Need for Action

The ACT Government is committed to reduce emissions and increase our resilience to unavoidable climate change impacts with a focus on achieving our goal of net zero emissions by 2045. Achieving net zero emissions will require changes across all sectors of the economy over coming decades. It will also require substantial changes in the way we plan and build our city, how we travel, the appliances and products we choose.

Vision

Net zero

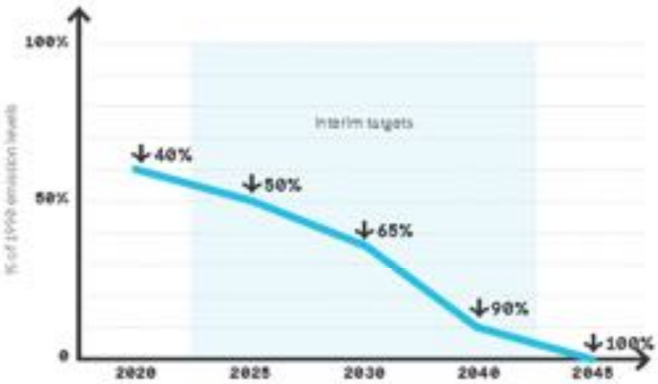
The ACT will be a leading net zero emissions territory that demonstrates that a healthier, smarter future is possible.

100%

renewable electricity will be used to power the ACT 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.

Commitment

The ACT has set world-leading emission reduction targets that are legislated under the Climate Change and Greenhouse Gas Reduction Act 2010.



Priorities

- Community leadership and just transition
- ACT Government leadership
- Transport
- Waste Avoidance and management
- Energy buildings and urban development
- Land use and biodiversity

Principles

- Ambitious
- Collaborative
- Efficient
- Equitable
- Innovative
- Integrated
- Urgent

Achievements so far

The ACT is recognised nationally and internationally for our successful transition to 100% renewable electricity and our world-leading emission reduction targets. The Government will build on these achievements and continue to take the lead in rapidly and efficiently reducing emissions and preparing for climate change impacts. The Government continues to collaborate with the community and businesses to find innovative solutions for a better future including through:

Support for the uptake of zero emission vehicles

Improved energy efficiency and sustainability outcomes for households, businesses and schools

Reduced emissions from Government operations

Increased resilience to climate change

3.3.1.1 Priorities for achieving net zero emissions

The ACT Climate Change Strategy 2019-25 also sets out the future priorities for Government post 2025 to reach net zero emissions by 2045 as shown in Table 2.

Table 2 Key priorities to 2025 and post 2025

Priorities	To 2025 – Key Priorities	From 2025 – Future Priorities
Community leadership	Support community-driven solutions to climate change including grants and trialling new models for collaboration.	Continue to encourage community and business leadership and action.
	Encourage preparedness and adaptation action by households and businesses.	
	Review progress annually and work with experts, stakeholders and the community to identify innovative ideas for implementation.	
Just transition	Provide support for low-income households and vulnerable sectors of the community to enable participation in responding to climate change.	Continue tailored programs and support for renters and low-income households to reduce emissions and adapt to climate change. Continue to work with industry to pursue opportunities for training, economic diversification and attracting low carbon investment and jobs.
	Identify affected sectors and support re-training of workers where needed.	
Transport	Support higher uptake of public transport by continuing to improve services to meet community travel needs.	Continue to electrify public and private transport and support active travel.
	Trial new ways of using roads that most efficiently move people and goods and better support sustainable transport modes.	
	Encourage active travel by continuing to improve cycle paths and walkability.	
	Encourage the uptake of zero emissions vehicles and explore the need for further incentives.	
	Plan for a compact and efficient city to improve access to public transport and active travel options, reduce travel distances and reliance on private car use.	
Energy, buildings and urban development	Implement Canberra’s Living Infrastructure Plan to reduce urban heat and improve liveability.	Continue to improve building standards to deliver efficient new buildings that are designed for the current and future climate. Continue to increase tree canopy cover and maintain a healthy urban forest.
	Encourage a shift from gas to electricity by removing the mandated requirement for gas connection in new suburbs, supporting gas to electric appliance upgrades and encouraging new-builds to be all-electric.	
	Maintain 100% renewable electricity through efficiency and additional procurement of renewable electricity if required.	
	Improve energy performance and climate change resilience requirements for new buildings and introduce minimum energy performance requirements for rental dwellings.	
	Improve liveability and adapt to the impacts of climate change by implementing Canberra’s Living Infrastructure Plan and continuing to explore approaches to reducing urban heat.	
	Plan for efficient and sustainable urban land use to reduce emissions and maintain and enhance living infrastructure and biodiversity.	
ACT Government leadership	Transition to a zero emissions Government passenger vehicle fleet and a zero-emissions bus fleet where fit for purpose.	Continue to collaborate and find new and innovative solutions.
	Reduce emissions from Government operations by over 33% by 2025 (from 2020 levels).	

Priorities	To 2025 – Key Priorities	From 2025 – Future Priorities
	Shift to high efficiency, all-electric and climate-wise Government buildings and facilities.	
	Investigate applying a social cost of carbon and climate change adaptation considerations in procurement and capital works decisions.	
	Invest the social cost of emissions from Government operations from 2020 onwards in measures to further reduce emissions rather than purchasing carbon offsets.	
	Monitor climate change projections and ensure infrastructure and services are resilient to climate change impacts.	
Waste avoidance and management	Divert organic waste from landfill by continuing to roll out garden waste collection to all suburbs and expanding to include household food waste.	Continue to encourage reduced waste generation, divert organic waste from landfill and reduce emissions from waste treatment.
	Investigate options to divert additional organic waste from landfill by requiring key sectors to have a separate organic waste collection.	
	Identify opportunities to reduce emissions from organic waste treatment and potential sites for processing.	
Land use and biodiversity	Identify and enable opportunities for carbon sequestration in tress and soils and for adaptation innovation.	Continue to increase tree canopy cover and maintain a healthy urban forest. Foster resilient agricultural and plantation forestry industries.
	Encourage sustainable farming practices which are fit for the current and future climate.	
	Identify the risks from climate change to species, ecological communities and ecosystems and take action to improve resilience and adaptation.	
Source: ACT Climate Change Strategy 2019-2025		

3.3.2 ACT progress 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 3.

Building on 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 all sectors of the economy.

Achievement against these targets have contribution to Australia's Nationally Determined Contributions (NDCs) under the Paris Agreement. 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 3 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)				

3.3.3 Energy sector transition

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 secure new renewable electricity resources 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 many sectors that use energy.

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 biogas and/or hydrogen into the system (in accordance with existing policy commitments). However, the introduction of 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.

4. Project methodology

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 biogas), or a combination of both, only limited modelling of gas demand was undertaken to inform the electricity network analysis.

4.1 Modelling approach: base case and policy scenarios

To develop the base case and policy scenarios we drew on various energy reports to develop a consensus view on the energy projections to 2045 and to inform the development of plausible, defensible scenarios for the future shape of the ACT energy sector. These reports include Australian Energy Market Operator (AEMO) 2021 Input, Assumptions and Scenarios, National Electricity Market (NEM) Electricity Statement of Opportunities (ESOO), Gas Statement of Opportunities (GSOO) and Integrated System Plan (ISP); wholesale electricity modelling undertaken by the Australian Energy Market Commission (AEMC); modelling undertaken for the Energy Security Board (ESB) etc.

The base case (and scenarios) incorporate recent Commonwealth (or COAG) energy market policy announcements and reforms (e.g. a gas-fired recovery; gas supply strategy; gas market reform; reliability and security measures) to the extent that these actions directly impact the market model outcomes and are incorporated into the parameters accessed through NEM/AEMO data. Core assumptions and data inputs underpinning the electricity market modelling and the gas market projections are mapped at Figure 39 and discussed in detail within the following Section.

4.1.1 Gas demand projections

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

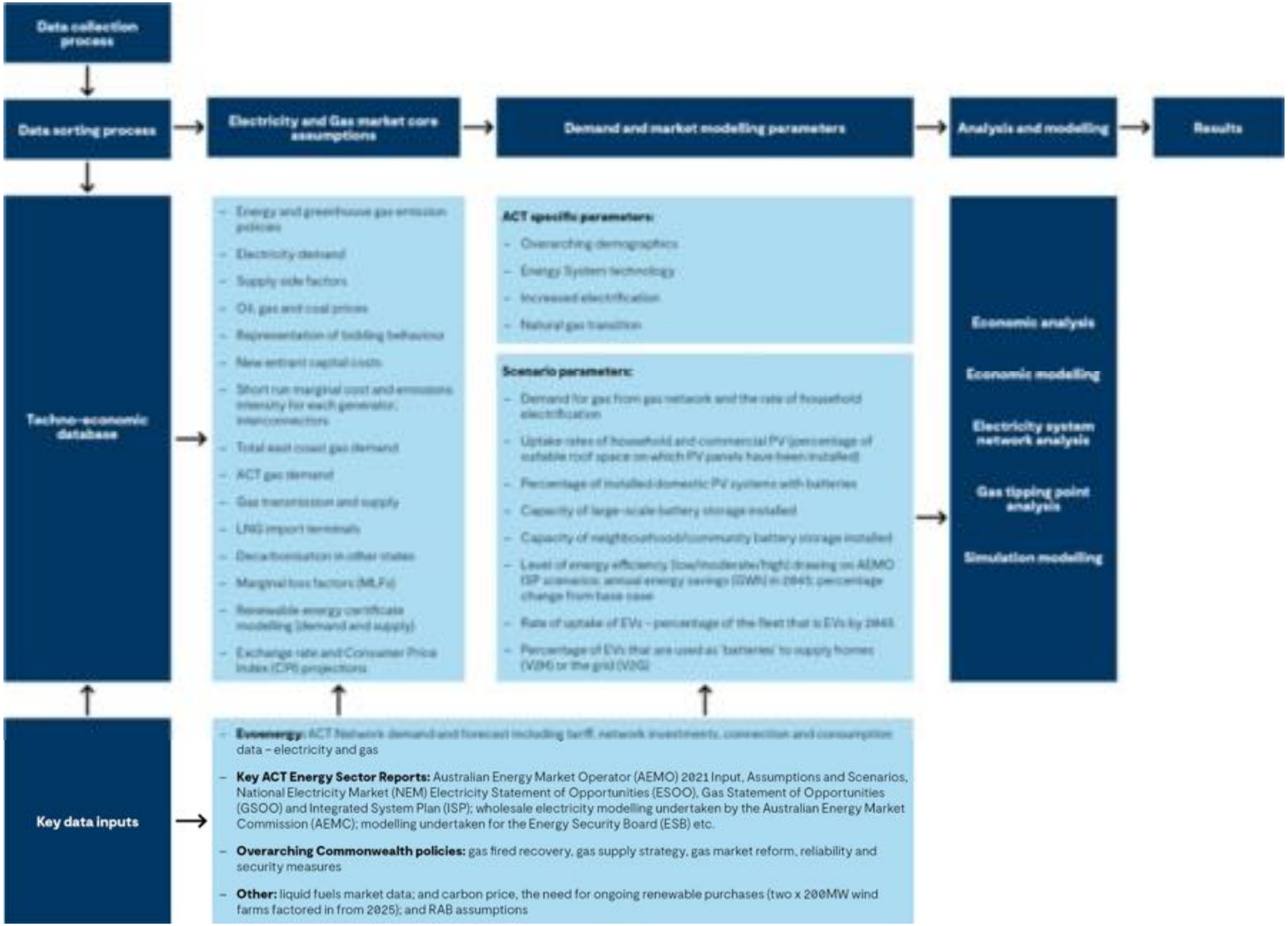
- developing a simple projection for ACT gas consumption through to 2045 (natural gas consumption is assumed to be effectively phased-out by that date in line with the Government's policy) – this projection is based on historical trends in gas demand, with the results used to inform the electricity network 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.

The gas demand projections for both the base case and scenario modelling are based on only limited modelling of the gas network, that is it does not constitute a full gas transition model, with limited 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.

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

Further detail regarding core assumptions for the electricity and gas market modelling is provided at Appendix A.

Figure 39 Core assumptions and data inputs informing electricity market modelling and gas market projections



4.1.2 ACT specific parameters

The core assumptions outlined above address whole-of-market (i.e. the NEM) issues and do not capture ACT specific considerations. Adjustments were made to the model input parameters to ensure the base case considers the ACT's pathway to the phasing out of fossil-fuel-gas by 2045, including a range of ACT Government policy commitments and strategies. 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 (some of these factors are varied under the different scenarios). These ACT factors include:

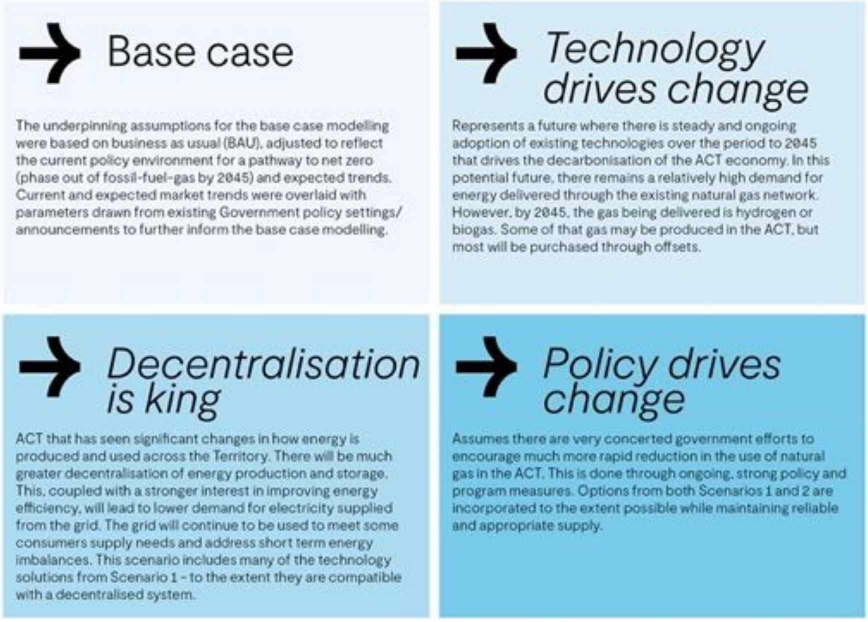
- **Overarching demographics, economic development urban developments and policy considerations**: demographic and economic development settings/projections (economic/industry composition, regional development); the objective of phasing out of fossil-fuel-gas in the ACT by 2045; the continuing policy to purchase 100 per cent renewable electricity; options to consider carbon offsets; implications of infrastructure developments; and climatic and weather projections.
- **Energy systems/technology**: electric vehicle (EV) uptake in line with 'conservative' EPSDD projections (as per the provided Deloitte analysis); technology uptake (for example, roof top photovoltaic (PV) and behind the meter battery deployment (BESS) in line with current market trends; no significant infrastructure upgrades to energy networks; no significant new technologies adopted over next 10 years unless commercial application is likely; behavioural changes consistent with current trends; 'large-scale' battery storage distributed across the ACT in place by 2025; pilot hydrogen vehicle fuelling station in operation.
- **Increased electrification:** market penetration by ZEVs in line with 'conservative' EPSDD projections (as per provided Deloitte analysis); projected growth in charging stations and electricity demand; commitments to zero emissions public transport, garbage trucks, taxi and rideshare vehicles by 2035; demand side management/energy efficiency gains and incentives follow existing trends.
- **Natural gas transition:** 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 along with gradual conversion of existing public housing stock to fully electric; no (unforeseen) step changes in gas composition (a maximum of 20 per cent hydrogen and/or biogas gas) in line with market expectations; declining contribution from natural gas to the energy mix; and industrial consumers transitioning away from natural gas (where this is possible).

4.1.3 Scenario development

Three (3) alternative scenarios are used to inform the Government's decision making as to policy and regulatory drivers to deliver the net zero emissions pathway for the ACT's energy distribution networks. The scenarios reflect plausible and realistic energy futures to which the Territory could aspire. The scenarios have been developed to concentrate 'ambition' (and the level of policy effort) on different decarbonisation options in each case.

The scenarios modelled were agreed with EPSDD. The key themes of the base case versus scenarios are summarised at Figure 40. The scenarios incorporate changes to a number of base case parameters encompassing various adoption/transition profiles including forecasts of costs, electricity demand and emissions reductions for different periods from the present to 2045.

Figure 40 *Base case versus scenario key themes*



Under all scenarios natural gas use is expected to decline relative to the base case. Parameters adjusted include:

- demand for gas from 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) - annual energy savings (GWh) in 2045, percentage change from base case – drawn from AEMO ISP scenarios[7]
- 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 respective narratives for each of the three scenarios (Scenario 1: *Technology drives change*; Scenario 2: *Decentralisation is king*; and Scenario 3: *Policy drives change*) are in the following chapters. Each scenario is modelled as a standalone option. Details of the key parameters that have been varied, including gas demand, rooftop PV and battery deployment, EV uptake and energy efficiency gains are detailed in Table 4. The scenario analysis includes 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. While green gas may be a long-term option, the work does not extend to a full transition model and does 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 capital expenditure/operational expenditure (CAPEX/OPEX) costs are not pursued.

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[7] Energy efficiency improvements draw directly on AEMO's 2019-20 ISP. While we note that an exposure draft of the updated ISP has been released, this is not drawn upon as it is yet to be settled. The base case assumes low/moderate energy savings of around 485 GWh by 2045 which is in line with the current market trajectory (which incorporates existing state-based incentives). For each of the modelled scenarios we have drawn on a different ISP scenario (moderate energy savings based on ISP 'Net Zero by 2050'; moderate/high energy savings based on ISP 'Strong Electrification'; and high energy savings based on ISP 'Step Change and Hydrogen Superpower').

Table 4 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
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

Variable	Description	Base case	*Technology drives change*	*Decentralisation is king*	*Policy drives change*
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes autonomous vehicles (Avs) – all assumed to 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					

4.1.4 Gas tipping point

The base case projects total gas consumption to decline by approximately 60 per cent. This is a marked change from the past decade where total annual consumption has been relatively stable (driven by new connections). The Government's electrification policy, which limits new gas connections, is strongly driving the projected decline in gas use. The scenarios explore the opportunity to accelerate this decline through placing further policy limitations around new connections or incentivising consumers to adopt higher levels of electrification.

There will be a 'tipping point' where the gas network becomes uneconomic to operate. Understanding this 'tipping point' is critical to determining what further intervention is necessary to drive further electrification or whether a 60 per cent decline is close to triggering commercial collapse.

Declining gas demand will directly impact Evoenergy's capacity for future investment and maintenance of the gas network. The projected decline 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 is a key consideration for the scenarios which have deeper cuts to natural gas use and the transition to electrification is accelerated.

Understanding the 'tipping point' is 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 the 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. Outcomes of the modelling and analysis of the gas network 'tipping point' are addressed in Section 9.4.

4.2 Economic analysis

The economic modelling is an extension to the technical network modelling and details the economic outcomes (including costs to upgrade network, offsets, renewable energy generation/purchase requirements, avoided and/or transferred costs) related to changes to the Territory electricity network and electricity demand as a result of the policy changes. Outcomes provide the impact of costs to stakeholders which may include, but not be limited to, the total annual cost to the electricity distributor and the Territory, and the annual retail bill impact to consumers per year.

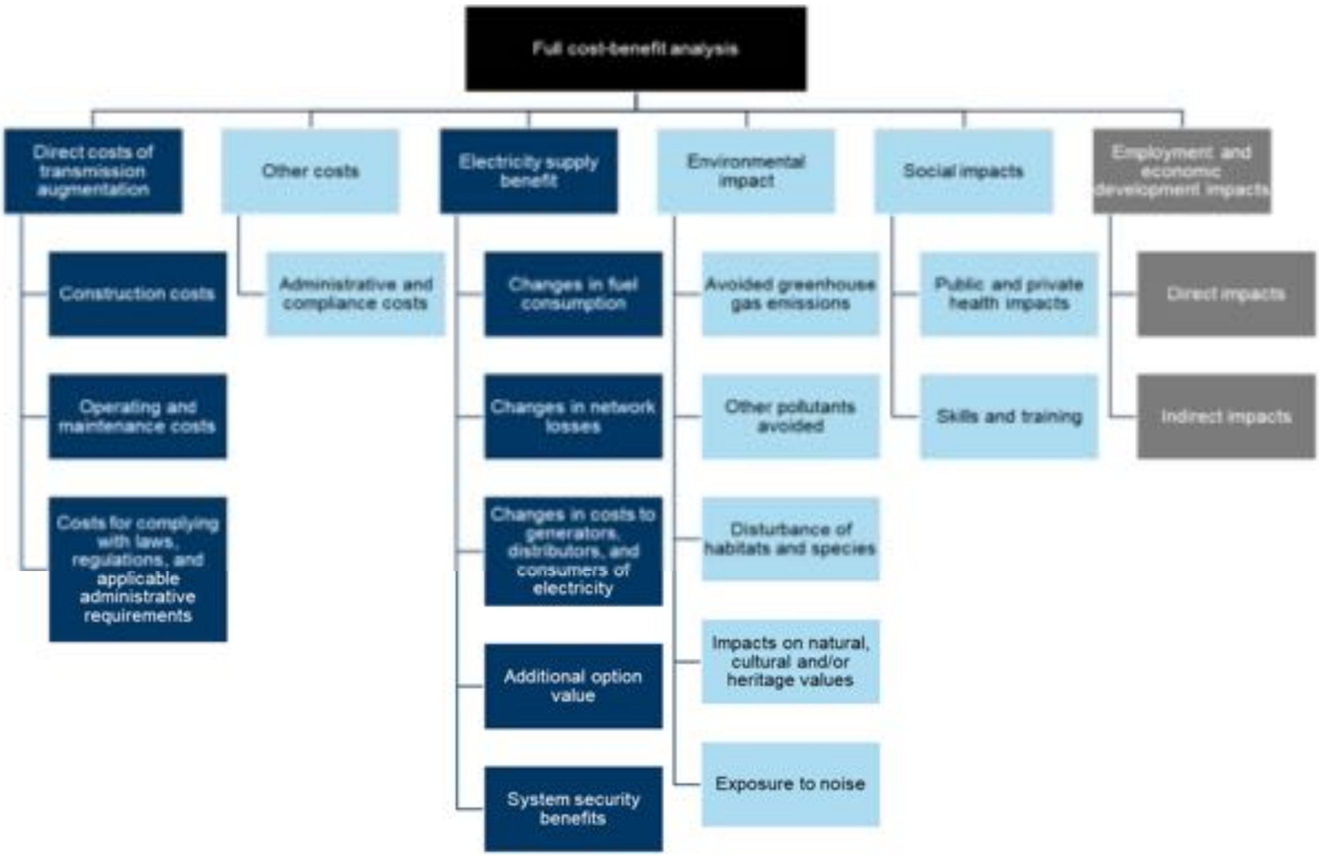
Key considerations underpinning the retail price impacts model are detailed at Appendix A.

4.2.1 CBA frameworks

A core part of the economic modelling for each scenario will be an economic cost benefit analysis (CBA). Each CBA will draw on the information developed in the other components of the analysis (such as the network capital and operating costs and other electricity market impacts) and also include estimates of the economic impacts beyond the electricity market and to the broader ACT economy. This will be underpinned by various economic estimation techniques, potentially including computable general equilibrium (CGE) modelling. Figure 41 illustrates the comprehensive cost benefit framework used by ACIL Allen for electricity network analysis. This framework is drawn from a range of sources including: the RIT-T; the Victorian Guide to Regulation; the European Union Guideline for Cost Benefit Analysis of Grid Development Projects; and the US Working Group for Investment in Reliable and Economic Electric Systems. It is important to note:

- The RIT-T framework (dark blue boxes) reflects a partial equilibrium analysis of the augmentation – that is, it only considers impacts to the electricity sector itself. Direct and indirect electricity sector costs are weighed against net electricity sector market benefits (sum of producer and consumer surplus).
- A full RIT-T is undertaken for a select number of augmentation options across a range of plausible scenarios.
- Extending beyond the partial analysis of the RIT-T, other benefit can also be assessed as shown by the light blue and grey boxes. Grey boxes are essentially broader economic benefits which are able to be quantified; light blue boxes are broader social benefits and externalities which generally cannot be quantified.

Figure 41 Full transmission project cost-benefit analysis framework



Source: ACIL Allen, Supplementing Electricity Network Investment in Western Vic, October 2018

4.2.2 Economic modelling

The network modelling components will provide impacts on:

- changes in capital and operating expenditures
- change in fuel costs
- change in network losses (changes in system reliability, and/or other changes in sector costs (predominantly capital deferral benefits)).

The implementation of policy levers and technology to decarbonise the ACT economy has the potential to generate significant technical, environmental and commercial benefits for all Canberrans, but could potentially, entail significant costs.

The net value of these benefits and costs for each scenario will be assessed through a rigorous analysis which also examines the implications for additional decarbonisation. The outcome of this analysis includes an implied cost of achieving additional decarbonisation under each scenario relative to the base case.

The employment and economic development impacts will be derived from economic modelling – specifically CGE modelling which we regard as superior to Input Output (IO) multiplier analysis. The main factors that need to be considered when analysing the macroeconomic impacts include:

- the direct and indirect contribution to the economy as a result of the activities associated with the policy scenario
- any crowding out implications as resources are potentially diverted from other productive activities to undertake the policy scenario
- any productivity effects generated as a direct result of the policy scenario – particularly any enduring productivity changes or productivity impacts on other activities not directly associated with the scenario
- any changes to the factors of production in the economy
- any implications associated with changes in terms of trade or foreign income transfers
- whether there is a dynamic element to the size of any of the above effects (for example, due to different phases of the policy scenario).

Figure 42 shows these components graphically. Some of these effects may be negligible while others may be very significant, depending on the policy scenario. The CGE model implicitly assesses each of these impacts, even where the impact is negligible.

The broader economic impacts on the ACT economy potentially arising from each scenario will be determined using ACIL Allen's CGE model, *Tasman Global*.

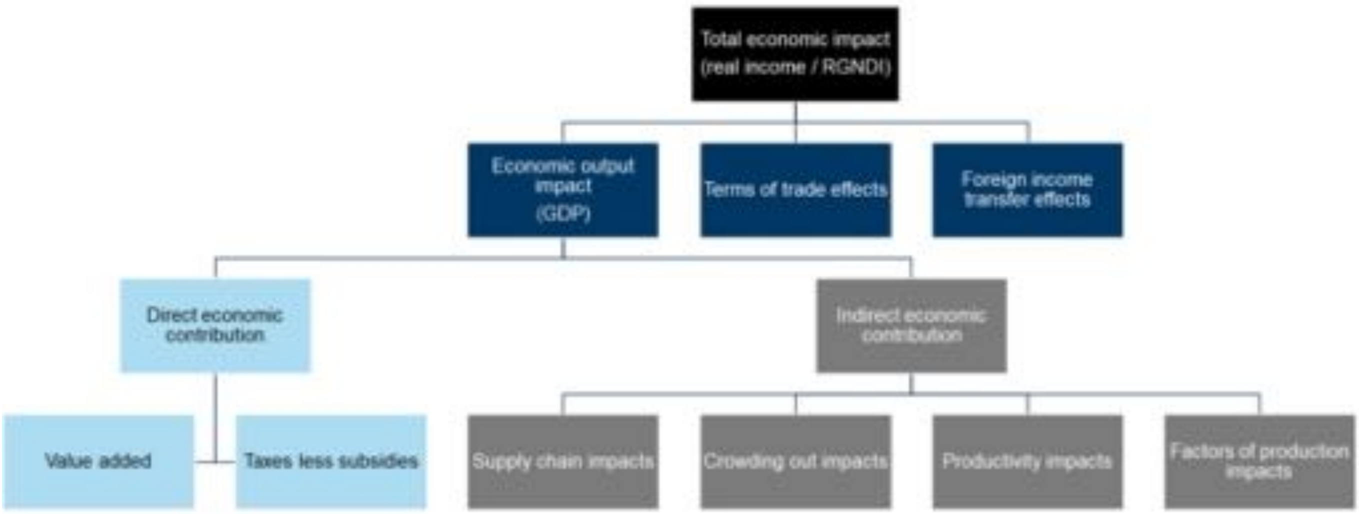
It is a multi-sector dynamic model of the Australian and world economy that has been used for many similar modelling projects including new power stations and interconnectors. Inputs will be taken from the cost benefit analysis and the network, electricity market and Marginal Loss Factor (MLF) modelling to develop the base case (the reference case) and each policy scenario.

The differences between the economic projections of the base case and the various policy scenarios will provide a forecast of the total economic impacts of each scenario. These include the wider economic impacts associated with the scenario, as well as the impact of changes in the electricity market prices and network losses, as relevant.

CGE models produce a wide variety of economic metrics. The metrics to be reported in this case are as follows:

- Real economic output: (as measured by real Gross Regional Product (GRP) and real Gross State Product (GSP) or Gross Territory Product (GTP), the sub-national versions of gross domestic product or GDP) is defined as the sum of value added by all producers who are within the region/state, plus any product taxes (minus subsidies) not included in output.
  - A positive deviation (i.e. increase) of real economic output from the base case implies that the scenario will enable the economy to produce more real goods and services potentially available for consumption.
- Real income: the change in CGE models, such as *Tasman Global*, is a measure of the change in economic welfare of the residents of the region, state or country.
  - The change in real income is equal to the change in real economic output plus the change in net foreign income transfers plus the change in terms of trade. In contrast to measures such as real economic output, real income accounts for any impacts of foreign ownership and debt repayments, as well as changes in the purchasing power of residents as a result of a project or policy.
- Employment and real wages: impacts on employment and wages under each scenario are produced by *Tasman Global*.

Figure 42 ***Estimating the macroeconomic impact of a project or policy***



Source: ACIL Allen

4.3 Electricity system network analysis

This section shows the approach to electricity system network analysis that has been used consistently across all power modelling that has been performed to identify and quantify future levels of investment into the Evoenergy electricity network to maintain the network to current levels of safety, security and reliability. Identifying the level of investment aids in identifying the cost that would be passed on to energy consumers.

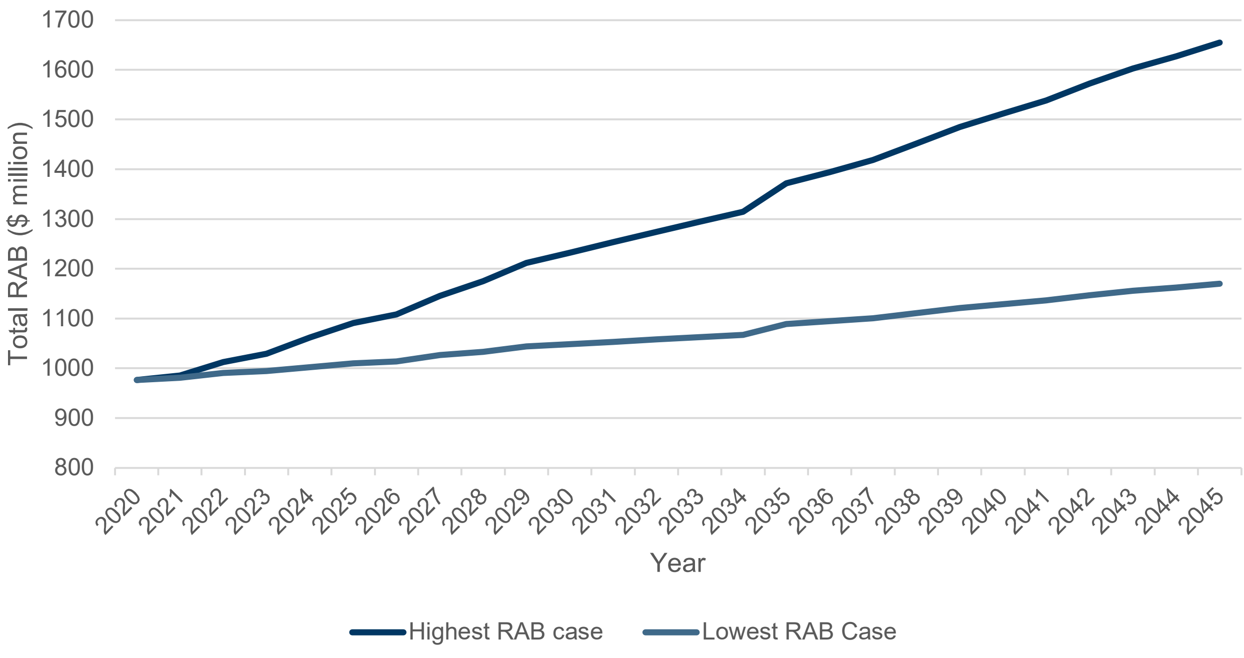
To estimate the change in costs to consumers, the network RAB size is considered as a relative measure of network size that can be referenced for determining cost passed onto consumer. Growth in the RAB is dependent on a combination of the mix of investments that are performed on the network and the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

Growth 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.

Assets added to address specific DER have not been included as they are typically larger and funded by the customers connecting the large 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 43 the range of the RAB between the most extreme cases is shown. All other modelling only considers the worst-case (highest) scenario RAB.

Figure 43 ***Comparison of highest and lowest possible RAB outcomes, base case***



Source: GHD

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. 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.

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. These planned works have been factored into the modelling and the timing of these works are adjusted where appropriate based on the changes in the forecast for each scenario.

In all forecasts 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.

4.3.1 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 EVs. 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 being (1) 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 Australian Energy Regulator's (AER's) website; and (2) 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.

Historically the make-up of this type of expenditure in the Evoenergy network is categorised as shown in Table 5.

Table 5 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%

4.3.2 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 6 details the planning rules used for each asset type.

Table 6 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 44 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.

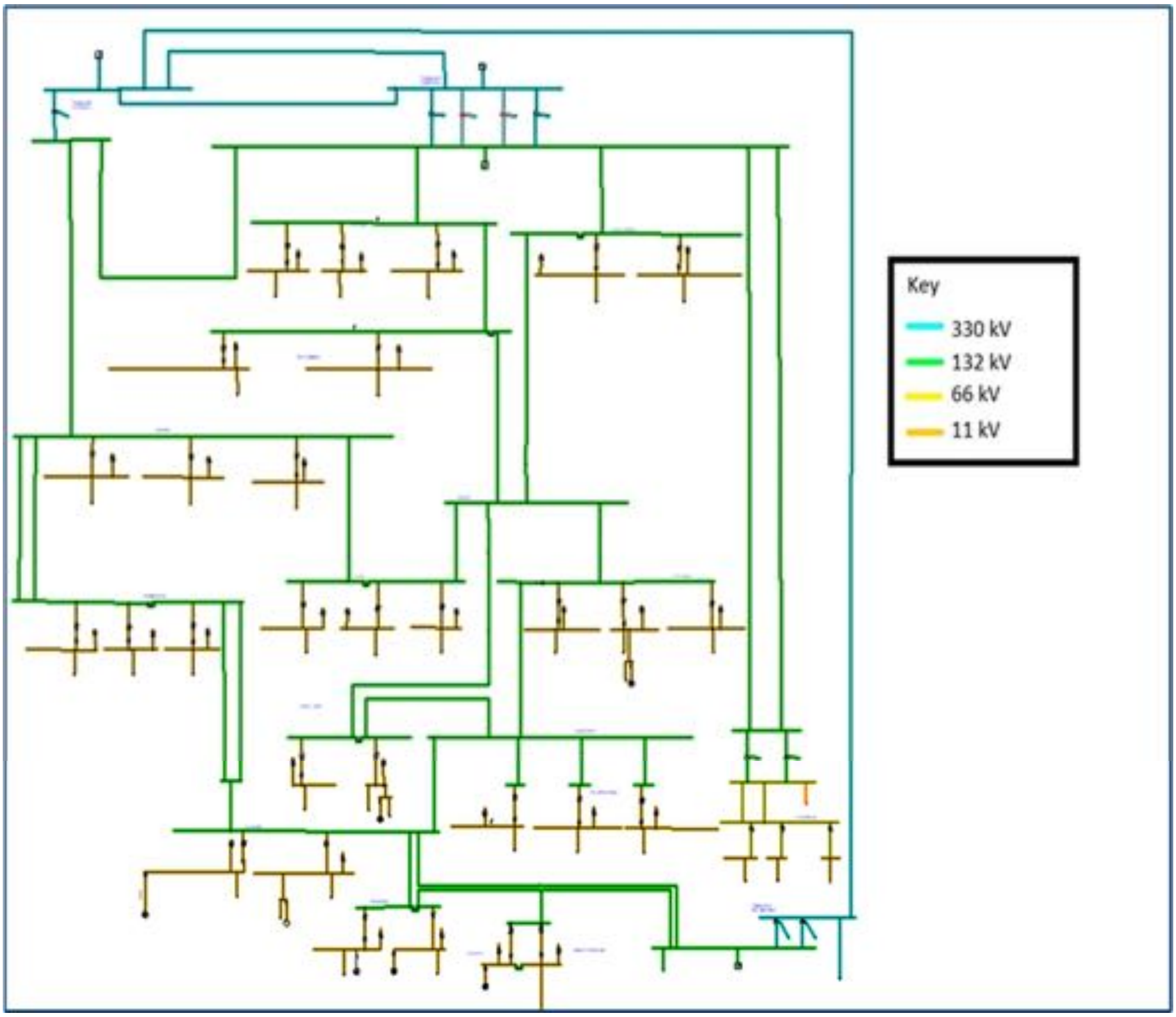
The output of the Sincal simulations is the loading on each sub transmission line and the percentage of the loading compared to the thermal rating of the line.

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.

After all three models have been checked, another check is performed to identify if investments of one type, impact the investments of another. For example, 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 two lines when one may suffice).

Figure 44 *Evoenergy network depicted in 2021 in Sincal*



Source: Sincal

4.3.3 Location non-specific growth in 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. The main supply quality issue created by the installation of additional DER typically relates to voltage rise within low voltage network equipment. If enough DER is installed without any effort to address the issue, low voltage customers (typically residential and commercial customers) may start to see appliances fail within their premise due to excessive supply voltage.

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. It is expected that any other works such as LV augmentations would be cheaper than the allowance for the transformer replacement and that majority of cases would be resolved with the transformer.

4.4 Simulation models

ACIL Allen's in-house simulation models, *GasMark* and *PowerMark* and were used for the detailed modelling of the electricity network against the base case and the three scenarios as set out in this report. To provide information on the broader economic impacts on the ACT economy potentially arising from the scenarios ACIL Allen's CGE model, *Tasman Global* was used. Further detail regarding *GasMark*, *PowerMark*, and *Tasman Global* is provided in Appendix B.

4.5 Key data inputs

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

5. Base case modelling

This Chapter sets out a summary of the **Base case Report** results.

5.1 Description

The **Base Case Report** set out the results of economic and technical modelling of the agreed base case. The underpinning assumptions for the base case modelling were 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. Current and expected market trends were overlaid with parameters drawn from existing Government policy settings/announcements to further inform the base case modelling.

5.2 Key variables

The key variables for the base case are detailed in Table 7.

Table 7 Base case variables

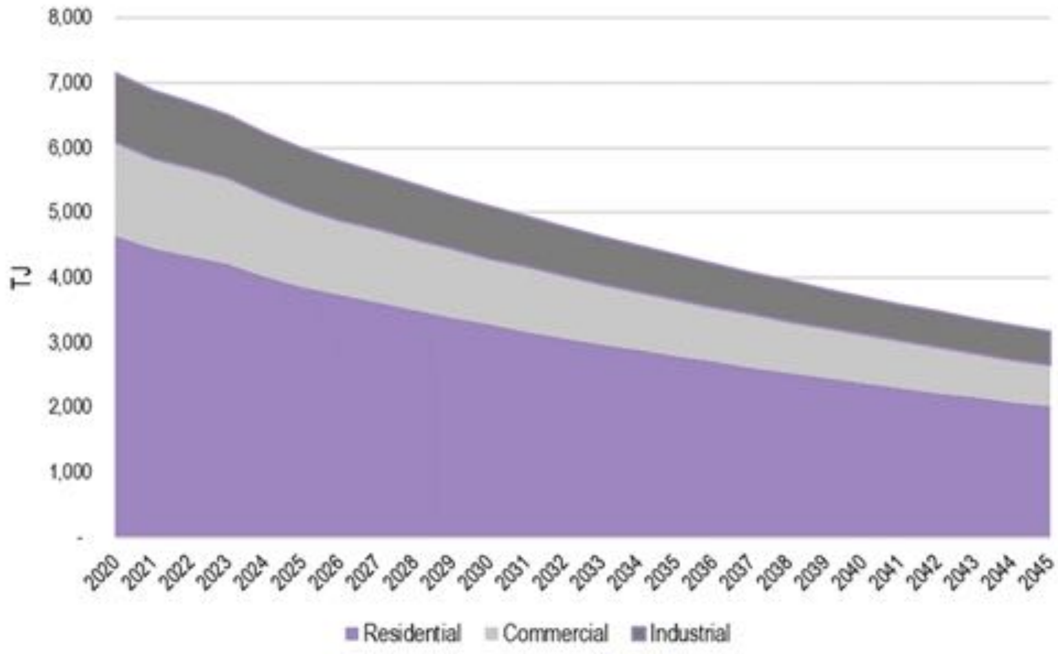
Variable	Description	Base case
Demand for gas from gas network	Change compared from current level of gas demand (note that any gas supplied is either biogas or hydrogen (actual or offsets))	~60% reduction
Rate of gas household electrification	Percentage of existing gas customers that switch to electricity each year	0.85% pa
Residential rooftop PV uptake (by 2045).	Percentage of households with suitable roof space on which PV panels have been installed	47%
Residential batteries uptake	Percentage of installed domestic PV systems with batteries	25%
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%
Batteries	Amount of large-scale battery storage installed by 2045	660MW
	Amount of neighbourhood/community battery storage installed by 2045	zero
Energy efficiency	Level of energy efficiency (low/moderate/high) Annual energy savings (GWh) in 2045	Low/moderate energy savings of around 485 GWh by 2045 In line with current trajectory No change from current building standards
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes autonomous vehicles (Avs) – all assumed to be electric)	41%
Use of EVs for V2H and V2G	Percentage of EVs that are used as 'batteries' to supply homes (V2H) or the grid (V2G).	zero
Demand for electricity from grid	Relative measure of the demand for electricity that is supplied by the grid	High

5.3 Gas market projections

5.3.1 Gas consumption

While overall gas consumption has been relatively stable over the past decade, consumption has been steadily declining on a per connection basis. The Centre for International Economics analysed Evoenergy data in its demand forecast report for the current access arrangement period.[8] Its analysis showed residential demand per connection declined by 35 per cent over the period from 2003 to 2018 (from around 52 GJ per annum to 34 GJ per annum, representing a 2.3 per cent drop per year). As indicated in Figure 45, modelling shows that the ACT's total gas consumption will drop from levels around 7,000 TJ currently to around 3,000 TJ by 2045 – representing a decline of approximately 60 per cent. Most of this decline can be attributed to falling consumption per connection, coupled with a steady decline in connections from 2023 and the impact of ACT's current climate change policies. This decline is a marked change from consumption over the past decade which has been relatively stable.

Figure 45 Projected total gas consumption – ACT

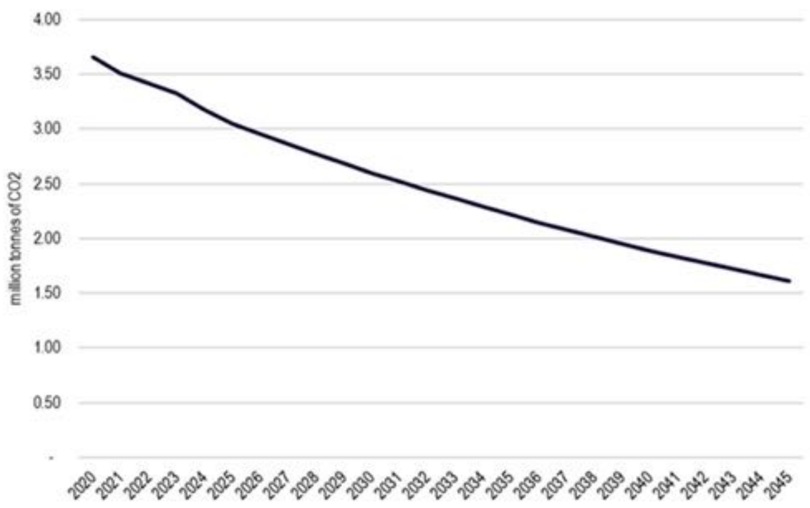


Source: ACIL Allen analysis

As indicated in Figure 46, and in line with projected gas consumption, the 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 (representing a 57 per cent reduction in emissions).

[8] CIE: Demand forecasting report - ACT and Queanbeyan-Palerang gas network 2021–26, June 2020.

Figure 46 Natural gas projected emissions



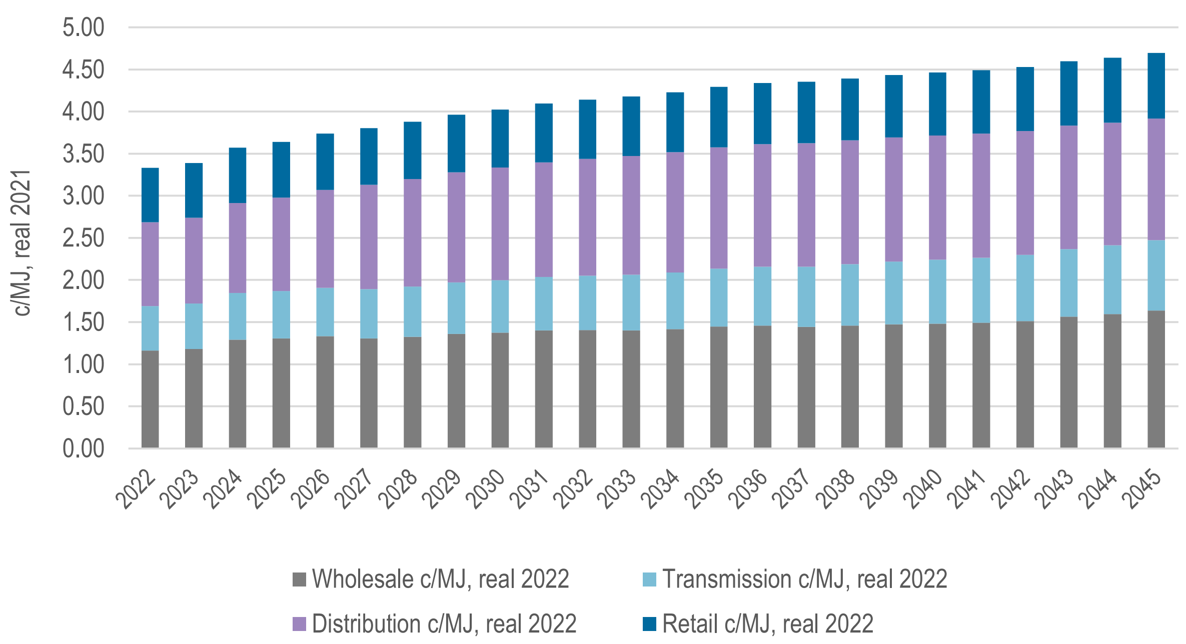
Source: ACIL Allen analysis

5.3.2 Gas retail price

The total delivered natural 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. The retail price would noticeably increase over the first 10 to 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. The total delivered retail price projected over the projection period is presented below in Figure 47.

For a typical residential user consuming around 35 GJ per annum, their bill in 2022 would be around $1,155. In 2045, their bill would have increased to $1,575, representing a 36 per cent increase.

Figure 47 ACT retail price for gas delivered to residential customers



Source: ACIL Allen analysis

5.3.3 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.

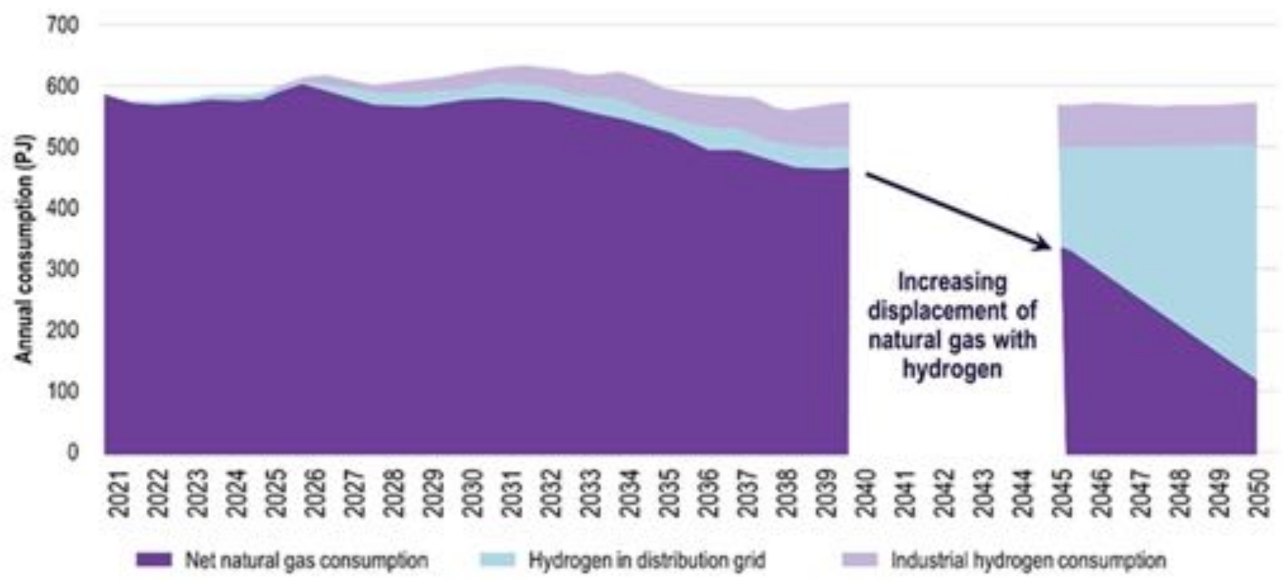
With demand for natural gas projected to decline by around 60 per cent reduction in gas consumption by 2045, the distribution network in terms of its long-term viability will be impacted including the consequences for gas prices.

The AER is reviewing implications of shortening asset lives on regulatory parameters including depreciation schedules. This will have important implications for how Evoenergy operated the ACT network and the removal of natural gas from the energy mix across the Territory.

5.3.4 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. For example, 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 48.

Figure 48 AEMO assumed hydrogen impact on natural gas consumption 2021-2050



Source: AEMO

Currently, hydrogen strategies are primarily focused on large-scale industrial applications and export opportunities, and as such the ACT presents limited potential. Complex challenges will need to be overcome if natural gas in the ACT's energy system is to be replaced with hydrogen. 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.

5.3.5 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.

5.4 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 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.

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 75-80 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 assumptions for the remaining gas consumption is hot water (~25 per cent) and cooking (~two per cent). For non-residential customers, the assumptions 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.

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.

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). Table 8 sets out the assumed conversion rates for the main uses.

Table 8 Gas to electricity conversion factors – main uses

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 hot water efficiency of 85%.
Cooking	0.75	40%	0.15	Average performance of electric cookers 75%. Average gas cooker efficiency of 40%.

Note: Conversion rate = 0.277778*efficiency*1/performance
Source: ACIL Allen analysis based on gas efficiency information from Elgas.com.au and COP information from various heat pump manufacturer specifications.

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

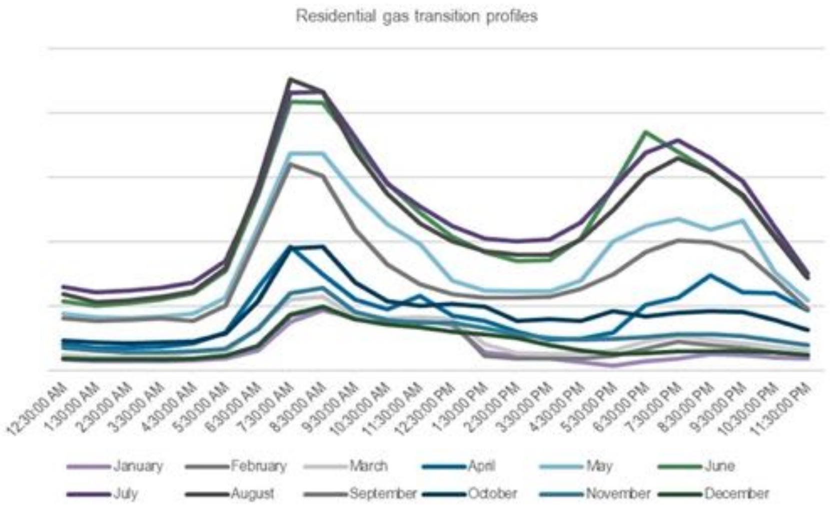
- using the past three years of actual gas demand data (converted to electricity demand using the method described above) as well as the past 20 years of weather data, we have used a matching algorithm to produce 20 sets of weather-related gas transition demand profiles of 17,520 half-hourly loads
- 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.

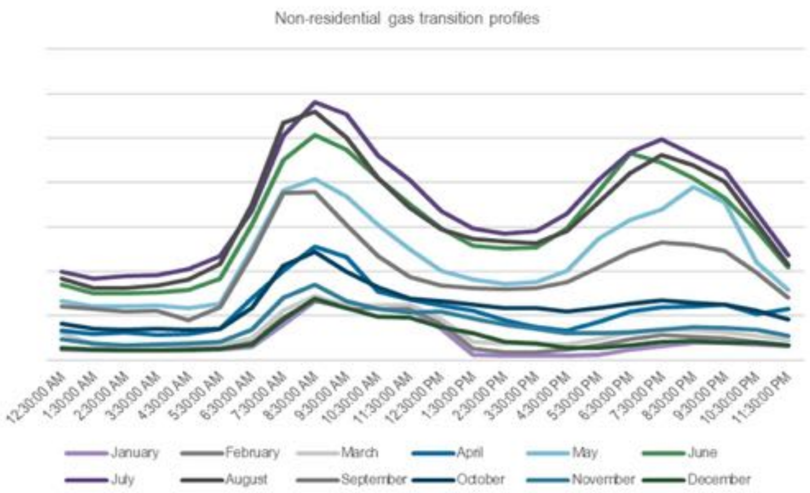
Average seasonal time of day electricity demand profiles for the gas transition component by residential and non-residential customers are provided in Figure 49.

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. Both segments of the market show high demand from gas conversion during the winter months in the morning and evening periods.

Figure 49 Average seasonal time of day electricity demand profiles for gas transition customers – residential and non-residential customers





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

Final assumed annual energy and peak demand projections (shown in Figure 50 and Figure 51), derived from the assumed underlying demand, together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, result in a modest increase in electricity energy requirements of 21 per cent by 2045, despite compensating for 60 per cent loss of gas demand. ACT 50POE peak grid 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.

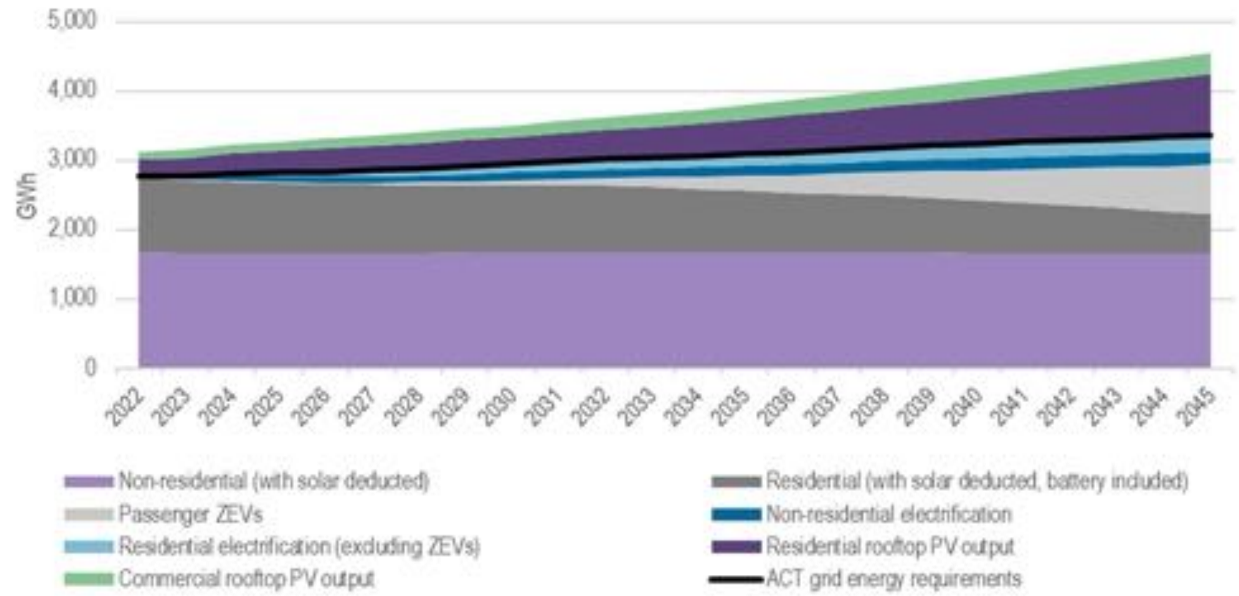
The growth in peak demand is predominantly driven by electrification of space heating requirements during winter mornings. Home batteries are assumed to charge during the middle of the day and discharge during the evening peak (which includes the increase in demand from electrification of space heating requirements during winter evenings).

Key factors encompassed in this outcome include:

- delivery of 26 per cent of total demand through rooftop PV by 2045
- ZEVs comprise 41 per cent of car fleet by 2045 (producing no emissions, but adding to electricity demand)

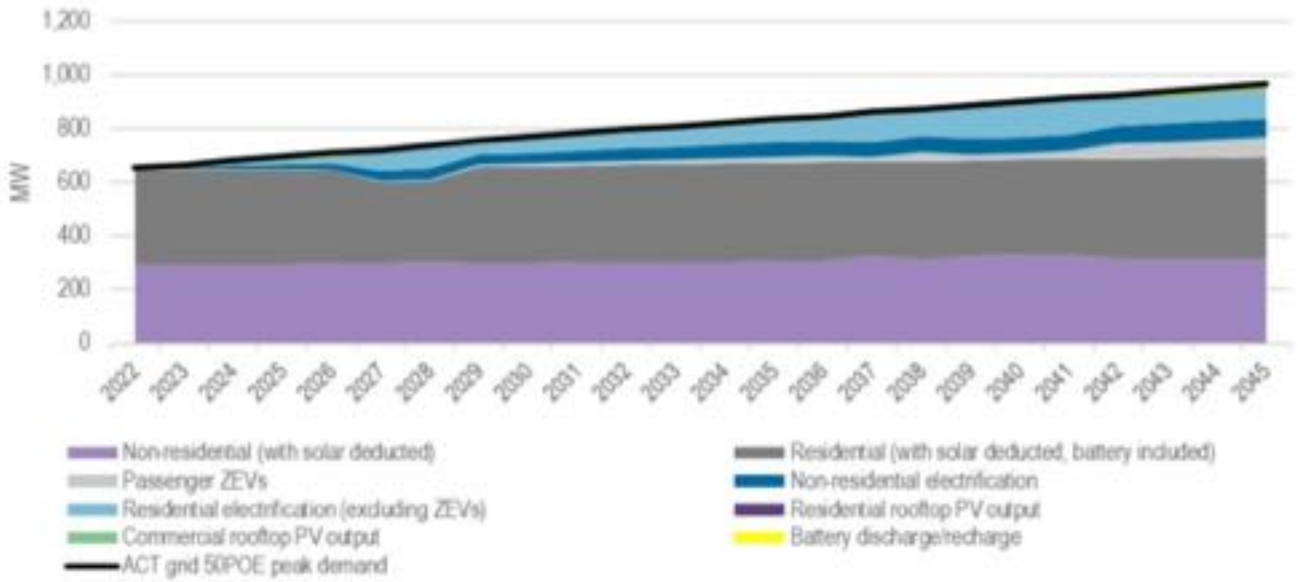
- the continued hollowing out of the demand profile across daylight hours because of rooftop PV, and a growth in demand during the evening because of electrification
- the impact of storage on the demand profile is reasonably small given the level of uptake projected.

Figure 50 Projected annual energy requirements (GWh) – by category – base case



Note: V2H is included in Passenger ZEVs. Grid energy requirements (grid demand) is defined as all the electricity sourced from the grid, at the point of the consumer's meter. 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 51 Projected annual 50 POE peak demand (MW) – by category – base case



Note: V2H is included in Passenger ZEVs. Grid 50POE peak demand refers to the maximum amount of electricity sourced from the grid at any one time, at the point of the consumer's meter, and is measured in megawatts (MW). 50 "probability of exceedance" (POE) refers to the median or middle value in a range of peak demand outcomes that could be expected to occur. 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 P50 peak 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

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 2038, declining to around 70 per cent by 2045. This suggests the Government could need to factor in a further auction of renewable electricity in around 2036. 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 should more than offset the need for additional purchases. 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. This change will largely offset the continuing need to purchase 100 per cent renewable electricity.

5.5 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.

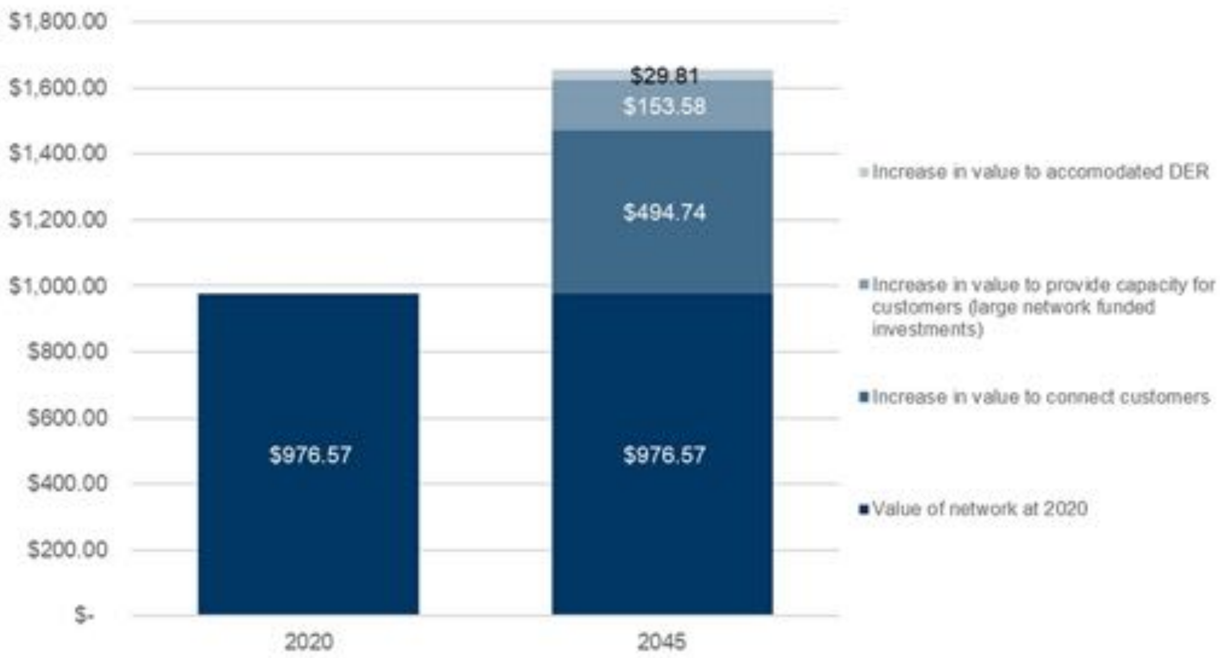
The investment identified in the ACT network in the base case is predominantly located in the areas of high population growth in the ACT - many low population growth areas are not expected to see significant investment during the period analysed. However, if a more aggressive approach to the transition 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 up to an additional $678 million in the network to 2045 (up from the 2020 valuation of $977 million).

The relative magnitude of the growth in the various segments of the network are shown in Figure 52 and Figure 53 below.

Figure 52 Cumulative change in RAB in base case by investment type

Source: GHD

Figure 53 Change in value of the distribution network asset base from 2020 to 2045 in the base case, $ million



Source: GHD

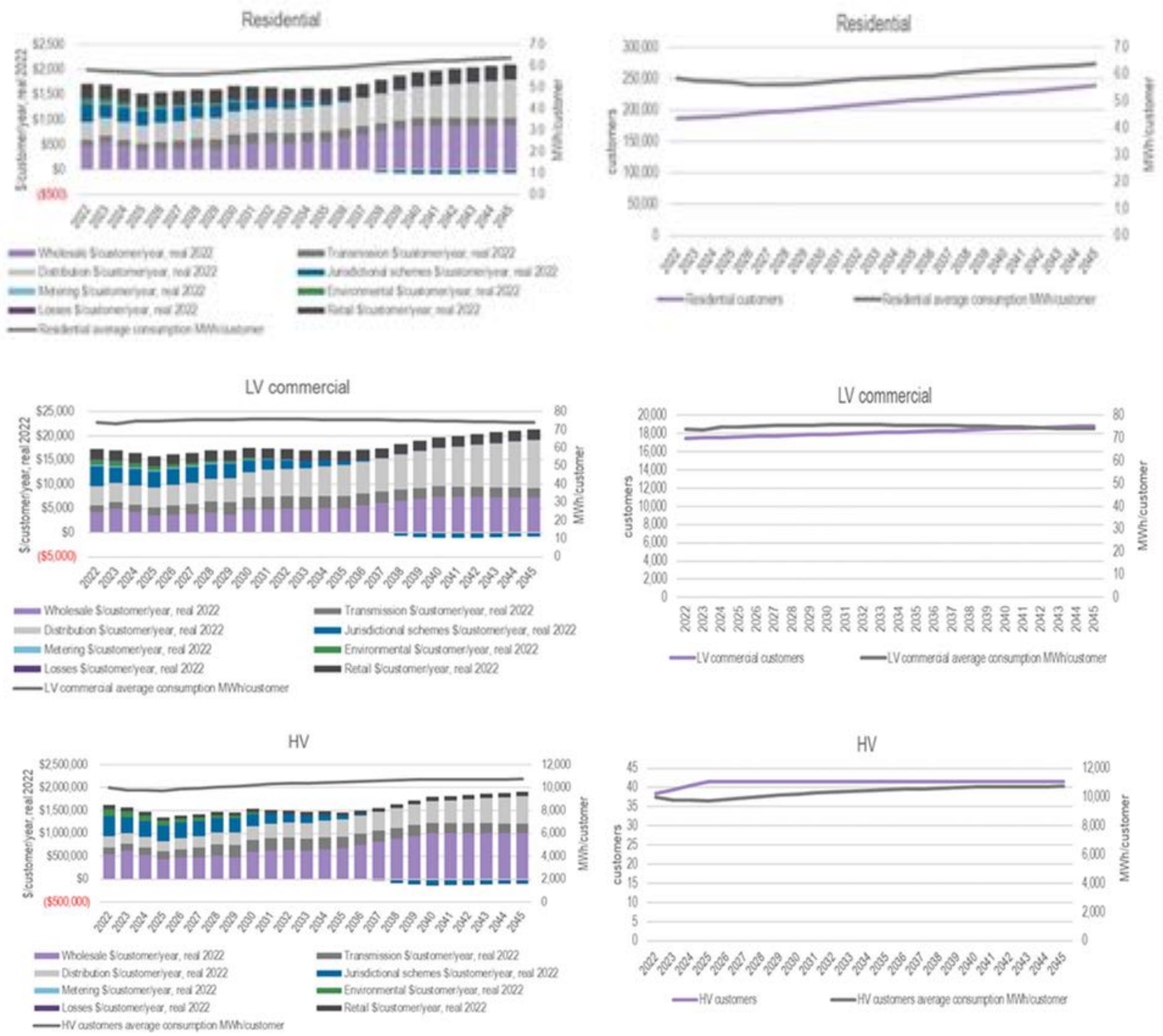
5.6 Electricity bill impacts

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 there is little retail price impact as a result of electrification, coupled with the increased uptake of PV and ZEVsFigure 54. This is due to any increases being 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 one per cent and nine per cent respectively (reflecting projected declines in large FiT payments and costs associated with Commonwealth environmental schemes, with these declines offset by projected increases in wholesale and network costs in the case of residential customers).
- 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).

Figure 54 *Projected retail price (left chart) (c/kWh, real 2022) (LHS) and average consumption (MWh/customer) (RHS); Projected customer numbers (right chart)*



Source: ACIL Allen

5.7 ACT economy-wide analysis

As discussed in Section 4.2.2, CGE modelling has been undertaken to estimate the macroeconomic impacts of the alternative scenarios relative to the base case. For the CGE modelling of the base case itself, population growth has been taken from the suburb level projections provided to ACIL Allen by ACT Treasury[9], which has the population of the ACT increasing from 430,667 in 2020 to 550,352 in 2045.

Forecasts of the annual growth in the ACT real GTP through to 2024 have been taken from the ACT 2020-21 Budget Outlook (Table 2.2.1), with per worker productivity growth after that period taken from the 2021 Intergenerational Report.[10]

[9] 2021, Suburb Total Projection 2011-2060, ACT Treasury, Microsoft Excel File.
[10] The Commonwealth of Australia (2021), 2021 Intergenerational Report Australia over the next 40 years. Available at: **https://treasury.gov.au/publication/2021-intergenerational-report**

Residential and commercial energy demand and pricing has been calibrated to the volumes and values presented above. In addition, the demand for petrol for ICE and hybrid vehicles has been calibrated to the vehicle numbers and average kilometres travelled per vehicle were taken from the ‘conservative’ EPSDD projections (as per the provided Deloitte analysis).[11]

Fuel demand for passenger vehicles is based on DITRDC (2021)[12], which has average fuel efficiency increasing gradually from 10.3 litres/100 km in 2021 to 8.4 litres/100 km by 2045.

Fuel prices are projected to increase gradually to $2.05 cents/litre based on the long-run crude oil price projections under the Stated Polices Scenario (SPS) in the IEA’s World Energy Outlook 2021, which project that the price of oil will be US$82/barrel in 2020 prices by 2040. An exchange rate of A$0.73/US$ was applied to convert to Australian dollars.

[11] 2021, ACT Zero Emission Vehicles Uptake Forecasts, Deloitte, Microsoft Excel File
[12] DITRDC (2021), Light vehicle emission standards for cleaner air, Draft Regulation Impact Statement, October 2020

6. Scenario 1: *Technology drives change*

This Chapter sets out a summary of the Scenario 1 techno-economic modelling results.

6.1 Scenario description

The *Technology drives change* 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. The key variables for Scenario 1 *Technology drives Change* are detailed at Table 9.

Table 9 Scenario 1 Technology drives change: key variables

Variable	Description	*Technology 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))	~80% reduction
Rate of gas household electrification	Percentage of existing gas customers that switch to electricity each year	1-2% p.a. (linear)
Residential rooftop PV uptake (by 2045).	Percentage of households with suitable roof space on which PV panels have been installed	60%
Residential batteries uptake	Percentage of installed domestic PV systems with batteries	65%
Commercial PV & battery systems	Percentage of suitable commercial roof space with installed PV systems (all commercial PV systems are assumed to include battery storage)	95%
Batteries	Amount of large-scale battery storage (located on the network, 'in front of the customer meter') installed by 2045	760MW
	Amount of neighbourhood/community battery storage (located on the network, 'in front of the customer meter') installed by 2045	100MW
Energy efficiency	Level of energy efficiency (low/moderate/high) Annual energy savings (GWh) in 2045 Percentage change from base case	Moderate energy savings of around 685 GWh by 2045 (or around 40% more energy savings than base case)

Variable	Description	*Technology drives change*
		Based on ISP 'Net Zero[13] by 2050' scenario
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes autonomous vehicles (Avs) – all assumed to be electric)	68%
Use of EVs for V2H and V2G	Percentage of EVs that are used as 'batteries' to supply homes (V2H) or the grid (V2G) (based on the 'hydrogen superPower' scenario in the latest ISP assumptions workbook)	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

6.2 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 ZEVs increases slightly more rapidly than in the base case. Private ZEVs will make up 13 per cent of the fleet by 2030 (or approximately 42,000 ZEVs), 33 per cent of the fleet by 2035 (around 114,000 ZEVs) and 68 per cent of the fleet by 2045 (around 270,000 ZEVs). These figures align with the Deloitte 'optimistic' forecast.

Adoption of ZEVs 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 ZEVs.

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).

[13] Renamed 'Progressive Change' on 10 December 2021 ISP update.

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.

ZEVs can be used as batteries when they are not being used as transport. ZEVs can provide stored electricity either directly to the grid (V2G) or to the home (V2H).

- The number of ZEVs used to store and supply electricity in this way gradually increases.
- By 2030, 5 per cent of the ZEV fleet is used in this way (or approximately 2,100 ZEVs), increasing to 10 per cent by 2035 (around 11,400 ZEVs) and 26 per cent by 2045 (some 54,000 ZEVs). 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.

6.3 Gas market projections

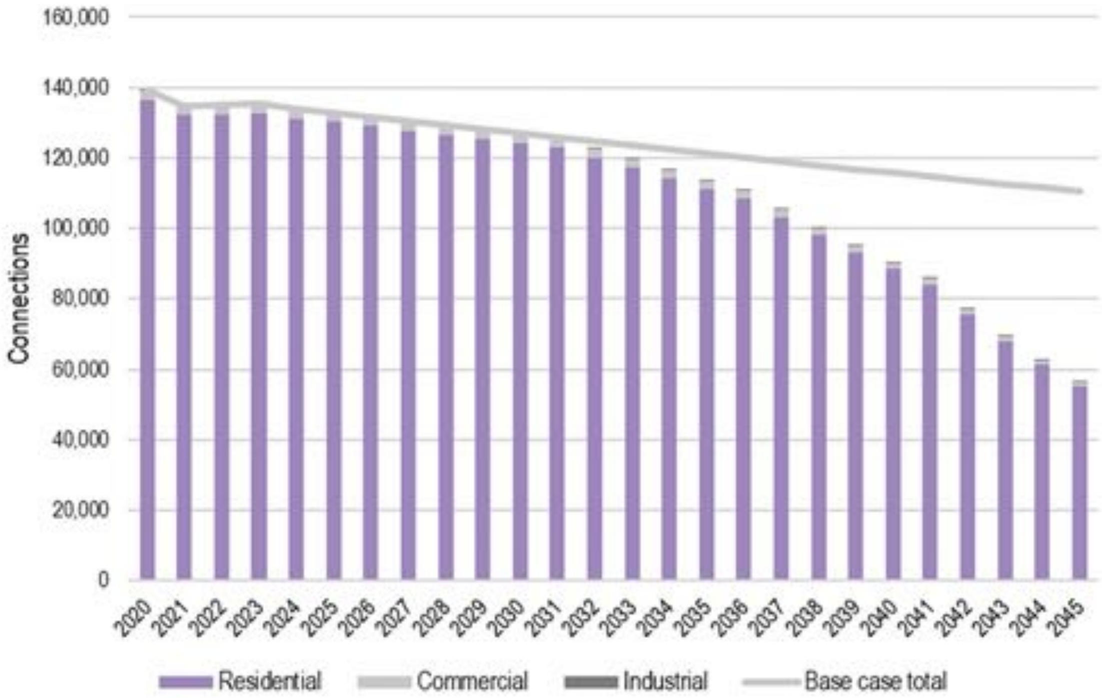
6.3.1 Connections

Projected gas connections in the ACT are provided in Figure 55.

This scenario assumes connections will decline at a steeper rate than the base case. Total connections in the ACT (excluding Queanbeyan) will drop from around 140,000 in 2020 to less than 60,000 in 2045. This represents a total loss of 80,000 gas connections, or a 60 per cent decline in connections from current levels.

Over the forecast period, connections on average fall by approximately 3.5 per cent per annum (with the large majority of connections falling post 2030, driven by gas prices and affordability considerations ramping up the rate of transition (including possible Government incentives)).

Figure 55 Projected gas connections, ACT – Scenario 1 vs base case



Source: ACIL Allen

Residential connections fall from around 136,000 in 2020 to 55,000 in 2045; commercial connections fall from around 2,800 in 2022 to 1,100 in 2045; and industrial connections fall from around 35 to 25.

Disconnection rates increase from around 1,200 disconnections per year over the late 2020s, to 3,000 per year in the early 2030s, 5,000 per year by the end of the 2030s, and a peak of around 8,500 per year in the early 2040s.

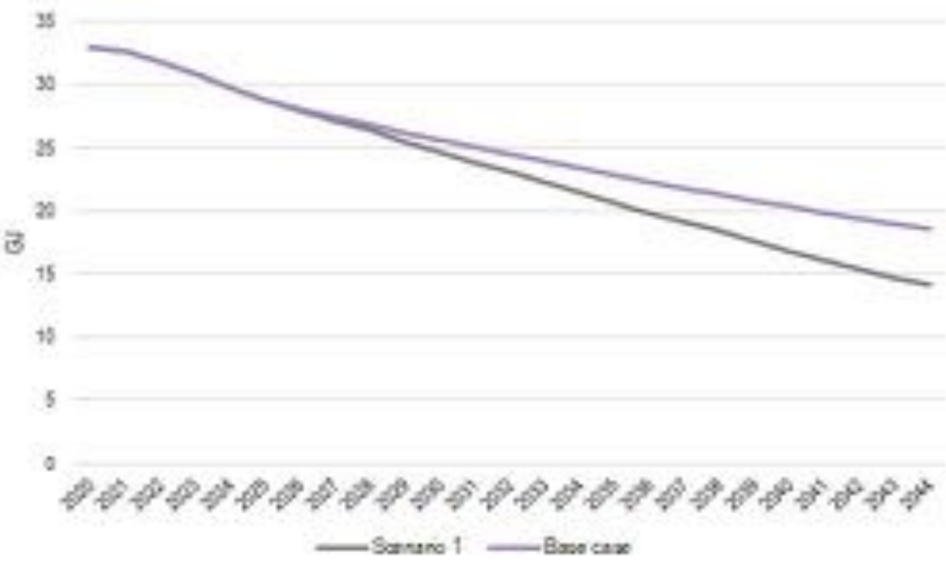
6.3.1.1 Consumption per connection

Residential and commercial

Residential consumption per connection is expected to drop from levels around 33 GJ per annum to 14 GJ per annum under this scenario. This means residential gas consumers are projected to consume around 57 per cent less than they currently do by 2045. The steeper decline assumes household efficiency and appliance efficiency improves more under this scenario than in the base case. This decline could be driven by a number of factors, for instance, an increased focus on improved gas appliance efficiency, customer responses to rising gas prices, targeted policy incentives etc.

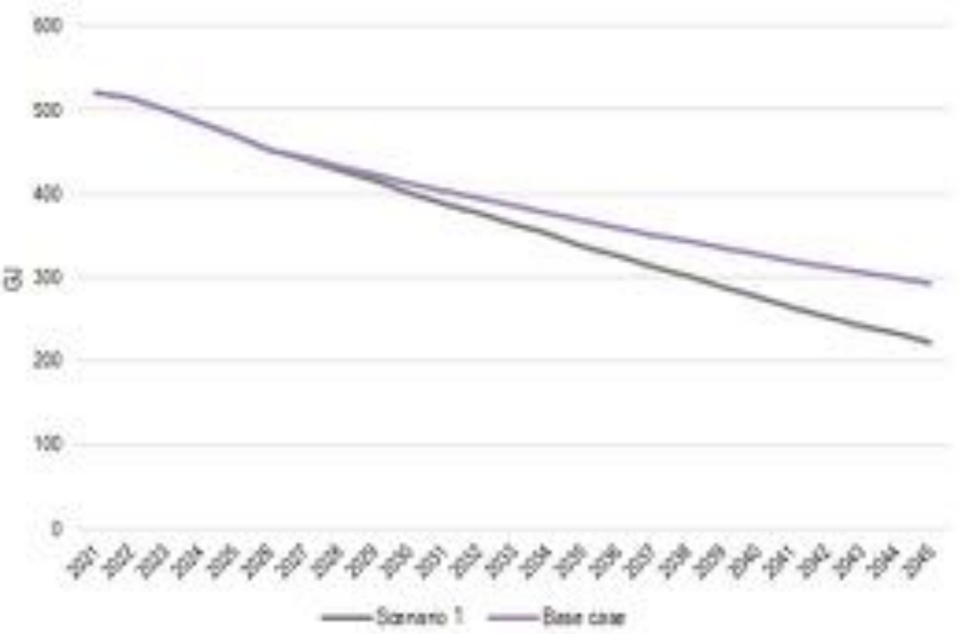
Most of the residential gas consumption is for heating, which accounts for approximately 75 per cent of household consumption. Hot water is next, representing around 20 per cent of consumption, followed by small amounts for cooking and ovens. Broadly, the improvement in energy efficiency is slightly higher for heating appliances compared with hot water and cooking appliances. Commercial consumption per connection is assumed to drop from levels around 520 GJ per annum to levels around 190 GJ per annum in 2045, declining at the same rate as residential connections. Projected residential and commercial consumption per connection is illustrated in Figure 56 and Figure 57.

Figure 56 ***Projected gas consumption per residential connection – Scenario 1 vs base case***



Source: ACIL Allen

Figure 57 ***Projected gas consumption – per commercial connection – Scenario 1 vs base case***



Source: ACIL Allen

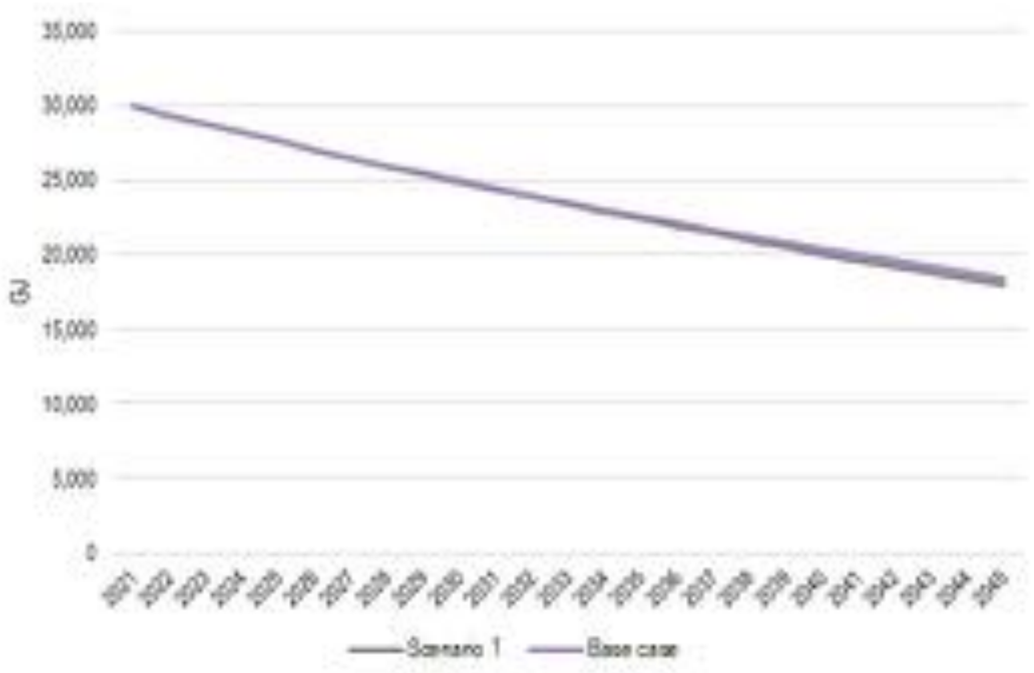
Industrial

Industrial gas consumption represents the smallest gas use 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.

Figure 58 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 18,000 GJ per annum, that is to a level slightly below that of the base case. The relative drop in industrial consumption is less than that for the residential and commercial sectors, given some industrial users are not able to reduce their gas consumption or replace it with other forms of energy to the same extent as residential or commercial customers.

ACIL Allen has considered that the reduction in consumption from the industrial sector will more likely come from sites/plants disconnecting from gas, rather than finding large efficiencies. Additionally, a number utilise gas as a feedstock and accordingly, are not in a position to reduce their use of gas.

Figure 58 *Projected gas consumption per industrial connection – Scenario 1 vs base case*



Source: ACIL Allen

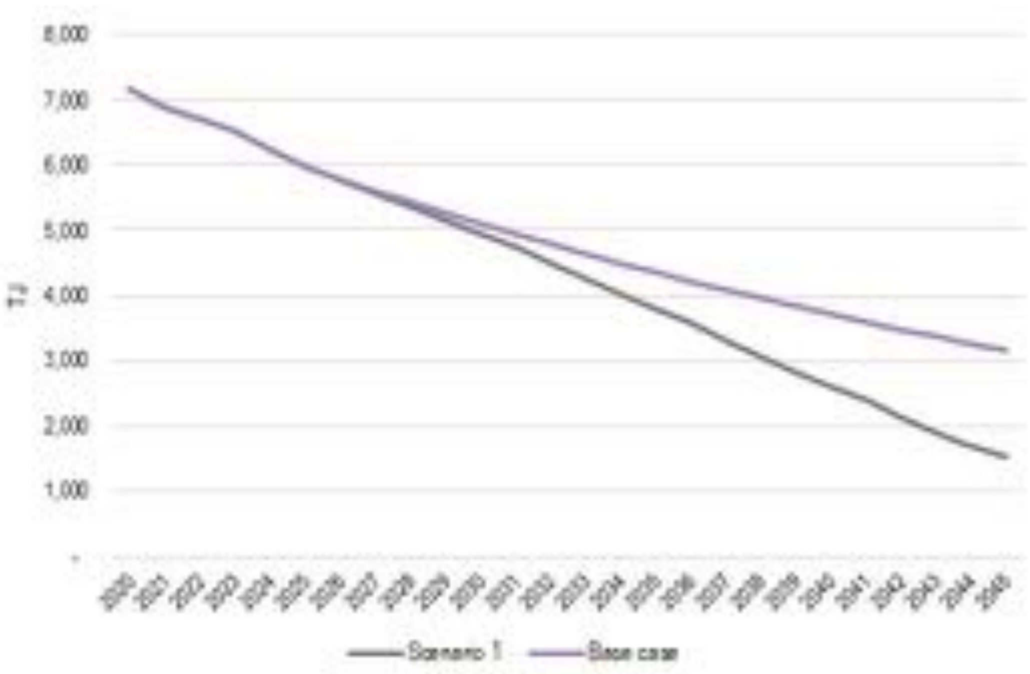
6.3.1.2 Projected total consumption

Total consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045. This represents a decline of approximately 80 per cent. This is compared with the base case in Figure 59.

The key driver over the long term for much lower volumes of gas consumed in Scenario 1 is the steeper decline in connections post 2030. By 2045, only 60,000 connections still consume gas in the Scenario 1 compared with around 110,000 connections in the base case. In terms of the rate of switching, Scenario 1 experiences switching rates rising from around one per cent in the 2020s, to 3 per cent in the 2030s, and almost 10 per cent by the 2040s.

The composition of consumption changes over the forecast period as residential consumption and commercial consumption decline at faster rates than industrial consumption. The residential share of total consumption declines from around 65 per cent in 2021 to 50 per cent by 2045. The share of consumption from the industrial sector increases from around 15 per cent currently to levels around 35 per cent by 2045. Accordingly, the Evoenergy network becomes more reliant on industrial gas users over the next two decades.

Figure 59 Projected total gas consumption, ACT – Scenario 1 vs base case



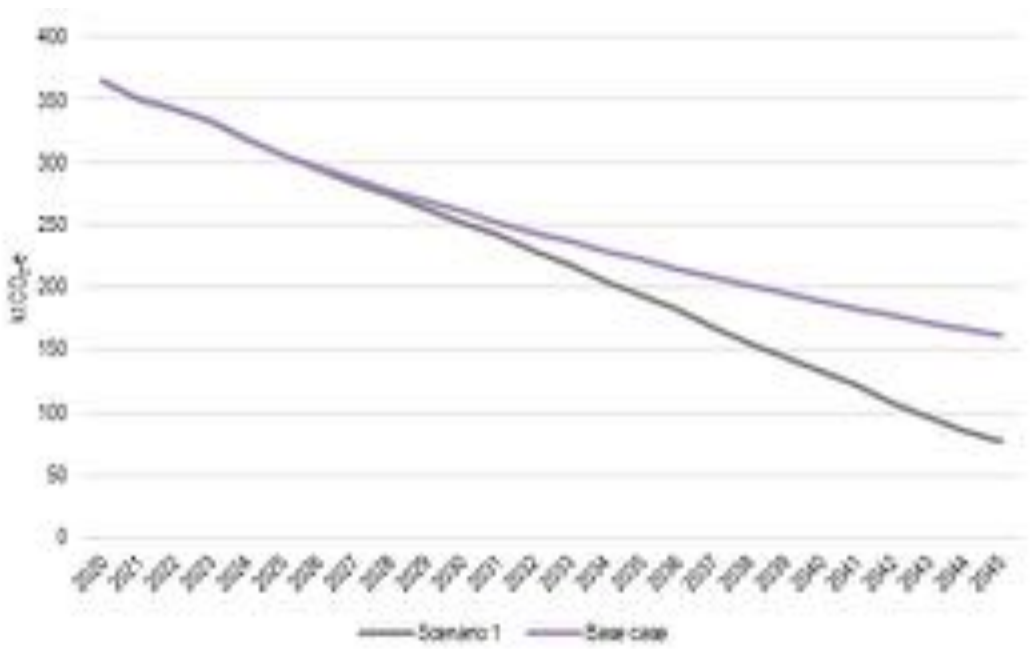
Source: ACIL Allen

6.3.2 Implications of demand forecasts

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 350 kilotonnes (kt) of CO_2. This would reduce to levels around 80 kt by 2045. Emissions are presented below in Figure 60.

Figure 60 Natural gas projected emissions – Scenario 1 vs base case



Source: ACIL Allen

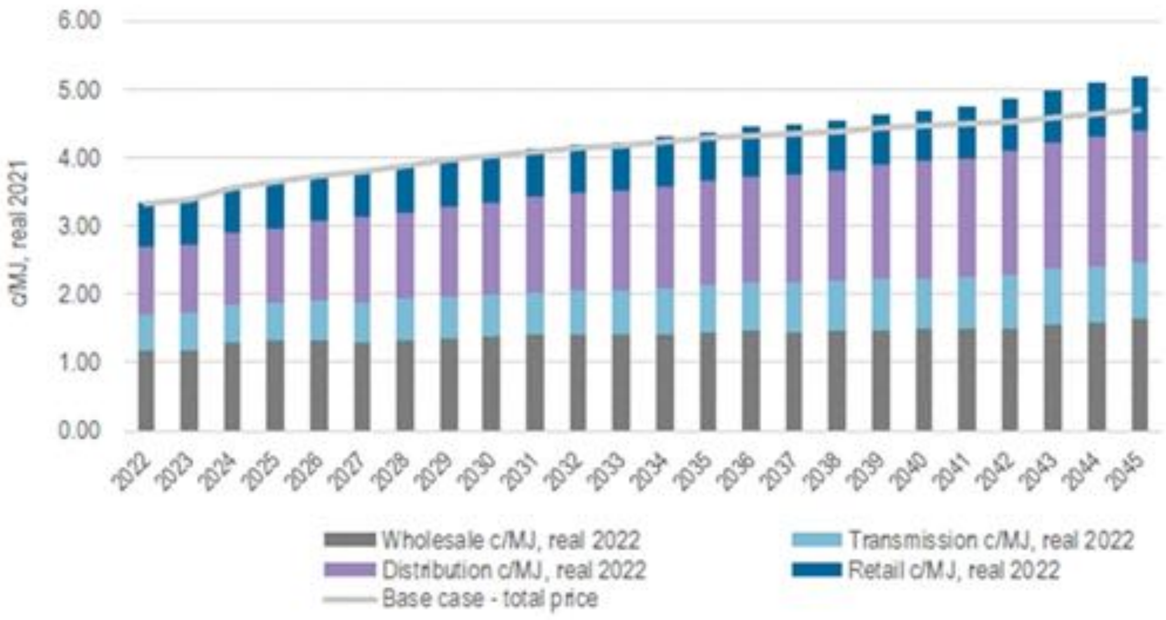
6.3.2.1 Gas pricing: retail prices

The total delivered retail price projected over the projection period is presented below in Figure 61. The price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s. This means for a household consuming around 35 GJ per annum[14], their residential gas bill would increase from around $1,155 per annum to levels near $1,820 per annum (compared to $1,645 per annum for the base case). The retail price steadily increases over the entire projection period and post 2030, retail prices under Scenario 1 begin to edge higher than the base case as larger numbers of customers disconnect from gas. The projected increase in distribution tariffs is the major driver impacting price. Analysis around the tipping point and sensitivity on how the AER would regulate prices is assessed in Chapter 9.

To meet the net zero goals, any remaining gas being delivered to customers by the end of the forecast period will need to be green gas (hydrogen or biogas), or with offsets in place. Some of this energy could be produced in the ACT or secured by offsets from the broader market.

The value of the offset would be based on the value of hydrogen or biogas at the time. As mentioned in the **Base case Report**, hydrogen is currently uncompetitive against natural gas (currently around $5/kg - equivalent to around $40/GJ). However, predictions are that the price of hydrogen will be somewhere around $2/kg ($16/GJ) by 2040.[15] This implies that in 2045, the value of an offset for the 1,500 TJ of remaining gas might be worth around $24 million. However, given current levels of interest/investment in hydrogen technologies, the cost of hydrogen could be lower than this by 2045.

Figure 61 ACT retail price for gas delivered to residential customers



Source: ACIL Allen

[14] Frontier Economics: Residential energy consumption benchmarks - Final report for the Australian Energy Regulator | 9 December 2020
[15] Advisian: *Australian hydrogen market study*; 24 May 2021

6.4 Electricity market modelling

We have adopted the same econometric approach to forecast peak demand and energy consumption in the ACT as was used for the base case. The modelling outcomes in relation to the key parameters varied from the base case are discussed in turn below.

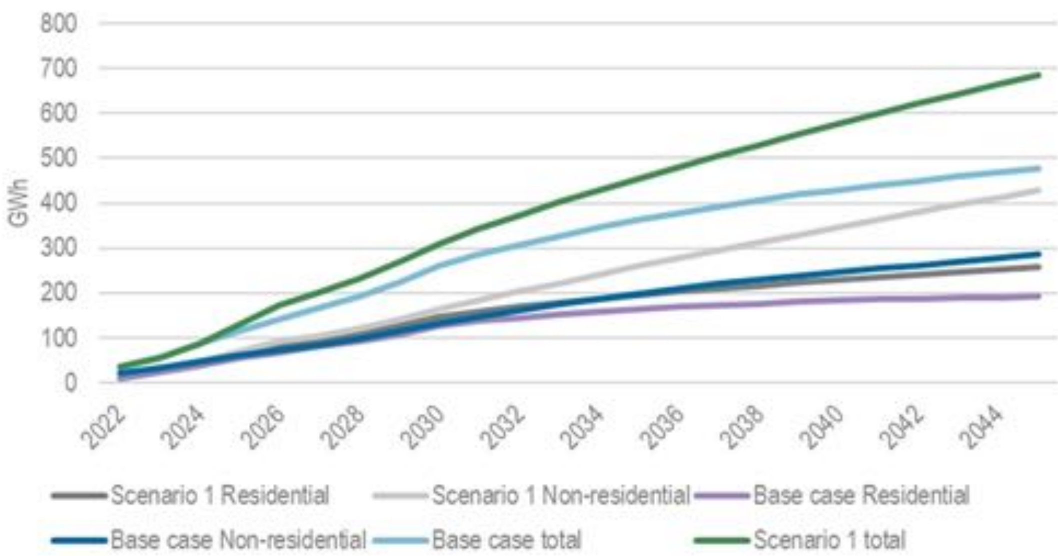
6.4.1 Energy and peak demand forecasts

6.4.1.1 Energy efficiency

Scenario 1 assumes a moderate level of energy efficiency with savings of around 685 GWh by 2045 or around 40 per cent more energy savings than the base case (see Figure 62).

Scenario 1 is based on AEMO's ISP 'Net Zero by 2050' scenario[16] and assumes NCC of 6.5 stars in 2025, 7 stars in 2039, 7.5 stars in 2047. As discussed in the **Base case Report**, the scenarios include an explicit amount of energy efficiency savings which equal the amount of energy savings in GWh over and above the base case level.

Figure 62 Projected energy efficiency (GWh) – Scenario 1 vs base case



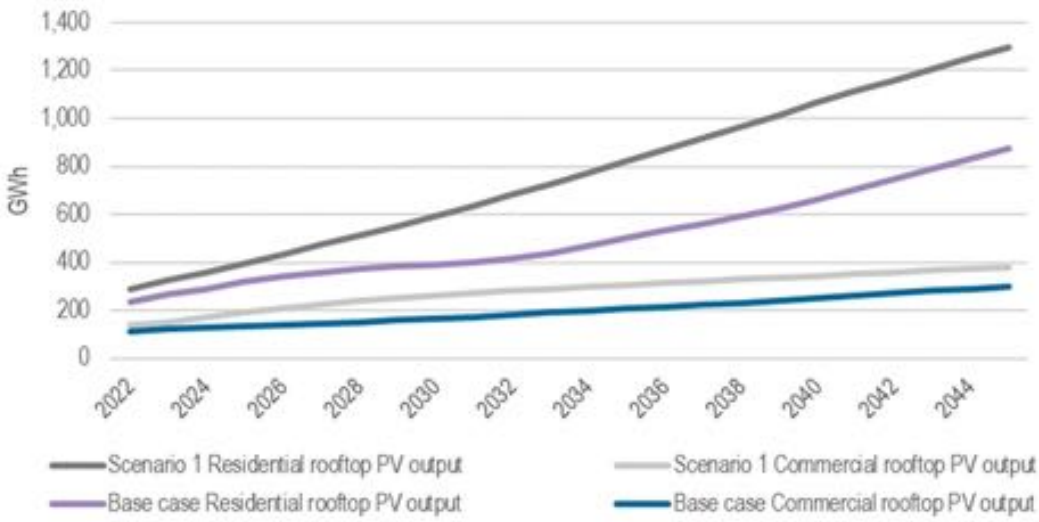
Source: AEMO ISP, ACIL Allen analysis

6.4.1.2 Behind-the-meter solar and battery energy storage systems

Scenario 1 assumes residential and commercial rooftop PV uptake reaches 60 per cent and 95 per cent of suitable rooftops, respectively, compared to 47 per cent and 90 per cent under the base case (see Figure 63).

[16] AEMO changed the name of 'Net Zero by 2050' scenario to 'Progressive Change' scenario in its 10 December 2021 consultation draft update.

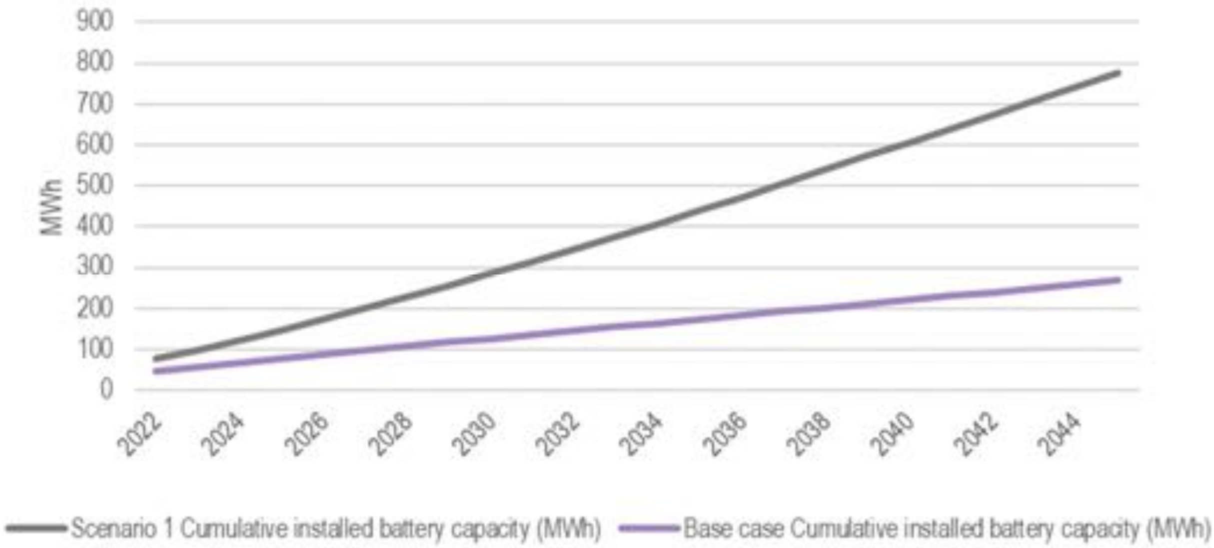
Figure 63 ***Projected rooftop PV output in the ACT, by consumer type (GWh) – Scenario 1 vs base case***



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

Scenario 1 assumes behind-the-meter (BESS) uptake reaches 65 per cent by 2045, compared to 25 per cent in the base case (see Figure 64).

Figure 64 ***Projected cumulative installed behind the meter BESS capacity (MWh) in the ACT – Scenario 1 vs base case***

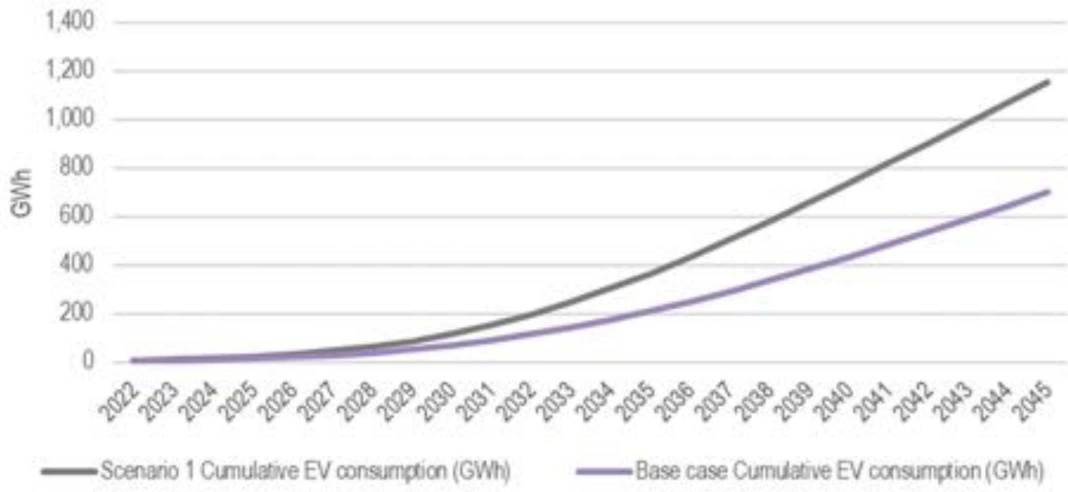


Source: ACIL Allen

6.4.1.3 Zero emission vehicles (ZEVs)

Scenario 1 assumes ZEV uptake reaches 68 per cent by 2045, compared to 41 per cent in the base case (Figure 65). ZEV uptake and energy projections are based on separate analysis conducted for the ACT Government by Deloitte. Of the ZEV fleet, 26 per cent by 2045 are assumed to be used as batteries to supply homes (V2H) or the grid (V2G).

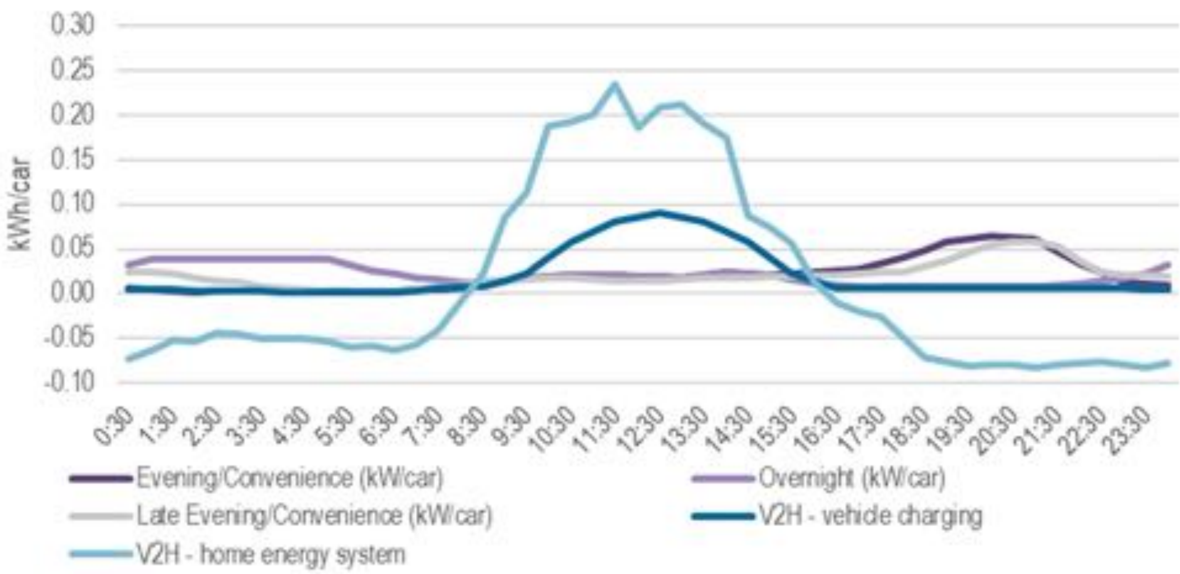
Figure 65 Projected annual energy requirements of passenger ZEV charging (GWh) – Scenario 1 vs base case



Source: Projections obtained from the EPSDD '2021-ACT ZEV Key insights (confidential 'Deloitte report)

In addition to the charging profiles used in the base case (e.g. convenience, overnight, etc.), Scenario 1 incorporates a V2H vehicle charging profile and home energy system charging profile, based on AEMO's latest ISP assumptions. The V2H has two profiles, "vehicle charging" for the purpose of charging the vehicle for transport purposes and "home energy system" that covers the storing and withdrawing of energy in the ZEV for the purposes of managing the household demand. These are shown at Figure 66.

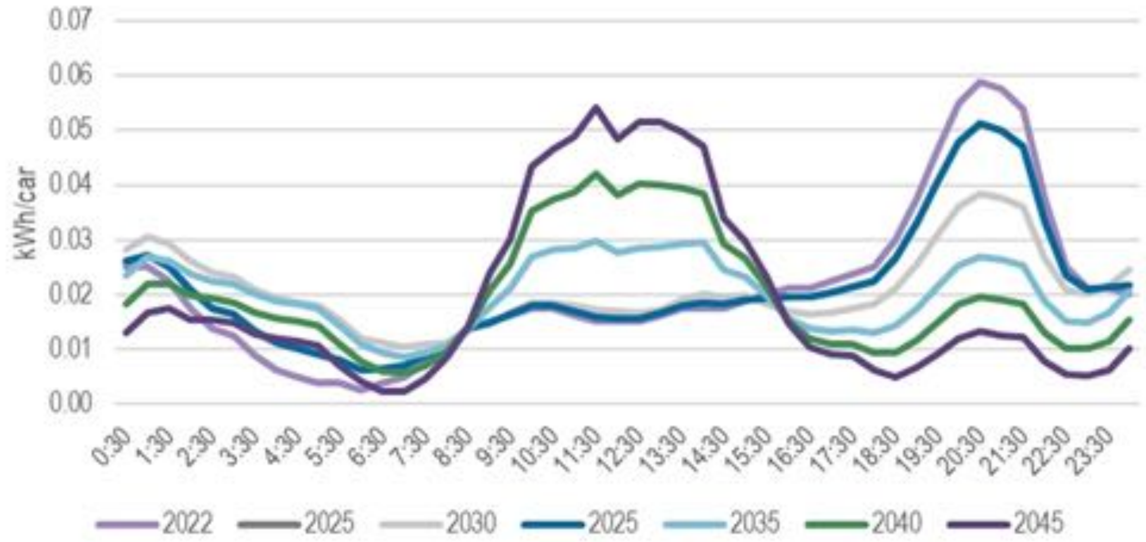
Figure 66 Average time of day ZEV charging profiles (kW/car) – Scenario 1



Source: ACIL Allen analysis of AEMO data

Similar to the base case, 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. As charging infrastructure is further developed and a percentage of ZEVs are used for V2H purposes, 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 (see Figure 67). The daytime peak is much more pronounced in Scenario 1 because of the large charging profile of the V2H home energy system.

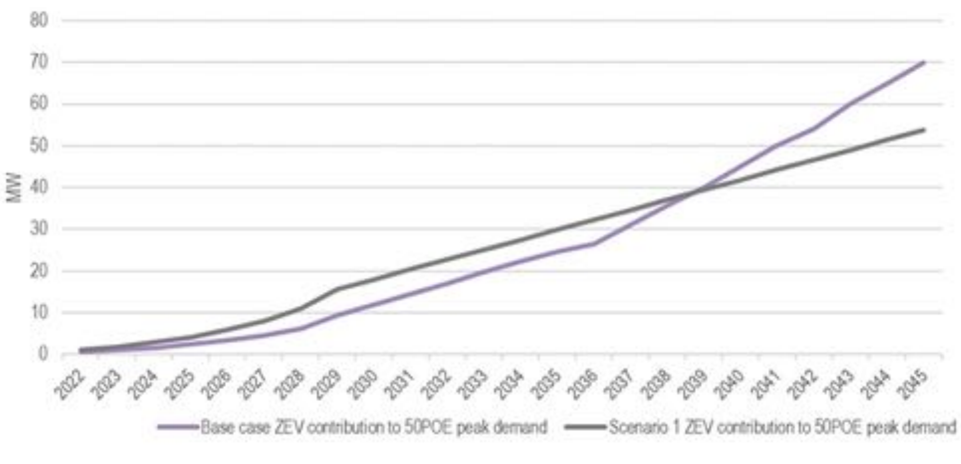
Figure 67 Weighted average combined time of day ZEV charging profile (kW/car) – Scenario 1



Source: ACIL Allen analysis of AEMO data

Figure 68 shows the projected contribution of ZEVs to 50POE peak demand.

Figure 68 Projected contribution of ZEVs to 50POE peak demand (MW) – Scenario 1



Source: ACIL Allen

As discussed earlier, we drew on a combination of AEMO's ISP EV charging profiles to model demand. The charging profiles change shape over time to reflect tariff reform, as well as the use of EVs as battery storage in the home (V2H).[17] The impact on peak demand in the scenarios is less in the later years given these assumptions (increasing EV use as batteries in the home and on the grid (V2G)), which reduces the impact on of EVs on the peak. V2H and V2G uptake is expected to increase with both reform to tariff structures and improved battery technology.

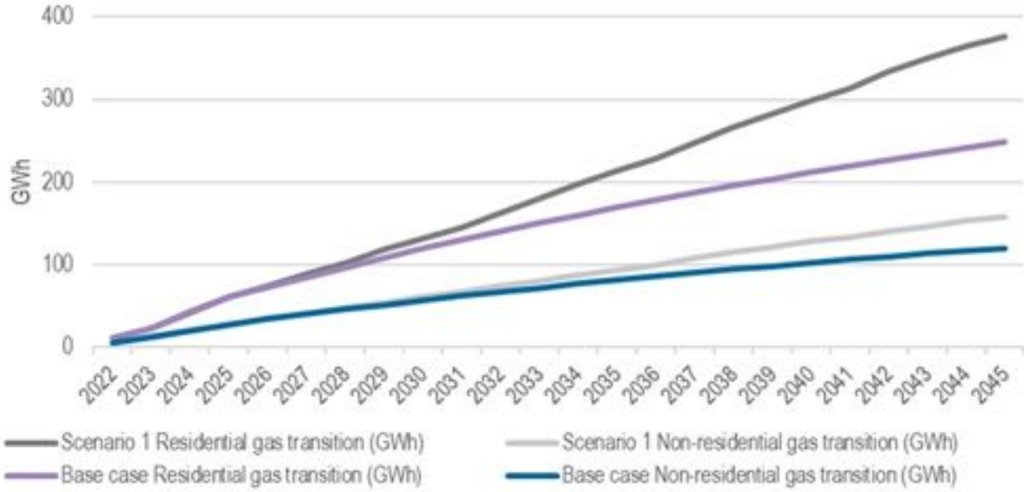
[17] V2H is assumed to ramp up from <1% of EVs in 2030 to 13 per cent by 2045.

6.4.1.4 Electrification

Scenario 1 assumes demand for gas from the gas network reduces by 80 per cent by 2045 (in response to price and cost pressures plus possible Government incentives to transition), compared to 60 per cent by 2045 under the base case. The rate of existing gas customers that switch to electricity each year is assumed 1-2 per cent, compared to 0.85 per cent in the base case. The assumptions around electrification of specific commercial loads including the Canberra Hospital, Molonglo Commercial Centre, CIT Woden, Action bus fleet and Canberra Light Rail stage 2 remain unchanged from the base case. The methodology for converting gas to electricity demand is unchanged from the base case and was described in detail in Section 4.4.

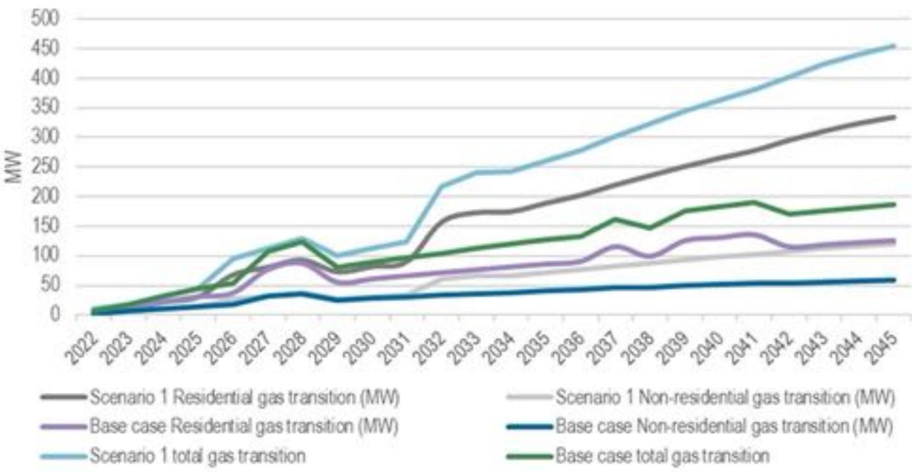
Figure 69 shows projected annual energy requirements from natural gas transition by customer type under Scenario 1 and the base case. Projected winter peak requirements attributed to natural gas transition under Scenario 1 and the base case are shown in Figure 70.

Figure 69 Projected energy requirements from natural gas transition (GWh) – Scenario 1 vs base case



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

Figure 70 Projected contribution to the (winter) 50 POE peak by natural gas transition (MW) – Scenario 1 vs base case



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 flee.

Source: ACIL Allen analysis

6.4.1.5 Final energy and demand

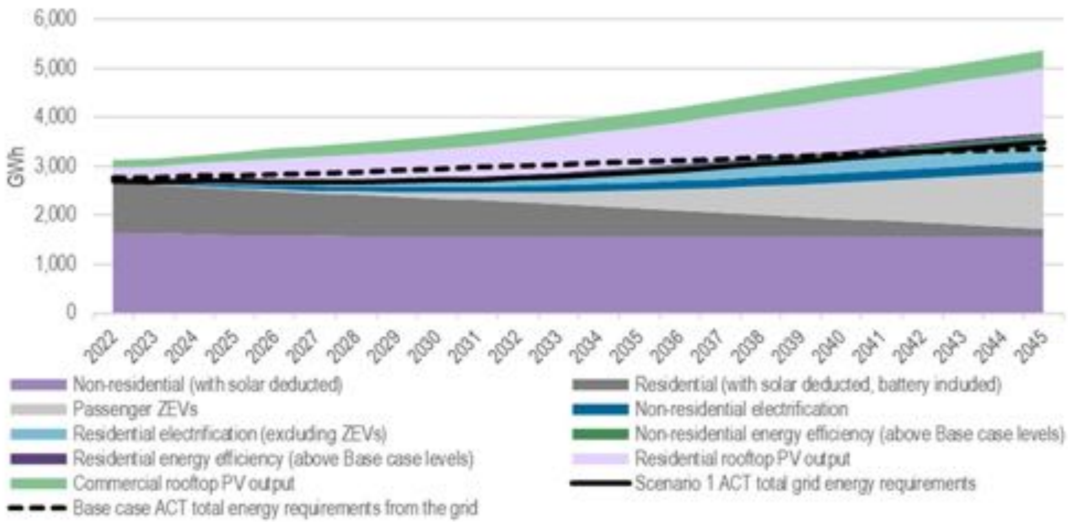
Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, Figure 71 and Figure 72 below show the final assumed annual energy and peak demand projection. ACT total grid energy requirement is projected to grow from 2,772 GWh in 2022 to 3,481 GWh in 2045, which is an increase of around 26 per cent over the projection period, compared to 21 per cent in the base case. ACT 50POE peak grid demand is projected to grow from 654 MW in 2022 to 1,106 MW in 2045, which is an increase of around 70 per cent over the projection period, compared to 48 per cent in the base case.

The growth in peak demand is predominantly driven by electrification of space heating requirements during winter mornings. Home batteries are assumed to charge during the middle of the day and discharge during the evening peak (including electrification of space heating requirements during winter evenings). V2H batteries discharge to meet some of the morning space heating requirements.

Key factors encompassed in this outcome (an increase of around 26 per cent over the projection period) include:

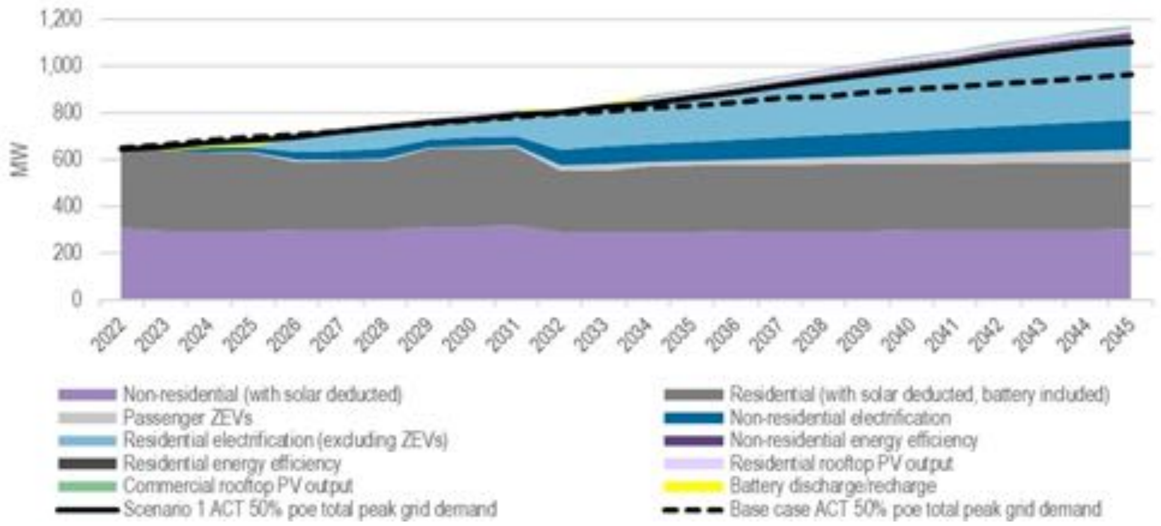
- delivery of 33 per cent of total energy requirements through rooftop PV by 2045
- ZEVs comprise 68 per cent of car fleet by 2045 (producing no emissions, but adding to electricity demand)
- the continued hollowing out of the demand profile across daylight hours because of rooftop PV, and a growth in demand during the evening because of electrification
- the impact of behind-the-meter storage on the demand profile is reasonably small given the level of uptake projected
- taking out 20 per cent more gas consumption (from 60 per cent by 2045 in the base case to 80 per cent by 2045 in Scenario 1) only increases electricity energy requirements by 166 GWh in 2045 or five per cent of total grid energy requirements in 2045 taking out 20 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 268 MW by 2045 or 25 per cent of total peak demand by 2045.

Figure 71 Projected energy requirements (GWh) – by category – Scenario 1 vs base case



Note: V2H is included in Passenger ZEVs. 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 72 Projected 50 POE peak demand (MW) – by category – Scenario 1 vs base case



Note: V2H is included in Passenger ZEVs. 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

6.4.1.6 Average time of day demand

The projected higher uptake of rooftop PV installations, storage, and electrification in Scenario 1 will continue to change the shape of the time-of-day profile of demand in the ACT, resulting in lower average time of day demands during daylight hours compared to the base case.

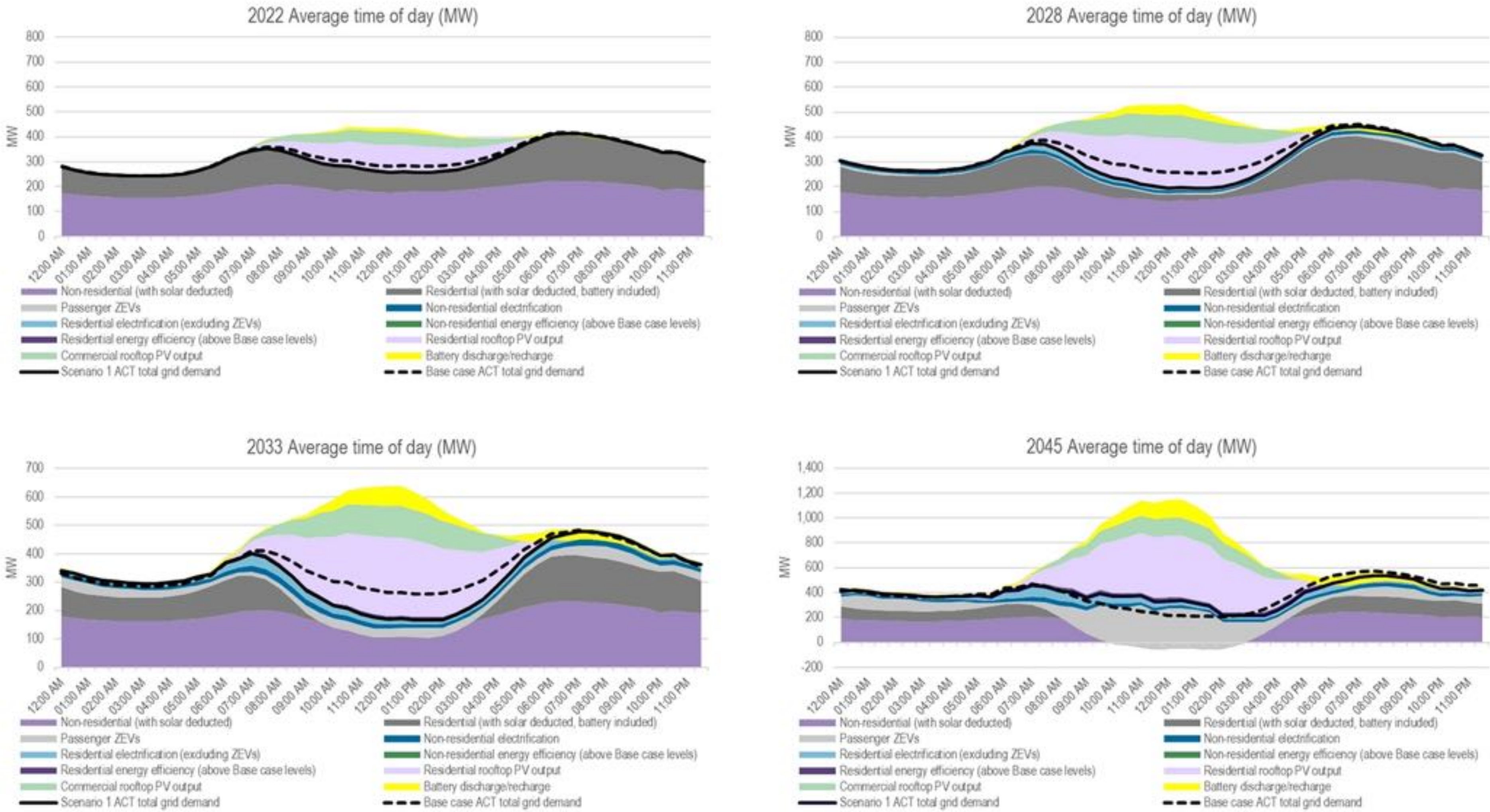
Figure 73 illustrates the impact of these technologies on the average time of day operational demand profile for 2022, 2028, 2033 and 2045.[18]

Similar to the base case, the graphs show the continuation of the hollowing out of the demand profile across daylight hours because of rooftop PV, and a growth in demand during the evening because of electrification.

By 2045, the assumed use of V2H[19] (included in the ‘passenger EV’ series) during the middle of the day has increased average time of day demand during these hours compared to the base case. By comparison, the impact of home storage (represented in the ‘battery discharge/recharge’ series) on the demand profile is reasonably small given the level of uptake projected, although it is slightly higher than the base case.

[18] The mid-point dates (2028 and 2033) are selected to align with Evoenergy’s regulator review periods.
[19] The use of V2H is assumed to ramp up gradually from <1 per cent of EVs in 2030 to around 13 per cent of EVs by 2045.

Figure 73 Average time of day demand (MW) – for selected years



Note: V2H is included in Passenger ZEVs
Source: ACIL Allen

6.5 Electricity system network analysis

6.5.1 Power modelling

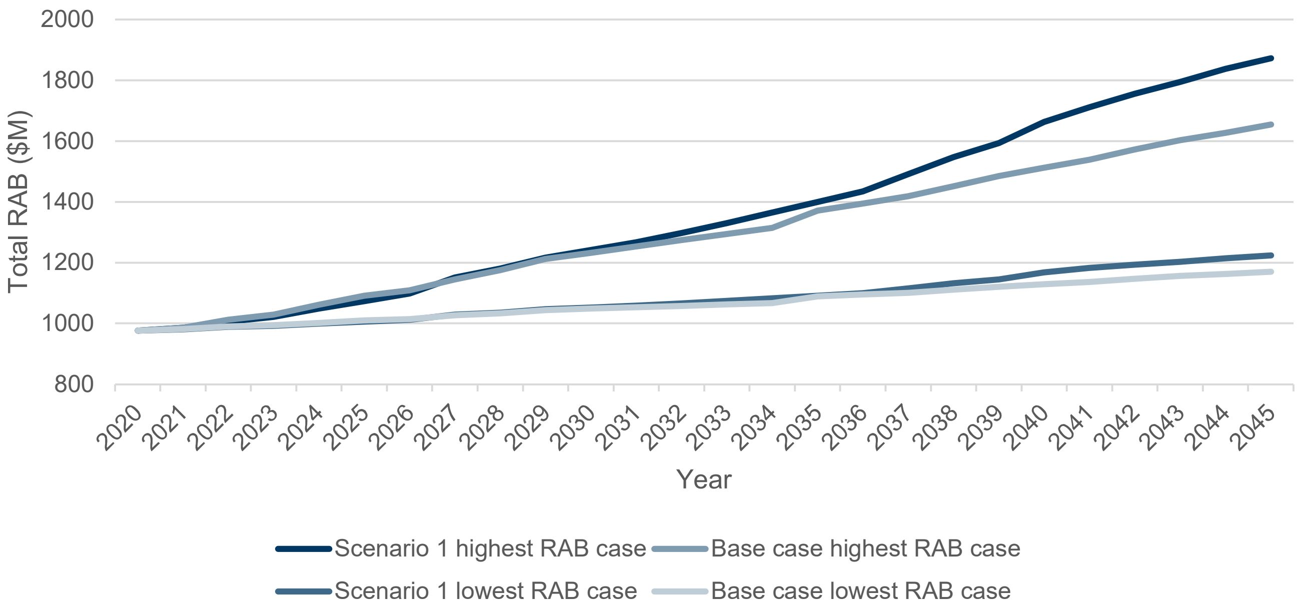
Power modelling has been performed to identify and quantify future levels of investment into the Evoenergy electricity network to aid in identifying the cost that would be passed onto energy consumers to maintain the network to current levels of safety, security and reliability.

The modelling in all scenarios has been completed using the methodology provided in Section 3.3.

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 74 the range of the RAB between the most extreme cases is shown. All other modelling only considers the worst-case (highest) scenario RAB.

Figure 74 Comparison of highest and lowest possible RAB outcomes in Scenario 1



Source: GHD

The results of the modelling show that the total increase in the RAB over the period 2020-2045 is approximately $896 million as opposed to the increase in RAB over the same time in the base case of $678 million.

Figure 75 shows the change in the RAB by type of investment in the Scenario 1 forecast (refer Section 4.3 for detailed description of investment types).

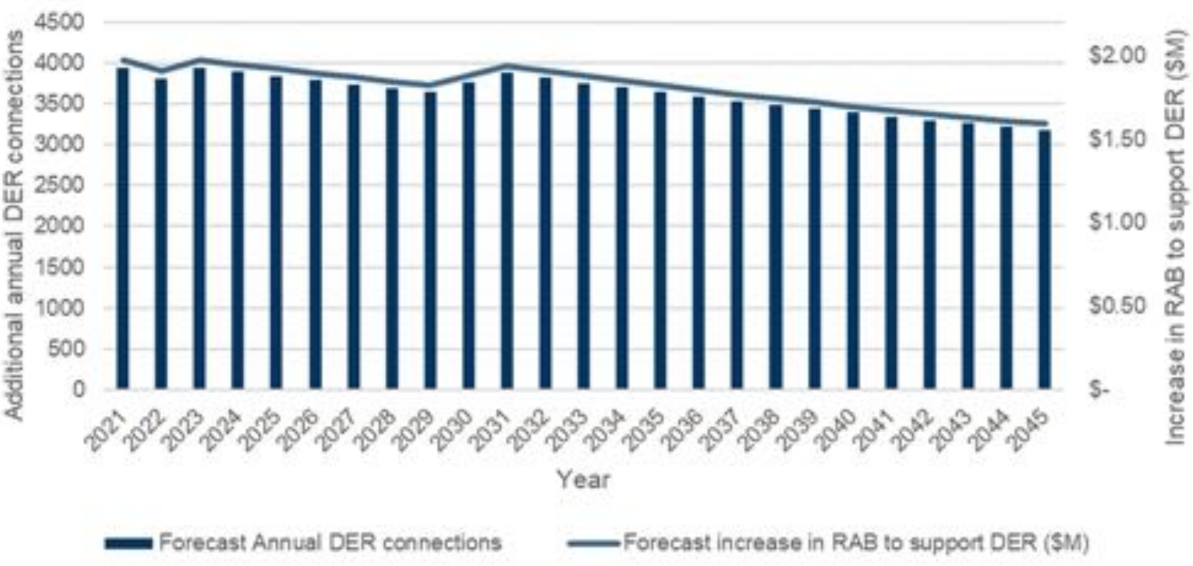
Figure 75 Cumulative change in RAB in Scenario 1 by investment type

Source: GHD

Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests).

Compared to the base case there is an increase in location specific projects from 20 projects totalling $154 million up to 29 projects totalling $228 million (these figures include projects already underway). The detailed list of projects identified as required in Scenario 1 is shown in The increased uptake of DER and associated investment required to maintain quality of supply to customers is shown in Figure 76.

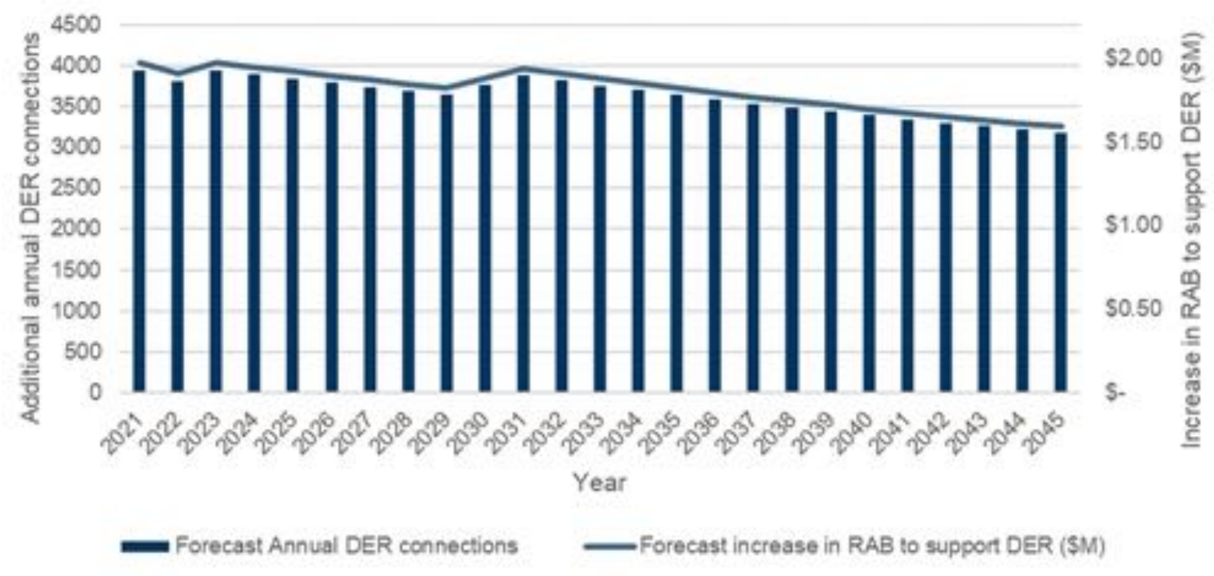
Figure 76 Additional DER and associated network investment forecast in Scenario 1



Source: GHD

Table 10. The increased uptake of DER and associated investment required to maintain quality of supply to customers is shown in Figure 76.

Figure 76 Additional DER and associated network investment forecast in Scenario 1



Source: GHD

Table 10 Forecast specific investments required in Scenario 1

KEY

+ = new or larger
↑ = moved forward
↓ = later date
x = no change

Year	Change from base case	Investment(s)	Estimated cost ($ million)
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
2028	↓	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
2034	↑	Construct 1 new distribution feeder out from East Lake Zone substation	2.9
2037	↓ ✕	Construct 3rd Transformer at East Lake Zone substation Construct 2 new distribution feeder out from East Lake Zone substation	12.0
2038	✕ ✕ +	Construct 1 new distribution feeder out from East Lake Zone substation Construct 2 new distribution feeder out from City East Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	14.5
2039	✕	Construct 2 new distribution feeder out from Civic Zone substation	5.8
2040	↑ ✕ ↑ ✕ ↑ ↓	Construct 3rd Transformer at Belconnen Zone substation Construct 1 new distribution feeder out from East Lake Zone substation Construct 2 new distribution feeder out from Belconnen Zone substation Construct 2 new distribution feeder out from City East Zone substation Construct 2 new distribution feeder out from Latham Zone substation Construct 2 new distribution feeder out from Telopea Park Zone substation to transfer load to East Lake	32.3
2041	↑ ↑	Build new sub transmission line between Canberra Terminal Station and Latham zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	12.8

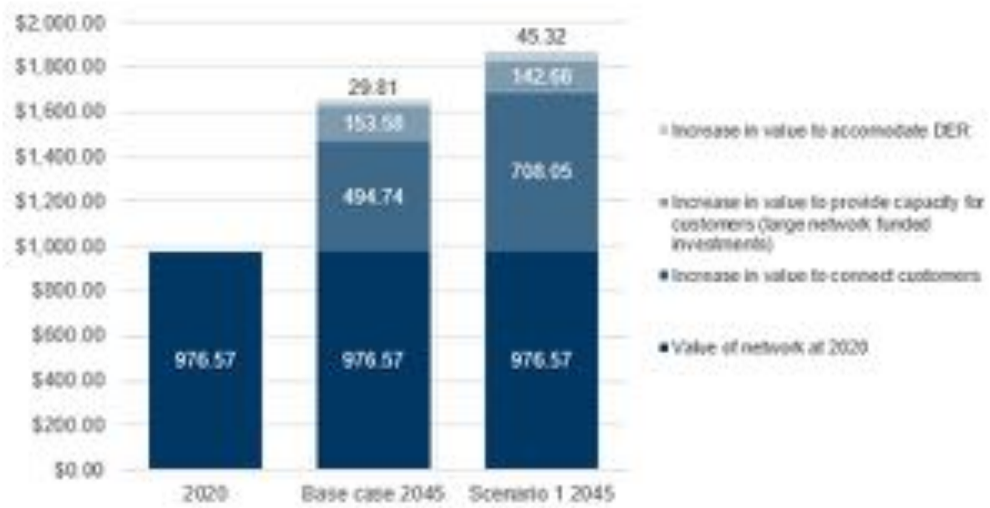
Year	Change from base case	Investment(s)	Estimated cost ($ million)
2042	↓	Establish new zone substation (ZS1) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Woden and Molonglo	85.6
	+	Establish new zone substation (ZS2) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Civic, City East, East Lake and Telopea Park	
	↑	Construct 1 new distribution feeder out from East Lake Zone substation	
	+	Construct 1 new distribution feeder out from Theodore Zone substation	
	×	Construct 2 new distribution feeder out from Belconnen Zone substation	
	×	Construct 2 new distribution feeder out from Civic Zone substation	
	×	Construct 2 new distribution feeder out from Latham substation	
2044	+	Construct 1 new distribution feeder out from East Lake Zone substation	8.7
	+	Construct 2 new distribution feeder out from Gold Creek Zone substation	
2045	+	Construct 2 new distribution feeder out from Civic Zone substation	5.8

Source: GHD

6.5.2 Impact on network investment

The Scenario 1 demand forecast will require investment of an additional $896 million in the network to (increasing the RAB valuation from $976.57 million in 2020 to $1,872 million in 2045). The relative magnitude of the growth in the various segments of the network are shown in Figure 77 below compared to the same period in the base case.

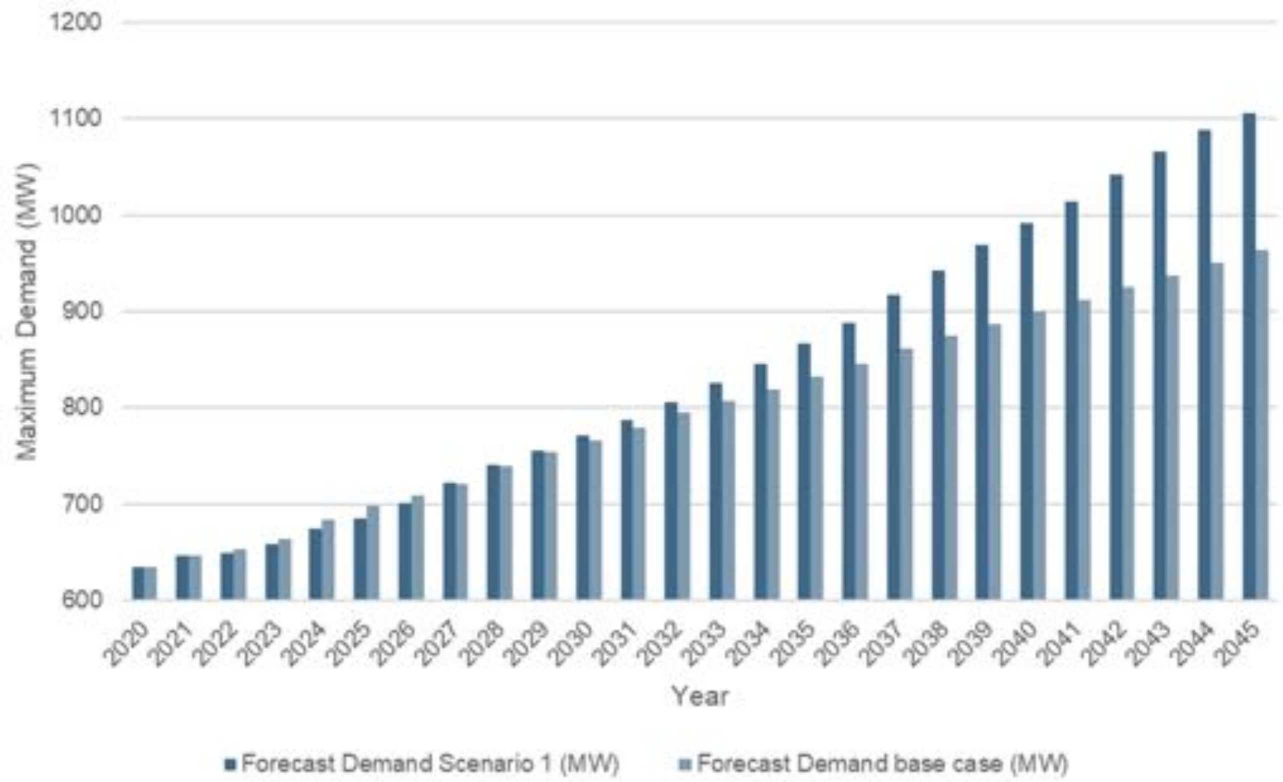
Figure 77 Change in value of the distribution asset base 2020-2045, $ million



Source: GHD

The main changes in Scenario 1 compared to the base case relate to a slower growth in demand out to 2027 when the Scenario 1 demand growth then starts to exceed the base case and drive increased investment. The rate of growth in demand starts to really accelerate particularly in the winter from 2033 onwards leading to a 100MW difference in demand by 2045 as shown in Figure 78. The main driver for the growth beyond 2033 is the transition away from gas heating in existing houses at a faster rate than in the base case (up to double the rate of transition).

Figure 78 Change in network demand between Scenario 1 and base case



Source: GHD

The changed growth in demand impacts on the projects required by slowing initial investment in the RAB up to 2025-26 and with investment in the RAB increasing significantly from 2027 onwards, as shown in Figure 79.

Most of the investment in this scenario is in the areas where high populations already exist (Civic, City East, East Lakes, Latham and Telopea Park) and areas where population growth is forecast (Belconnen, Gold Creek, Molonglo and Woden).

The areas where the high population already exists have large investment due to the gradual build-up of people transitioning to gas late and the moderate population growth in these areas.

The areas with high population growth have investments more driven by the increase in population as the transition to gas effects a smaller pool of customers in these areas.

The increased uptake of solar and batteries does help keep the demand in check which delays demand related investments but does increase investment in measures to maintain supply quality.

Overall, the roughly $15 million additional spend over the entire Scenario 1 compared to the base case on maintaining supply quality due to DER has likely paid for itself in project deferrals. For example, the change in the establishment of ZS1 (at $32 million investment) being deferred from 2035 in the base case to 2042 in Scenario 1.

Figure 79 Change in annual increase in RAB between Scenario 1 and the base case

Source: GHD

6.5.3 Constraints

The only real constraint identified in each of the scenarios and base case modelled is how much capital can be made available to maintain existing levels of safety, security and reliability for the forecast change in demand in the network. That being said, in Scenario 1 an additional zone substation was identified as being required to help offload the Civic, City East, East Lake and Telopea Park areas.

All of these locations are reasonably well-developed parts of the ACT which may make it difficult to identify a suitable location both in terms of land for a new substation but also in terms of being able to establish new lines in locations where lines already exist. This type of constraint could result in significant increases in expenditure beyond that which has been forecast for the project if the location of the substation ends up in a difficult location to connect.

6.6 Electricity retail bill impacts

6.6.1 Wholesale component

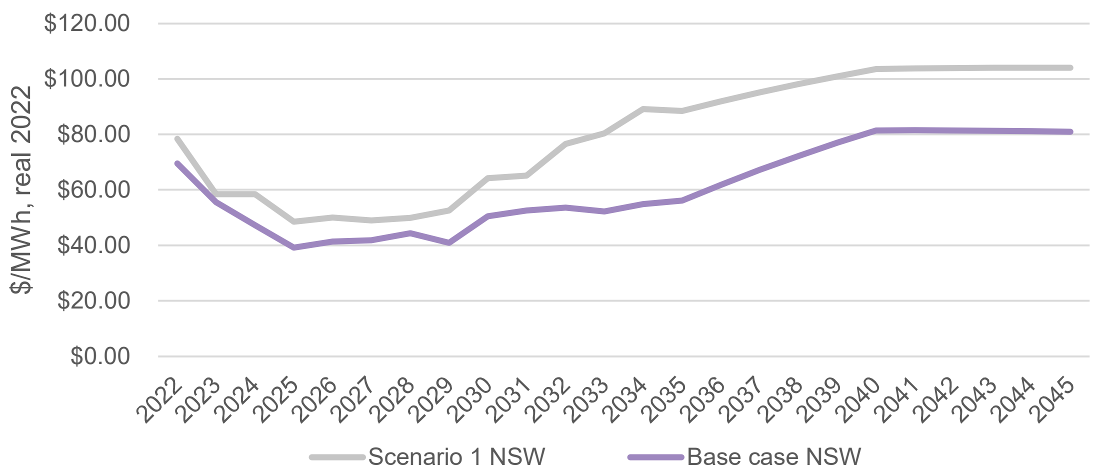
Similar to the base case, *PowerMark* projected wholesale prices in the New South Wales (NSW) NEM region have been used to estimate the Scenario 1 wholesale cost component of the retail bill. In Scenario 1 we have used our December 2021 Reference case as a basis for estimating wholesale costs.

This Reference case uses the AEMO's draft 2022 ISP "strong electrification" demand scenario, which is a higher demand scenario than the "net zero by 2050" demand scenario used in the base case. The resulting projected time-weighted spot prices for the NSW region are shown in Figure 80 and compared to the base case.

In the short- to medium-term, projected prices are higher than the base case due to higher demand from electrification. In the long-run, projected prices are also higher than the base case due to higher costs of generation. From 2040 onwards all gas-fired generators are assumed to transition to green hydrogen. The cost of hydrogen is significantly higher than natural gas (by 2040 assumed hydrogen costs 20$/GJ versus gas at 11$/GJ).

In addition, the increase in demand, along with the closure of coal-fired generation plants, requires substantially more additional investment when compared with the base case. This requires development of generation projects in areas with a poorer renewable energy resource and/or network location – resulting in higher marginal cost of energy and hence higher long term price outcomes.

Figure 80 Projected time weighted prices for NSW region ($/MWh, real 2020) – Scenario 1 vs base case



Source: ACIL Allen

6.6.2 Network component

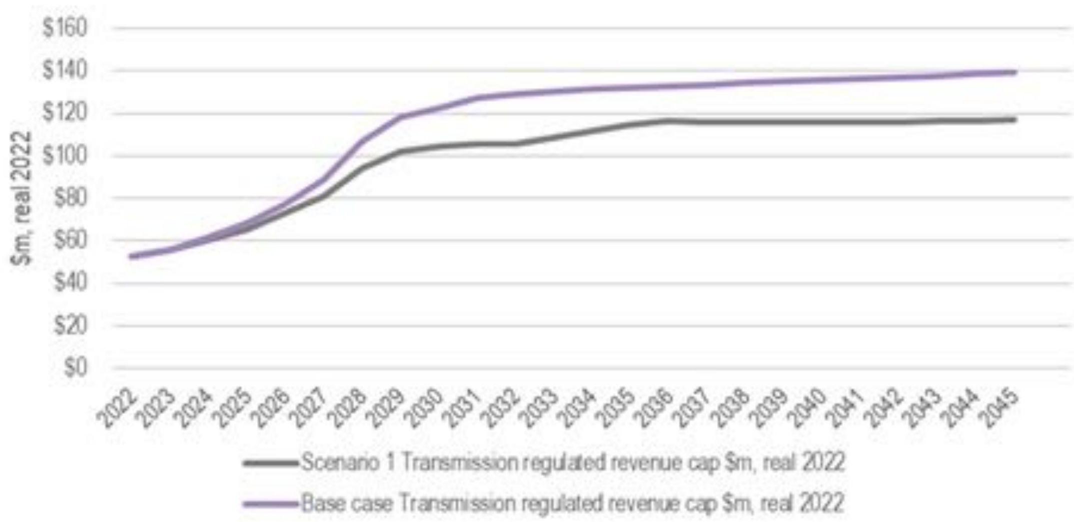
Similar to the base case, ACIL Allen has projected annual regulated revenues based on the building blocks method. Network Use of System (NUOS) tariffs by customer type have been estimated using the expected weighted average revenue for the regulatory year 2021-22 in Evoenergy's pricing proposal and projected forward based on these weightings.

6.6.2.1 Transmission

Figure 81 below shows projected annual revenues recovered by Evoenergy through Transmission Network Use of System (TUOS) tariffs. Projected TUOS revenues assume significant capital expenditure by TransGrid (transmission network company for the broader NSW) region for network augmentation under Scenario 1 associated with the ISP actionable projects and significant investment in new generation from electrification under Scenario 1.

Projected revenues for the ACT TUOS component are allocated using the proportion of ACT electricity consumption relative to NSW electricity consumption. Despite increased projected network augmentation of the TransGrid network under Scenario 1 compared to the base case, projected revenues apportioned to ACT customers under Scenario 1 are lower than the base case because the increase in electricity consumption across NSW (due to higher electrification) is proportionally higher than the increase in consumption in the ACT under Scenario 1. That is, the higher transmission spending required in Scenario 1 is smeared across a large consumption base in NSW.

Figure 81 ***Projected annual revenues for transmission ($ million, real 2022) – Scenario 1 vs base case***

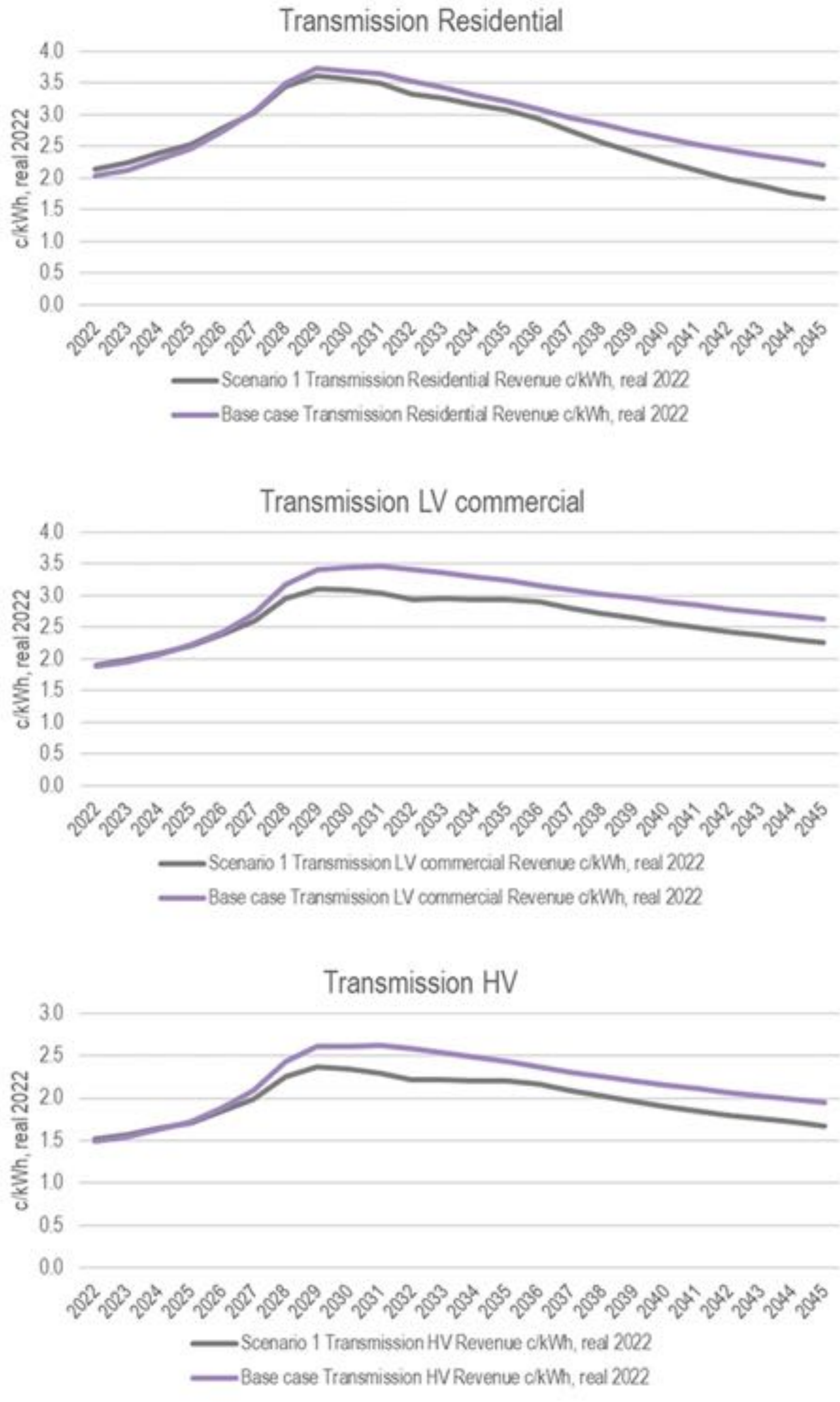


Source: AER, TransGrid, Evoenergy, ACIL Allen

Projected TUOS tariffs by customer type are shown in Figure 82 below. Similar to the base case, projected TUOS tariffs in Scenario 1 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.

The rate of decline in residential TUOS tariffs is higher from around 2040 due to the impact of higher residential consumption from passenger ZEVs in Scenario 1.

Figure 82 Projected TUOS tariff, by customer type (c/kWh, real 2022) – Scenario 1 vs base case



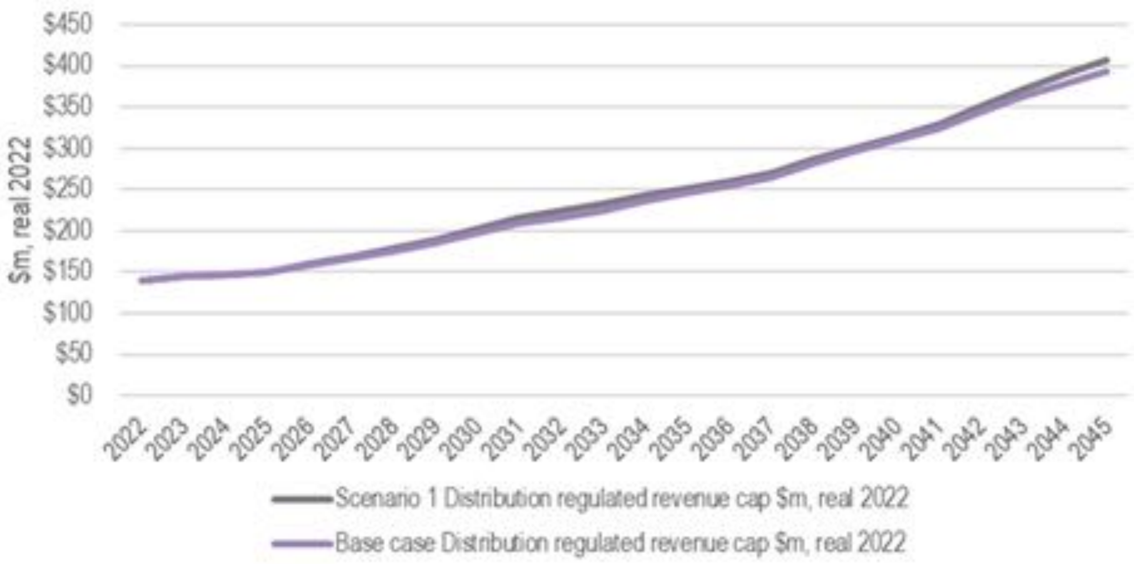
Source: AER, Evoenergy, ACIL Allen

6.6.2.2 Distribution

Similar to the base case, 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 Section 6.5) into this analysis.

Figure 83 shows projected annual revenues recovered by Evoenergy through Distribution Network Use of System (DUOS) tariffs. From around 2025, Scenario 1 projected revenues are higher than the base case by between two and four per cent per annum, reflecting greater network spend in Scenario 1.

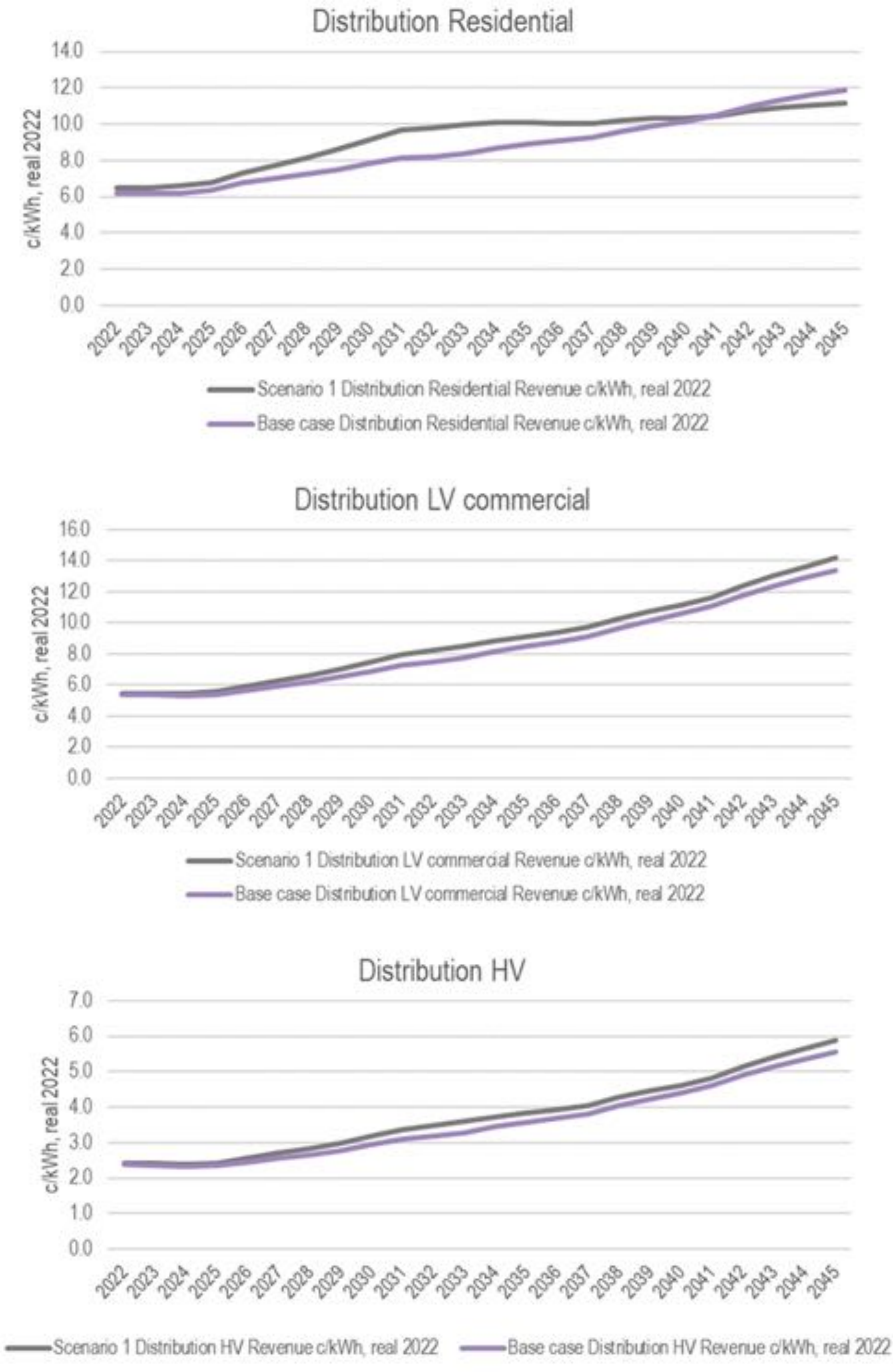
Figure 83 Projected annual revenues for distribution ($ million, real 2022) – Scenario 1 vs base case



Source: AER, Evoenergy, ACIL Allen

Projected DUOS tariffs by customer type are shown in Figure 84. Like the base case, projected DUOS tariffs in Scenario 1 increase in real terms in line with total revenue growth. However, from around 2030, residential DUOS tariff growth slows due to higher ZEV uptake in Scenario 1. That is, DUOS revenue is spread across a larger consumption base (due to higher uptake of ZEVs adding to energy requirements) from 2030.

Figure 84 Projected DUOS tariff, by customer type (c/kWh, real 2022) – Scenario 1 vs base case



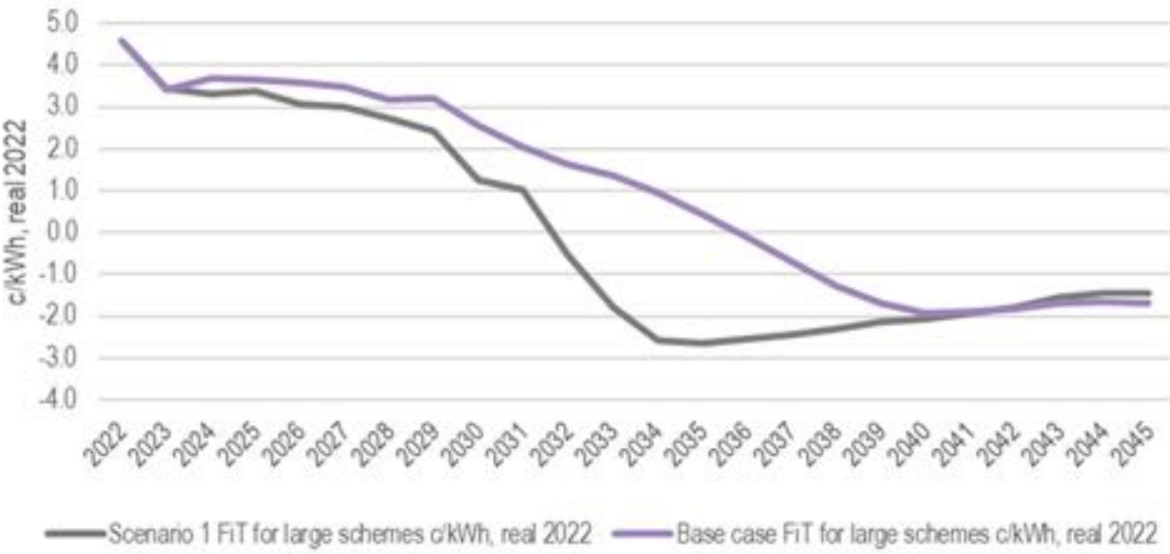
Source: AER, Evoenergy, ACIL Allen

6.6.2.3 Jurisdictional schemes

Similar to the base case, projected hourly wholesale electricity spot prices in NEM regions NSW, Victoria and South Australia from *PowerMark* have been used to calculate large feed-in tariff (FiT) payments in relation to projecting the impact of ACT continuing to purchase 100 per cent renewable electricity. Projected large FiT payments are shown in the chart below and compared to the base case. We have assumed no change to the auction wind farms - they have the same installed capacity, timing, and contract price. The lower payments under Scenario 1 are largely the result of higher projected price wholesale electricity spot prices.

Over the period to 2029, projected large FiT payments remain at current high levels, given projected wholesale prices are expected to continue to decline as the result of significant amounts of new supply entering the market.[20] From around 2029, projected wholesale electricity prices rise with the closure of several major coal fired power stations and growth in demand from projected electrification, including ZEV uptake, which results in projected large FiT payments declining. As indicated in Figure 85, large FiT payments are projected to continue to decline and by around 2032 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.

Figure 85 Projected large feed in tariff payments (c/kWh, real 2022) – Scenario 1 vs base case



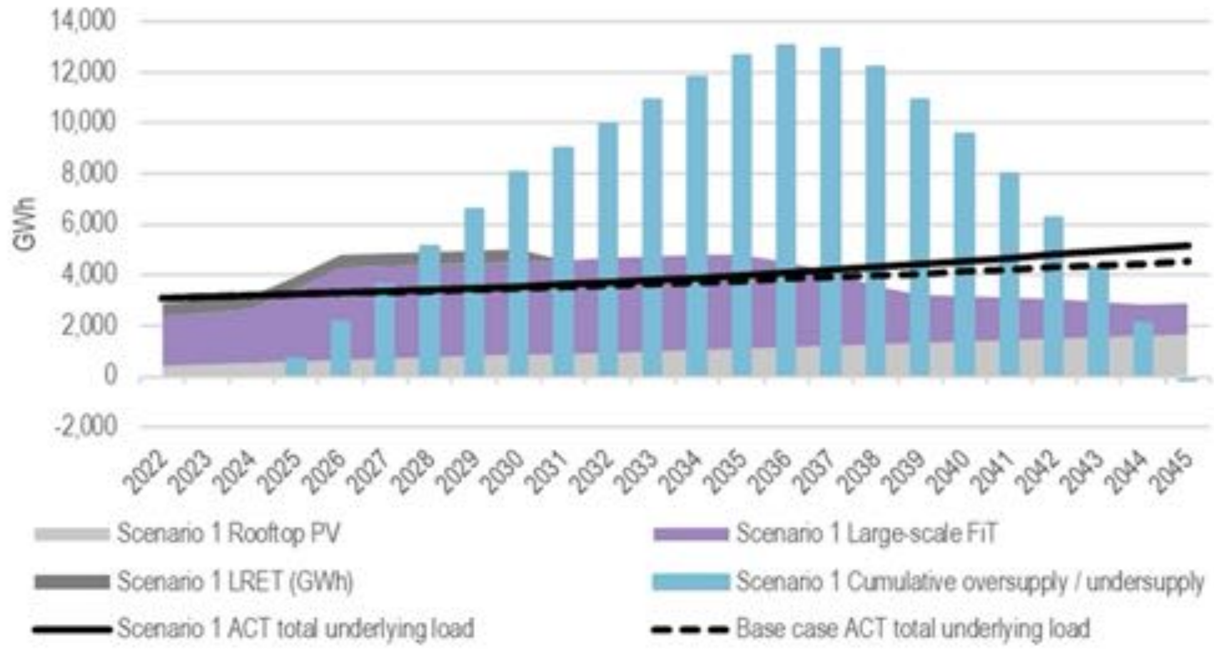
Note: FY2022 estimate is Evoenergy's estimate published in their 2021-22 pricing proposal.
Source: ACIL Allen analysis based on the median or 50th percentile view, https://www.environment.act.gov.au/energy/cleaner-energy/renewable-electricity-costs-and-reviews, and Evoenergy Pricing Proposal 2021-22

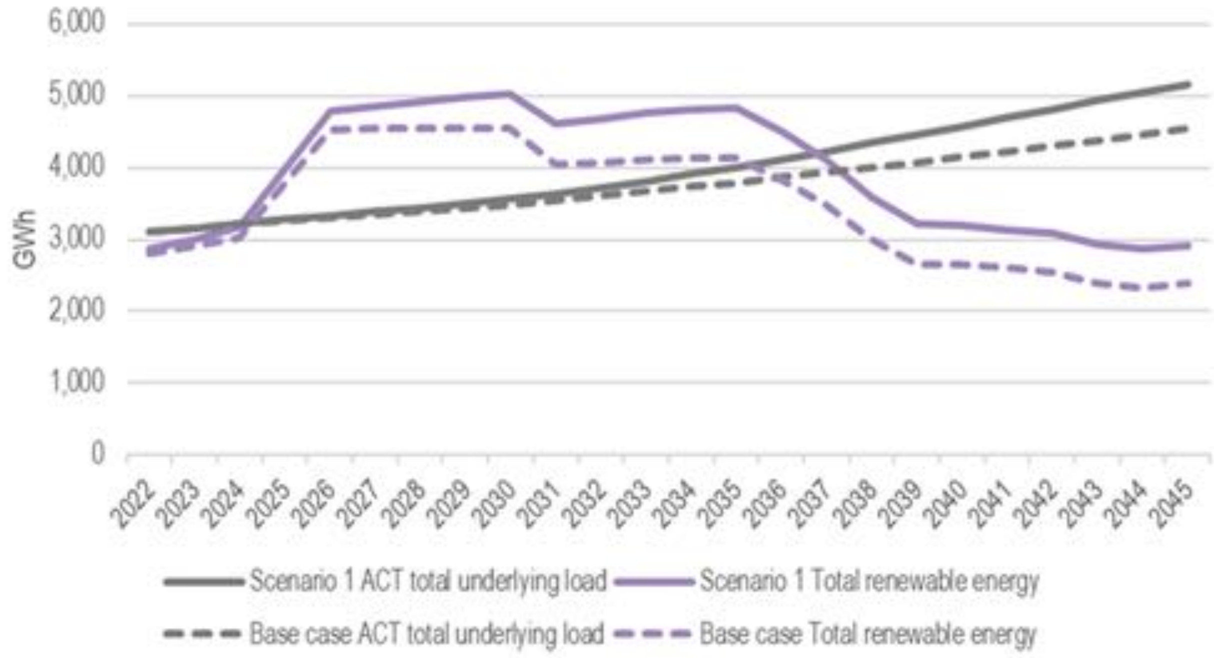
Similar to the base case, Scenario 1 incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable. The projections show that the ACT will fall below the 100 per cent renewable mark from 2037, declining to around 57 per cent of underlying demand by 2045 as shown in Figure 86 (top figure). Based on the figure, the government could need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is 'banked'

[20] Assumed new supply from large-scale grid renewable supply proposed by state-based schemes such as the NSW Roadmap and also from behind-the-meter generation.

with credits carrying over to future years. These 'banked' credits are carried forward and built into the cumulative oversupply/undersupply blue bars at the first figure below. These credits offset the need for additional purchases up until 2045. The second figure below shows that Scenario 1 has more renewable supply in GWh terms than the base case and this more than offsets the higher underlying demand in Scenario 1. As discussed above, we have assumed no change to the auction wind farms. The difference lies in how the wind farms are dispatched in Scenario 1. Due to significantly higher demands across the NEM from electrification, the auction wind farms experience lower levels of curtailment than in the base case (or higher dispatch) and therefore more supply in GWh towards the target.

Figure 86 *Projected contribution by category to 100% renewable energy (GWh) – Scenario 1 vs base case*





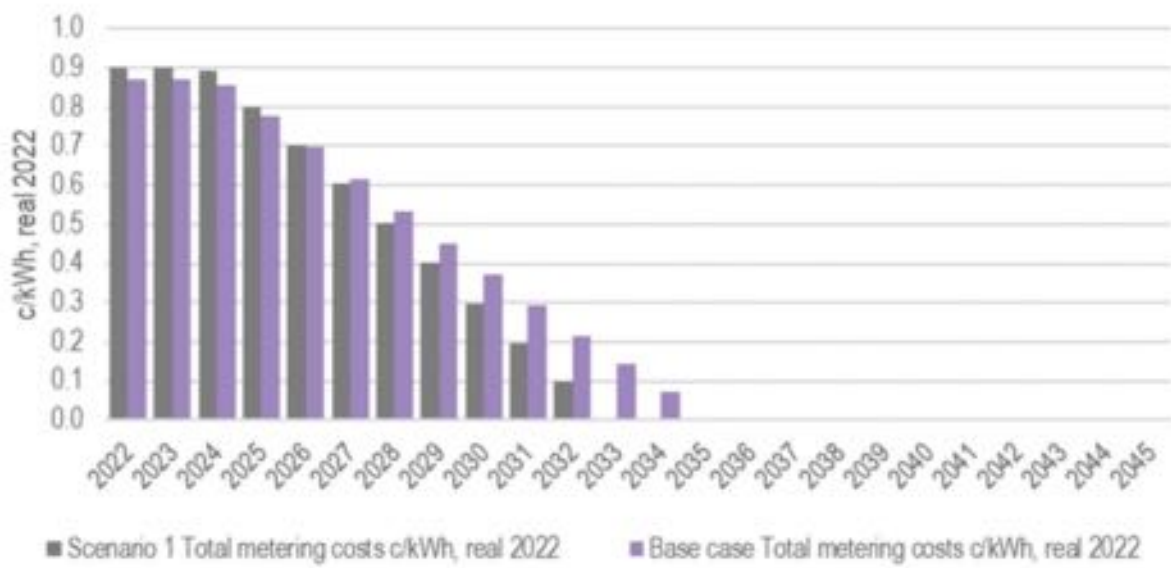
Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis

6.6.2.4 Metering

Regulated metering charges cover the costs associated with Evoenergy's provision of regulated Type 5 and Type 6 metering services.[21] The projections illustrated at Figure 87 assume that Type 5 and Type 6 meters are phased out completely by 2033 under Scenario 1, which is earlier than the base case.

From around 2027, regulated metering costs are lower than the base case as a result of higher assumed rooftop solar and battery uptake and general faster adoption of smart meters by residential and low voltage commercial customers in Scenario 1.

Figure 87 Projected metering costs (c/kWh, real 2022) – Scenario 1 vs base case



Source: ACIL Allen, AER, Evoenergy

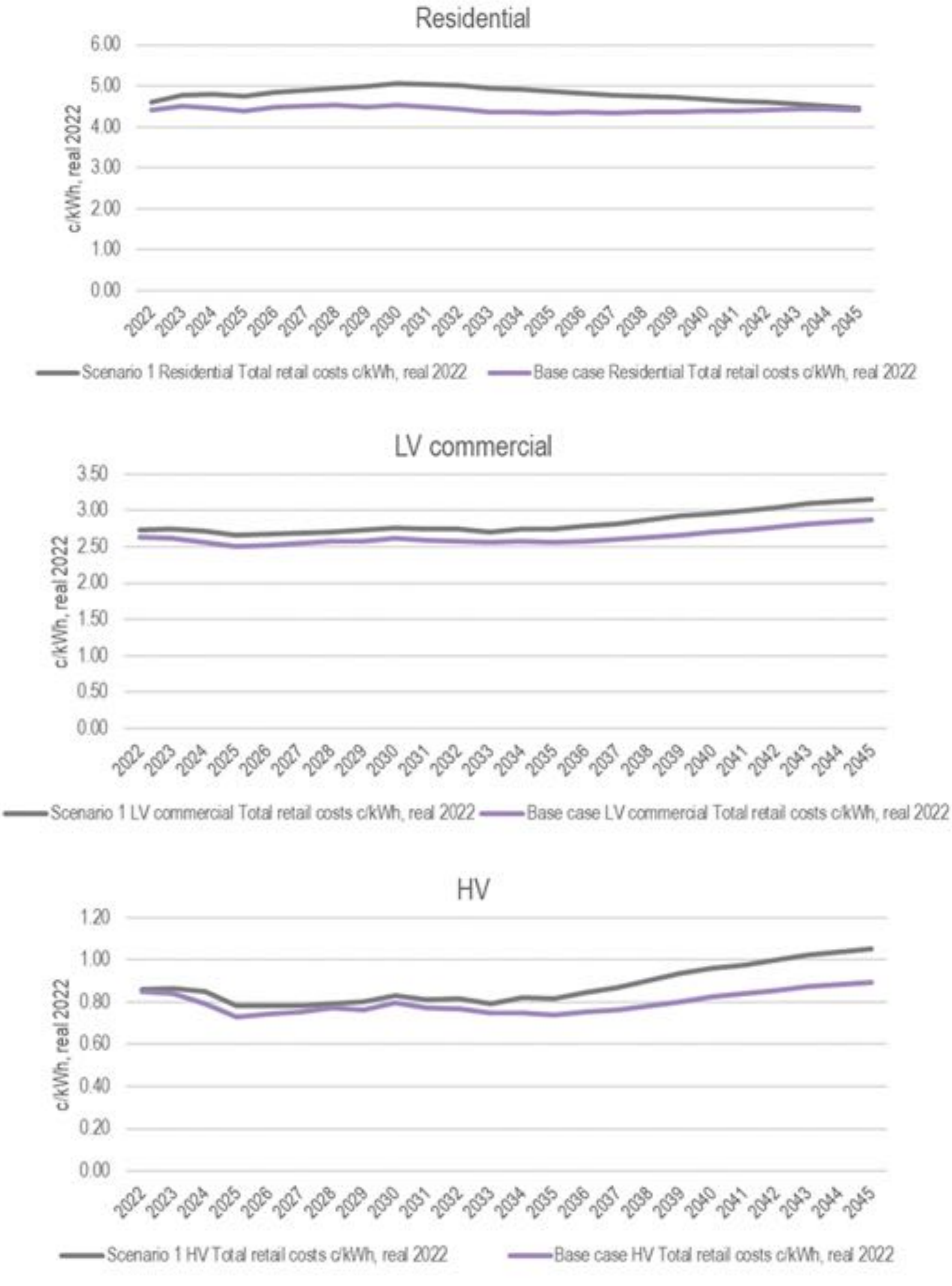
6.6.3 Retail component

Scenario 1 projected total retail costs are generally higher than the base case, as illustrated at Figure 88, due to higher assumed smart meter costs (residential and LV customers only), higher energy efficiency scheme costs (residential and LV customers only), and higher retailer margin (in dollar terms) (all customers).

While consumption initially decreases in this scenario, projected demand from EV charging results in energy requirements rising from around 2030 (as shown in Section 6.4.1.5), which offsets the higher costs for residential customers in Scenario 1.

[21] Smart metering costs are factored into the retail cost component.

Figure 88 Projected cost of retail component, by customer type (c/kWh, real 2022) – Scenario 1 vs base case



Source: ICRC, ACIL Allen

6.6.4 Total retail prices

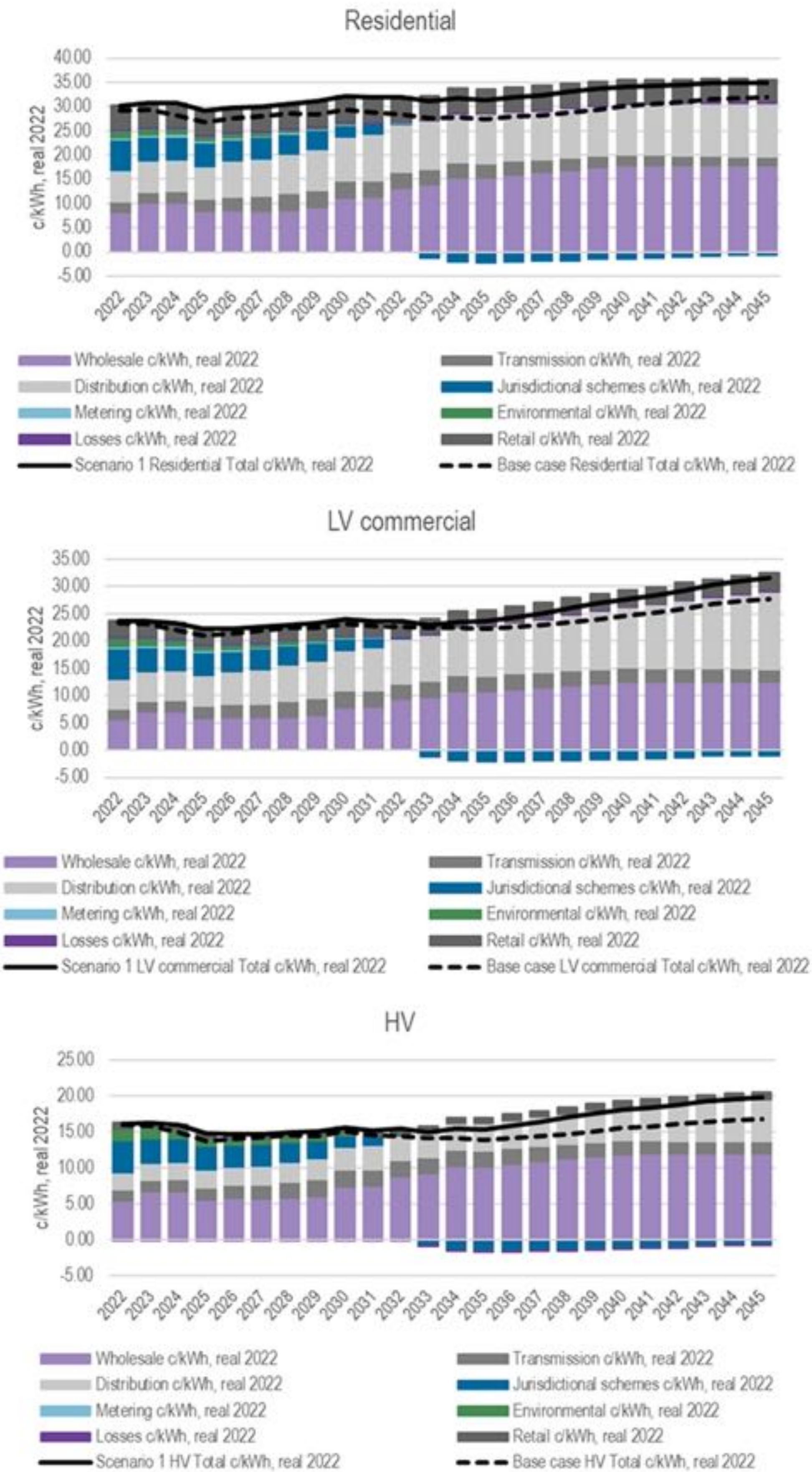
Bringing together the wholesale, network and retail components discussed in this Chapter, the projected retail prices are shown in Figure 89.

In Scenario 1, real retail prices for residential, LV commercial and HV customers are projected to increase by 16 per cent, 33 per cent and 22 per cent respectively over the period from 2022 to 2045. Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large FiT payments over the period.

The projections by component are as follows:

- Wholesale component – is projected to remain at current low levels until around 2029 given the significant amount of new large-scale grid supply assumed to enter the market under state-based schemes and also due to an increase in supply from behind-the-meter solar generation. From 2030, the projected wholesale component rises, reflecting the closure of several major coal fired power stations and growth in demand from projected electrification, including ZEV uptake. From around 2040, projected wholesale prices are capped at the long-run cost of new entrant supply.
- Network component (transmission) – is projected to rise over the period to 2030 because of projected capital expenditure to support major transmission network augmentations in combination with modest growth in consumption. After 2030, accelerated consumption growth is projected to surpass network revenue growth, resulting in a declining transmission component.
- Network component (distribution) – is projected to rise over the entire period because of projected capital expenditure to support major distribution network augmentations. After 2030, accelerated consumption growth due to ZEV uptake is projected to slow the growth in the distribution component for residential customers.
- 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 around 2032, the large FiT is expected to return net revenues to customers.
- Network component (metering) – is projected to decline over the period to 2033 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.
- Retailer component – for residential customers, this component is projected to be stable over the period to 2035, and then decline as projected average consumption per customer increases. For high voltage customer, retail costs increase in line with the increase in other tariff components, given retail costs for these customers are comprised entirely of the retailer margin.

Figure 89 **Projected retail prices in the ACT, by component, by customer type (c/kWh, real 2022) – Scenario 1 vs base case**



Source: ACIL Allen

6.6.5 Retail bill

We have estimated projected retail bills for different customers as shown in Figure 90 below by multiplying the projected retail price by the projected average consumption per customer.[22]

- projected average consumption per customer declines over the period to around 2031 because of the projected increase in penetration of rooftop solar PV
- after 2031, projected average consumption per residential customer rises as a result of electrification
    - for LV and HV commercial customers, projected average consumption rises from 2030 and 2026, respectively as a result of the impact of natural gas transition.

Over the period to 2030, projected retail bills for residential, LV commercial and HV customers are relatively constant, in real terms. This is the result of the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes offsetting projected increase in wholesale and distribution/transmission network costs.

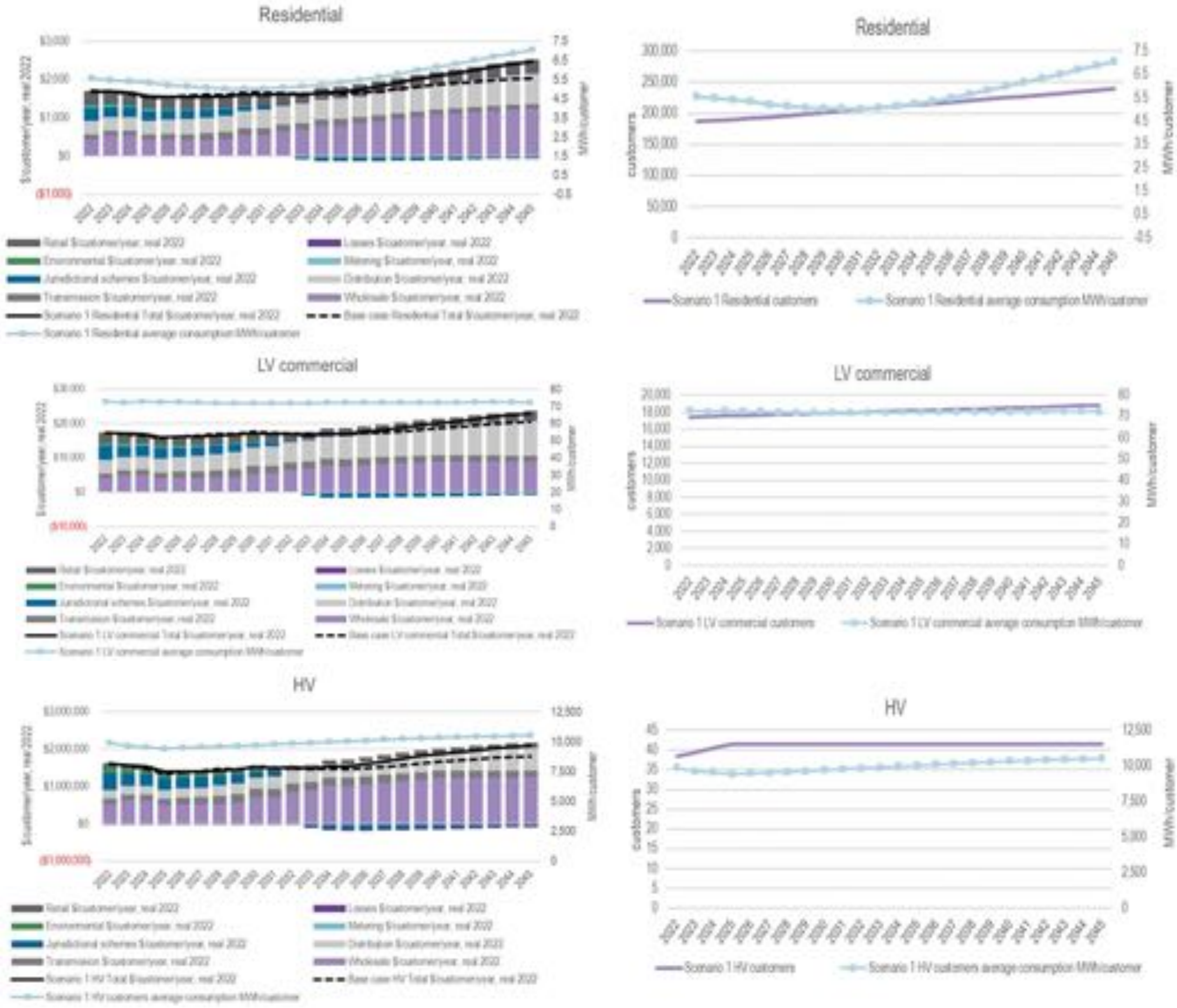
Over the period from 2030 to 2045, projected retail bills for residential, LV commercial and HV customers increase by 52 per cent, 33 per cent and 37 per cent, respectively. These increases reflect the projected increase in wholesale and distribution network costs, which are only partially offset by the projected decline in large FiT payments.

In Scenario 1, the retail bills for residential, LV commercial and HV customers (in real terms) are projected to increase by 47 per cent, 32 per cent and 30 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 19 per cent, 19 per cent and 12 per cent, respectively).

At the start of the projection period, wholesale costs comprise around 30 per cent of the residential bill, distribution costs 20 per cent, and large FiT costs 20 per cent. By 2045, wholesale costs grow to 55 per cent of the residential bill, distribution costs grow to 30 per cent and large FiT costs decline to around two per cent. A similar trend is projected for the low voltage and high voltage commercial bills.

[22] 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.

Figure 90 *Projected retail bill, by component (left chart), by customer type ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS) – Scenario 1 vs base case; Projected customer numbers (right chart)*

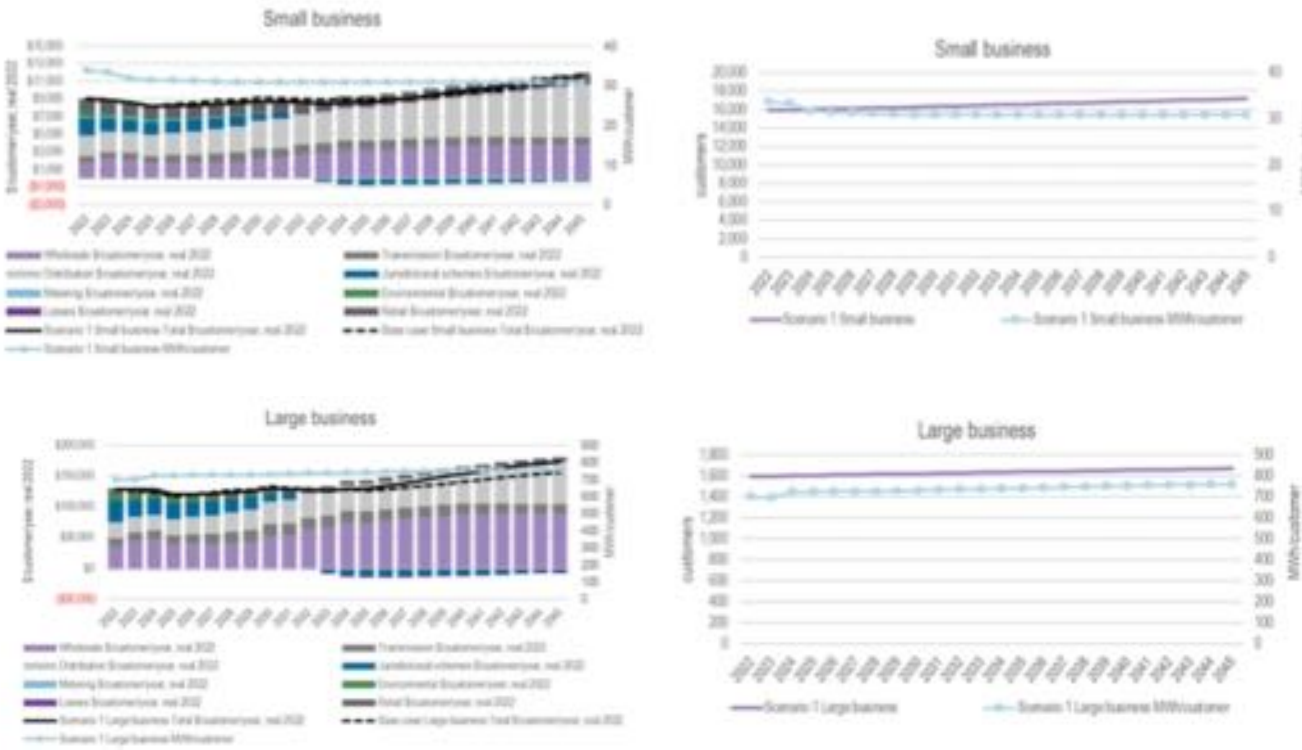


Source: ACIL Allen

6.6.5.1 Retail bill using AER customer classes

Figure 91 shows the average retail bill per customer per year for small business and large business customers (as per the AER definitions). Under both the Evoenergy and AER classifications residential customers are identical. In Scenario 1, retail bills for small and large business customers (in real terms) are projected to increase by 29 per cent and 34 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 20 per cent and 21 per cent, respectively). These increases reflect the projected increase in wholesale and distribution network costs, which are only partially offset by the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes. At the start of the projection period, wholesale costs comprise around 20 per cent of the small business bill, distribution costs 27 per cent, and large FiT costs, 23 per cent. By 2045, wholesale costs grow to 36 per cent of the bill, distribution costs grow to 47 per cent and large FiT costs decline to around three per cent. A similar trend is projected for the large business bill, except that in 2045 wholesale costs grow to a larger proportion (50 per cent) and distribution costs to a lesser proportion (40 per cent) of the total bill.

Figure 91 Projected retail bill (left chart), by component, of small and large business customers ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS) – Scenario 1 vs base case; Projected customer numbers (right chart)



Source: ACIL Allen

6.7 Costs and benefits to the ACT economy

The transition of the ACT energy system under the alternative decarbonisation scenarios will come with a range of costs and benefits compared to the base case. Broadly, there will be a range of additional expenses related to increasing renewable electricity usage, but these will be offset by reductions in gas, petrol and diesel usage and their associated costs. In addition, there will be extra reduction in GHG emissions under the alternative decarbonisation scenarios compared to the base case.

Table 11 summarises the various direct costs and benefits of Scenario 1 compared to the base case.

Table 11 Costs and benefits of Scenario 1, relative to the base case

		Total	NPV4	NPV7	NPV10
	Description	**real A$m**	**real A$m**	**real A$m**	**real A$m**
	COSTS				
	Additional CAPEX (relative to the base case)				

	Description	Total real A$m	NPV4 real A$m	NPV7 real A$m	NPV10 real A$m
1	Electricity network and distribution	1,390.6	640.0	433.5	282.6
2	Grid connected batteries	488.9	326.6	273.1	248.5
3	Behind the meter PV and batteries	472.3	341.4	301.0	270.9
4	ZEVs cost premium	951.2	536.5	404.6	312.4
5	Appliances (net)	4.6	2.5	1.8	1.3
6	Net additional retail electricity cost	662.3	283.5	191.9	122.7
7	Energy efficiency capital expenses	*Not costed*	*Not costed*	*Not costed*	*Not costed*
A	**Total change in costs [=1+2+3+4+5+6+7]**	**3,969.8**	**2,130.5**	**1,605.9**	**1,238.5**
	BENEFITS				
8	Reduced gas network and distribution CAPEX	9.8	4.9	3.5	2.5
9	Net reduction in retail gas cost	337.4	161.1	114.8	77.4
10	Reduced vehicle retail fuel cost	1,922.7	979.4	707.6	509.3
11	Reduced vehicle human health costs	218.4	110.9	80.1	57.4
B	**Total benefits (excl. GHG) [=8+9+10+11]**	**2,488.3**	**1,256.3**	**905.9**	**646.6**
C	**Net change in costs (relative to the base case) [=A-B]**	**1,481.5**	**874.1**	**699.9**	**591.9**
	REDUCTION IN GHG EMISSIONS	kt CO_2-e	kt CO_2-e	kt CO_2-e	kt CO_2-e
12	Reduced vehicle fuel use	1,689.5	1,689.5	1,689.5	1,689.5
13	Reduced gas use	635.0	635.0	635.0	635.0
14	Changes in electricity consumption	0	0	0	0
D	**Total reduction in GHG emissions [=12+13+14]**	**2,324.6**	**2,324.6**	**2,324.6**	**2,324.6**
		$/t CO_2-e	**$/t CO_2-e**	**$/t CO_2-e**	**$/t CO_2-e**
E	**Implied abatement cost [=C/(D/1000)]**	**637.3**	**376.0**	**301.1**	**254.6**

Note: All dollars are in real 2022 terms. Pricing for (6) Net electricity costs, excludes the pass through of capital expenditure (1) to customers. The additional cost of (2) Grid connected batteries, includes additional annual fixed operating and maintenance costs. There is no change in emissions from electricity given the policy of purchasing 100% renewable electricity.

Source: ACIL Allen

6.7.1 Costs

In total, there are expected to be an additional $4.0 billion in costs (with a net present value of $1.6 billion, using a seven per cent real discount rate (NPV7)) associated with the increased electricity usage. Compared to the base case, this comprises:

- $1,391 million (or NPV7 of $434 million) of additional capital expenses associated with upgrading the ACT electricity network (taken from the RAB figures – conservative estimates).
- $489 million (or NPV7 of $273 million) of additional capital expenses associated with installing large scale and community batteries (with capital costs in each year taken from *PowerMark*). In calculating this cost, these battery systems have been assumed to have a usable life of 12 years before needing to be replaced. It also includes a provision for additional annual fixed operating and maintenance costs.
- $472 million (or NPV7 of $301 million) of additional capital expenses associated with behind the meter residential and commercial rooftop PV systems and battery storage (with capital costs in each year taken from *PowerMark*). In calculating this cost, the PV panels are assumed to have a 25-year life, with inverters and battery systems assumed to have a usable life of 12.5 years before needing to be replaced.
- $951 million (or NPV7 of $405 million) of additional vehicle purchase costs associated with buying ZEVs instead of conventional and hybrid ICE vehicles. In calculating this cost, the vehicle numbers and average kilometres travelled per vehicle were taken from the 'optimistic' versus the 'conservative' EPSDD projections (as per the provided Deloitte analysis). The purchase cost premium (not including any subsidies on the purchase price or registration) for ZEVs versus ICE vehicles is assumed to be $12,000 per vehicle currently,[23] falling to $8,000 by 2030 and $5,000 by 2045. This price implicitly includes any additional behind the meter expenses incurred by vehicle owners in modifying their home or business to add charging points etc. (Note: this upfront cost is offset by reduced petrol and diesel purchases which are included in (10) below.)
- $4.6 million (or NPV7 of $1.8 million) of additional purchase and installation costs for converting gas appliances to electric. The number of appliance conversions (including ducted and non-ducted space heaters, mains and solar boosted hot water, cooktops and ovens) directly relate to the gas demand projections in each scenario, while the purchase and installation costs have been taken from modelling for EPSDD[24]. The cost differentials are based on the appliance type with some electric appliances being cheaper, the same, or more expensive than the gas alternative. In aggregate, the appliance conversions costs in Scenario 1 are slightly higher than the base case.
- $662 million (or NPV7 of $192 million) of additional retail electricity costs for consumers. These costs include the total additional quantity of electricity purchased from the grid by consumers for all purposes (e.g. running

[23] Due to the relative infancy of the ZEV market, it is difficult to make a true comparison of the costs of a ZEV with an equivalent ICE vehicle. Hyundai Kona and the Mini Cooper are two exceptions in that an ICE and a ZEV version of (approximately) the same vehicles are available for sale in Australia. Excluding any subsidies or other Government incentives, as of January 2022 the Kona Elite cost was $34,853 driveaway, while the Kona Elite ZEV was $57,018 (+$22,435). Similarly, the Kona Highlander had a recommended driveaway price of $41,317 while the Kona Highlander ZEV was $$60,518 (+$19,201). Similarly, the Mini 3-door Cooper has a driveaway price of $42,961, while the full electric version was $61,479 (+$18,518). Besides the fuel savings, differences in servicing costs, tyre wear, insurance, and depreciation all affect the total lifecycle cost of each type of vehicle. The initial assumption of a $12,000 price gap is considered to be a conservative estimate of the additional cost of ZEVs versus ICEs (excluding subsidies and not including fuel savings which are calculated separately).

[24] ACIL Allen Consulting (2020), *Household Energy Choice in the ACT: Modelling and analysis*, Report for Environment, Planning and Sustainable Development Directorate ACT, Canberra

additional ZEVs and electric appliances), net of electricity generated behind the meter by residential and commercial PV installations. In terms of the price, it excludes the pass through of additional network and distribution expenses since this is included in cost item (1).

- No costing of the energy efficiency improvements has been undertaken, but the benefits are included in (6). Scenario 1: *Technology drives change*, assumes moderate government support for energy efficiency, and improvements in efficiency standards, which leads to moderate energy savings of around 685 GWh by 2045 (200 GWh or around 40 per cent more energy savings than the base case).

6.7.2 Benefits

In terms of benefits, Scenario 1 is expected to save ACT consumers $2.5 billion (or NPV7 of $906 million) in gas and fuel costs compared to the base case. This comprises savings of:

- $9.8 million (or NPV7 of $3.5 million) of reduced capital expenditures related to maintaining the gas network (from the assumptions underlying the retail pricing model for the gas market projections).
- $337 million (or NPV7 of $115 million) of reduced gas purchases by ACT consumers.
- $1,923 million (or NPV7 of $708 million) of reduced petrol and diesel expenses related to running additional ZEVs in Scenario 1 instead of ICE vehicles in the base case. In calculating this, the average vehicle kilometres travelled per vehicle were taken from the Deloitte analysis, while fuel demand for passenger vehicles is based on DITRDC (2021),[25] and has average fuel efficiency increasing gradually from 10.3 litres/100 km in 2021 to 8.4 litres/100 km by 2045. Fuel prices are projected to increase gradually to $2.05 cents/litre based on the long-run crude oil price projections under the Stated Polices Scenario (SPS) in the IEA's World Energy Outlook 2021,[26] which project that the price of oil will be US$82/barrel in 2020 prices by 2040. An exchange rate of A$0.73/US$ was applied to convert into Australian dollars.
- $218 million (or NPV7 of $80 million) of reduced human health costs associated with a reduction in noxious emissions from ICE vehicles as a result of the increased uptake of ZEVs in Scenario 1 compared to the base case. In calculating this, Australia currently has Euro 5 equivalent noxious emissions standards and these have been assumed to remain in place out to 2045. Emissions factors for noxious emissions have been taken from DITRDC (2021) with health impacts calculated using the same damage cost approach as in DITRDC (2021). This results in savings of human health costs of approximately 1.88-1.98c/km between 2021 and 2045.

6.7.3 Net cost and GHG emissions

The net change in the direct costs of Scenario 1 compared to the base case is therefore estimated to be +$1,482 million (or NPV7 of +$700 million). Note that this costing does not include the cost of achieving the additional 685 GWh of energy efficiency improvements (over the base case) by 2045 (which are around 40 per cent more than in the base case).

[25] DITRDC (2021), Light vehicle emission standards for cleaner air, Draft Regulation Impact Statement, October 2020
[26] International Energy Agency (2021), World Energy Outlook 2021, OECD Publishing, Paris.

In addition to the benefits discussed above, Scenario 1 will also result in a reduction of GHG emissions over the period to 2045 of 2,325 kt CO_2-e, comprising:

- A reduction of 1,690 kt CO_2-e associated with reduced fuel use in passenger vehicles. This is based on the emission intensity of fuels as per DITRDC (2021).
- A reduction of 635 kt CO_2-e associated with reduced gas use in the ACT (taken from the gas market projections).
- No change in GHG emissions associated with the additional electricity consumed. Despite there being an increase in total electricity generation from behind the meter PV and a total increase in electricity consumption, there aren't expected to be any net changes in GHG emissions associated in any of the scenarios compared to the base case beyond that explicitly estimated in (11) and (12) above. This reflects the Governments in perpetuity policy commitment to purchasing 100 per cent renewable electricity.

6.7.4 Implied emissions abatement cost

Comparing the net cost of Scenario 1 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. As per (E) in Table 11, the total undiscounted net cost of Scenario 1 implies a GHG emission abatement cost of +$637/t CO_2-e, with an NPV7 abatement cost of +$301/t CO_2-e. Again, it should be noted that while the benefit of reduced energy demand associated with additional energy efficiency technologies is included in these estimates, the associated capital costs are not.

By comparison, in early 2022, emission allowances in the EU Emissions Trading System (EU ETS) were trading at around €80–100/t CO_2-e (equivalent to approximately A$120–160/t CO_2-e).

6.8 ACT economy-wide analysis

As discussed in Section 3.2.2, undertaking large scale transition of the ACT energy system will result in a range of economic impacts beyond those analysed in Section 5.7.

Some of these will be positive (such as reductions in energy prices or energy efficiency improving the cost of living of residents or the competitiveness of local ACT businesses, or additional investment activity increasing demand for labour thereby increasing employment or migration to the ACT) while some will be negative (such as increases in energy prices increasing the cost of living of residents or reducing the competitiveness of local businesses, or the additional investment requirements crowding out other investment or current consumption).

Further, the relative local content of alternative investment or consumption options can also result in additional second or third round effects on the core drivers underlying each scenario. Indeed, in each scenario the complexities associated with the energy transition mean that there are generally a wide range of competing positives and negatives for businesses and residents in any particular year, making it difficult to disentangle individual impacts. In such circumstances, CGE models are generally the preferred tool for estimating the net macroeconomic impacts. This Section presents the projected macroeconomic impacts using CGE modelling.

6.8.1 Measures of macroeconomic impacts

One of the most commonly quoted macroeconomic variables at a national level is real GDP, which is a measure of the aggregate output generated by an economy over a given period of time (typically a year). GDP may be calculated in different ways:

- on the expenditure side by adding together total private and government consumption, investment and net trade
- on the income side as the sum of returns to the primary factors of production (labour, capital and natural resources) employed in the national economy plus indirect tax revenue.

The territory level equivalent to GDP is GTP. These measures of the real economic output of an economy should be distinguished from measures of the economy's real income, which provide a better indication of the economic welfare of the residents of a region. It is possible for real economic output to increase (that is, for GTP to rise) while at the same time real income (economic welfare) declines. In such circumstances, people and households would be worse off despite economic growth.

As shown in Figure 92, the change in a region's real income as a result of a change in policy scenario is the change in real GTP plus the change in net external income transfers plus the change in the region's terms of trade (which measure the change in the purchasing power of the region's exports relative to its imports). As Australians have experienced first-hand in recent years, changes in the terms of trade can have a substantial impact on residents' welfare, independent of changes in real economic output.

In global CGE models such as *Tasman Global*, the change in real income is equivalent to the change in consumer welfare using the equivalent variation measure of welfare change resulting from exogenous shocks. Hence, it is valid to say that the projected change in real income (from *Tasman Global*) is also the projected change in consumer welfare.

6.8.2 Macroeconomic impacts

Figure 92 presents the annual macroeconomic and employment impacts of Scenario 1, relative to the base case, while Table 12 presents the cumulative impacts over the period to 2045.

There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, electricity prices and volumes, gas prices and volumes, and vehicle fuel purchases. In total, over the period to 2045, the cumulative difference of Scenario 1 relative to the base case is:

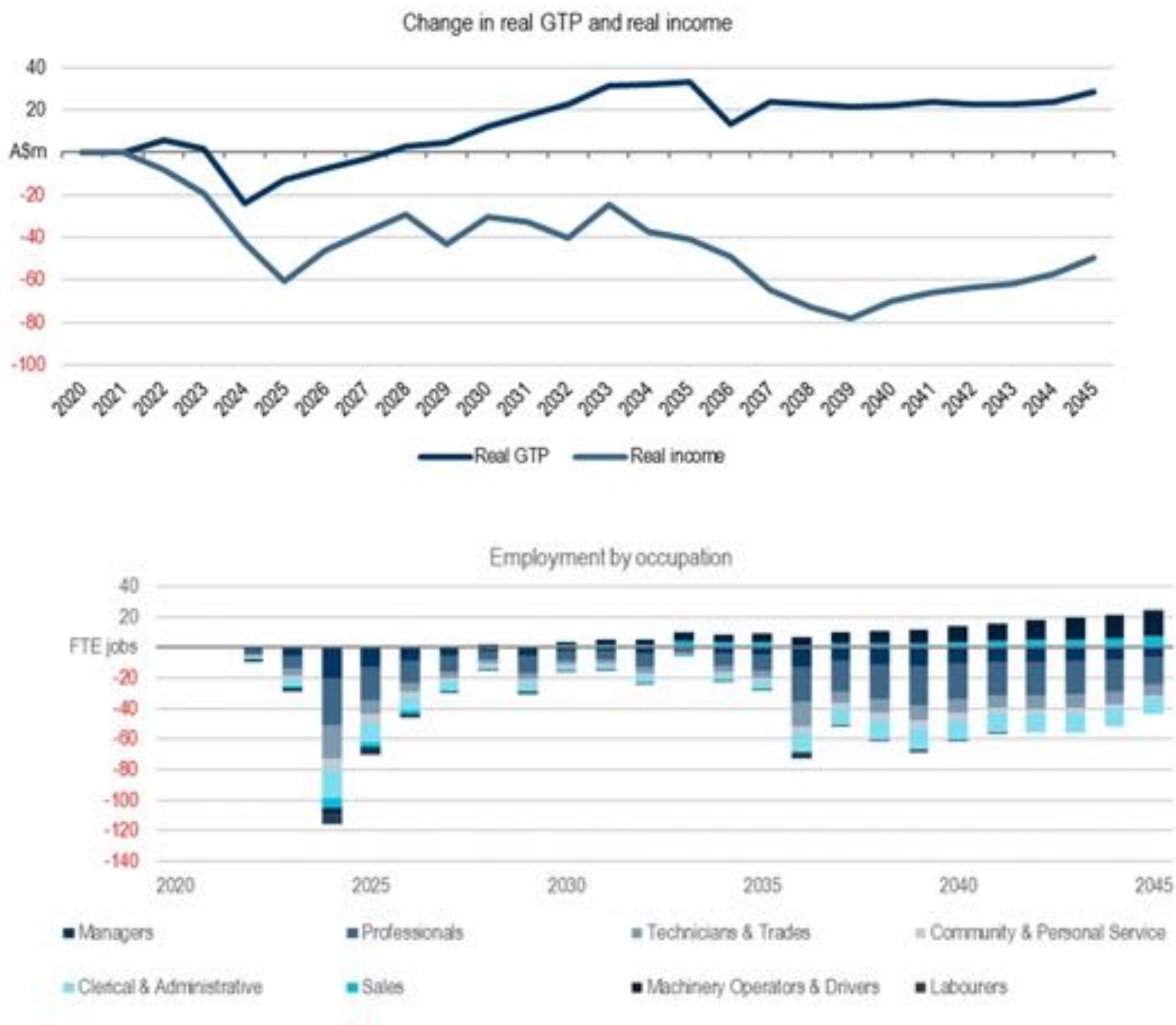
- +$340 million (or NPV7 of +$100 million) increase in the real GTP of the ACT, driven largely by the stimulus benefit of the additional capital expenditure and fuel savings from ZEVs outweighing the negative impact of higher electricity prices
- -$1,125 million (or NPV7 of -$474 million) change in the real income of ACT residents, driven by a longer-term loss in purchasing power and income transfers
- -834 employee years of employment (annual average change of -33 FTE jobs a year) in line with the lower real income - these job impacts are felt fairly uniformly across different occupations, except within the Machinery Operators & Drivers categories which experience a small net increase over the longer term.

Table 12 Total macroeconomic impacts of Scenario 1, relative to the base case

	Total	NPV4	NPV7	NPV10
	real A$m	real A$m	real A$m	real A$m
Real economic output (GTP)	340.3	200.1	100.3	59.8
Real income	-1,125.3	-752.1	-474.4	-353.7
	Total	**Annual average**		
	Employee years	FTE jobs		
Employment	-834	-33		

Note: All dollars are in real 2022 terms.
Source: ACIL Allen

Figure 92 Annual macroeconomic impacts of Scenario 1, relative to the base case



Source: ACIL Allen

7. Scenario 2: *Decentralisation is king*

This Chapter sets out a summary of the Scenario 2 techno-economic modelling results.

7.1 Scenario description

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.

The key variables for Scenario 2 *Decentralisation is king* are detailed at Table 13.

Table 13 Scenario 2 Decentralisation is king: key variables

Variable	Description	*Decentralisation is king*
Demand for gas from gas network	Change compared from current level of gas demand (note that an gas supplied is either biogas or hydrogen (actual or offsets))	~80% reduction
Rate of gas household electrification	Percentage of existing gas customers that switch to electricity each year	1-3% p.a. (rising); initially follows base case, rising from 2035
Residential rooftop PV uptake (by 2045).	Percentage of households with suitable roof space on which PV panels have been installed	90%
Residential batteries uptake	Percentage of installed domestic PV systems with batteries	75%
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%
Batteries	Amount of large-scale battery storage installed by 2045	660MW
	Amount of neighbourhood/community battery storage installed by 2045	400MW
Energy efficiency	Level of energy efficiency (low/moderate/high) Annual energy savings (GWh) in 2045 Percentage change from base case.	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.
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes autonomous vehicles (Avs) – all assumed to be electric)	68%

Variable	Description	*Decentralisation is king*
Use of EVs for V2H and V2G	Percentage of EVs that are used as 'batteries' to supply homes (V2H) or the grid (V2G) (based on the 'hydrogen superPower' scenario in the latest ISP assumptions workbook)	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	Low

7.2 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 (discussed in more detail in Section 6.3). 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 ZEVs in the *Decentralisation is king* scenario is like that seen in Scenario 1. Sales of new ICE vehicles cease by 2035. Private ZEVs 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.

ZEVs can be used as batteries when they are not being used as transport. The ZEVs can provide stored electricity either directly to the grid (V2G) or to the home (V2H). The number of ZEVs 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.

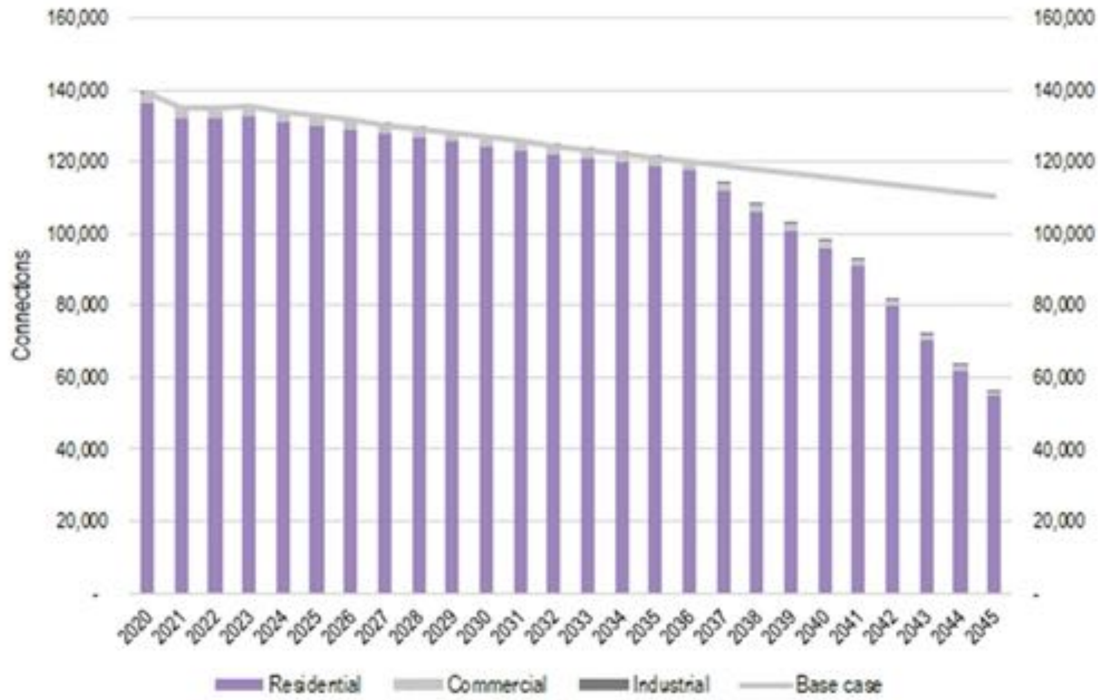
The *Decentralisation is king* scenario sees much greater consumer interest in improving energy efficiency. This is driven by consumers' desire to improve the comfort of their homes and ensure that their energy use can largely be met from the own household PV/battery systems. Strong government support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

7.3 Gas market projections

7.3.1 Connections

Projected gas connections in the ACT under Scenario 2 are provided at Figure 93. Scenario 2 assumes connections will decline at a similar rate to the base case before steepening significantly post 2035. The driver of this profile is that the transition away from natural gas happens later than in Scenario 1, but when the transition occurs it happens at a faster pace.

Figure 93 Projected gas connections, ACT – Scenario 2 vs base case



Source: ACIL Allen

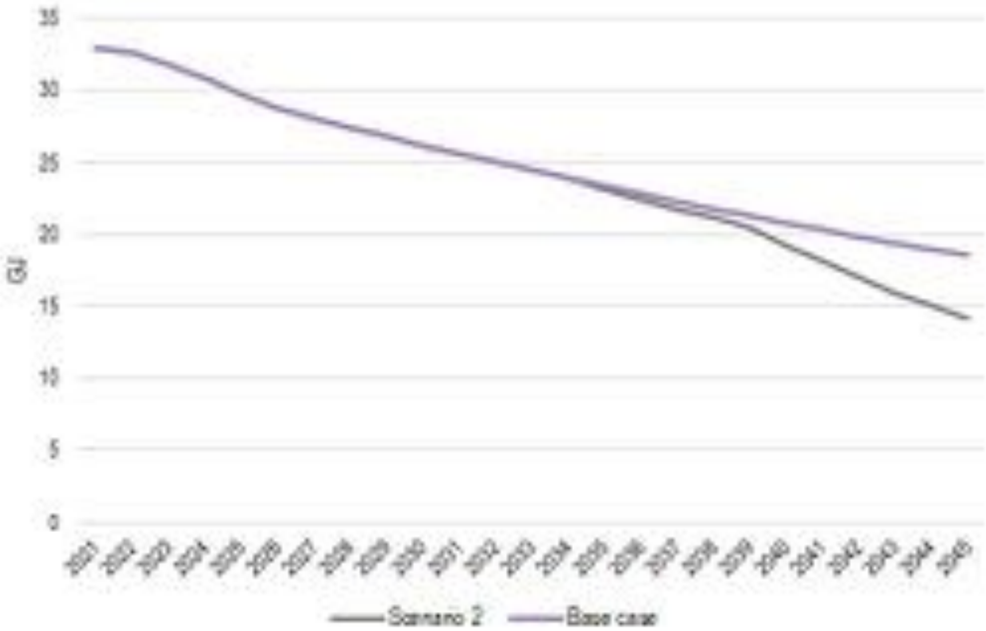
This scenario represents a situation where the government policy drivers are not as immediate to start transitioning customers to electricity or potentially small-scale hydrogen/biogas. Total connections in the ACT (excluding Queanbeyan) will drop from around 140,000 in 2020 to less than 60,000 in 2045, similar to that of Scenario 1. This represents a total loss of around 80,000 gas connections, or nearly a 60 per cent decline in connections from current levels. Over the forecast period, connections on average fall by approximately 3.5 per cent per annum (with the high majority of connections falling post 2035).

7.3.1.1 Consumption per connection

Residential and commercial

Residential consumption per connection is expected to drop from levels around 33 GJ per annum to 14 GJ per annum under this scenario. This means residential gas consumers are projected to consume around 57 per cent less than they currently do by 2045.

Figure 94 Projected gas consumption per residential connection – Scenario 2 vs base case

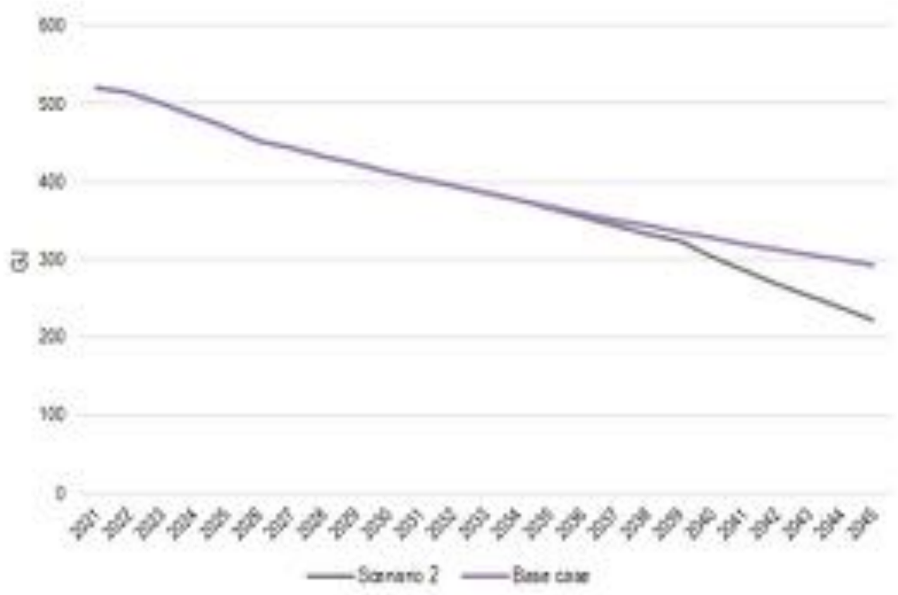


Source: ACIL Allen

The steeper decline assumes household efficiency and appliance efficiency improves more under this scenario than in the base case. However, this scenario represents a case where the policy incentives are delayed (in effect sustaining continued use of the network in the short-term), but are designed to accelerate a faster transition from around 2036 onwards.

Commercial consumption per connection is assumed to drop from levels around 520 GJ per annum to levels around 190 GJ per annum in 2045, representing a 3.3 per cent per cent decline per annum in consumption. Again, this assumption is in line with Scenario 1. Projected residential and commercial consumption per connection is illustrated at Figure 94 and Figure 95.

Figure 95 Projected gas consumption – per commercial connection, by appliance type – Scenario 2 vs base case

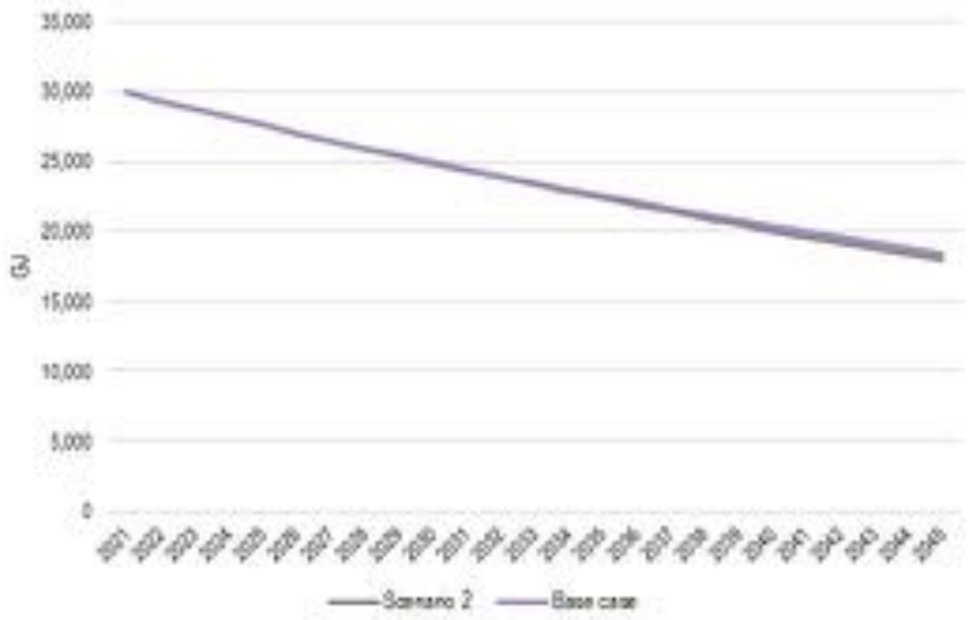


Source: ACIL Allen

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. Figure 96 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 18,500 GJ per annum. This is the same as in Scenario 1. This is a conservative estimate and like in Scenario 1, the reduction in industrial consumption is driven by sites/plants disconnecting from gas, and not by reducing gas consumption.

Figure 96 Projected gas consumption per industrial connection – Scenario 2 vs base case



Source: ACIL Allen

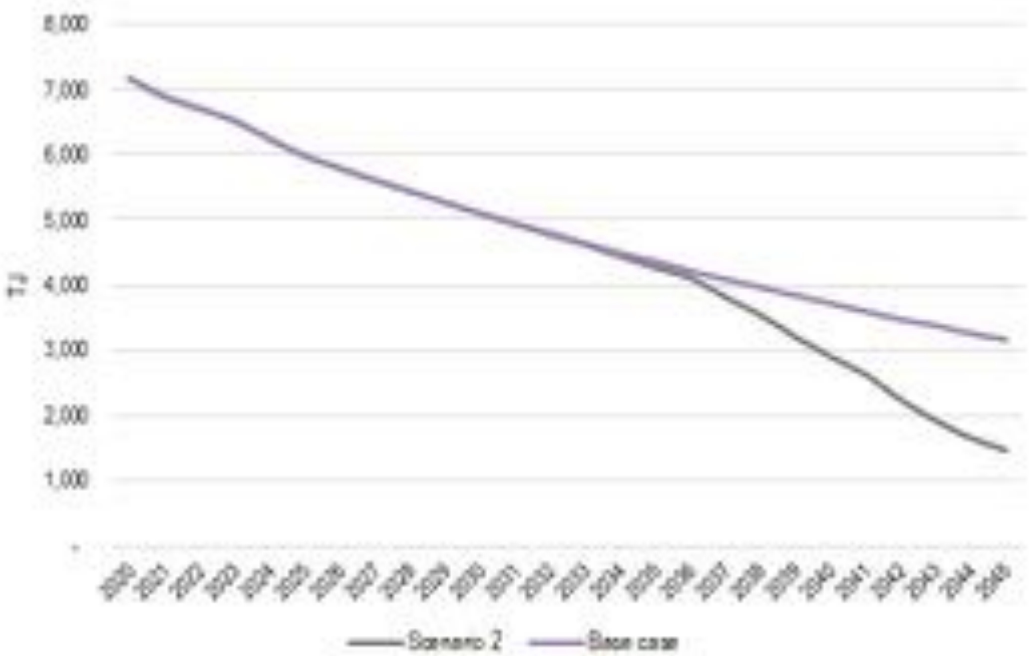
7.3.1.2 Projected total consumption

Total consumption in the ACT to drop from levels around 7,000 TJ currently to levels less than 2,000 TJ by 2045. This represents a decline of approximately 80 per cent. This is compared with the base case in Figure 97. Consumption tracks the base case and then steepens post 2035. From 2035 to 2045, the number of gas connections significantly fall. Under Scenario 2, decarbonisation of the gas sector strengthens later on in the forecast period in comparison to Scenario 1. The composition of demand by the end of the forecast period is much the same as in Scenario 1. Industrial consumption becomes a larger share of total consumption by 2045, given the proportionately larger declines in the residential and commercial sectors.

Switching rates are similar to that in Scenario 1 but increase more after 2040 in Scenario 2, where switching rates accelerate to 15 per cent. This means 1 in 7 households post 2040 are switching to electricity from gas. Prior to 2040 the rate is much slower - around 1 in 50 gas connections moving to electricity in the 2020s, accelerating to around 1 in 30 in the 2030s.

Gas customers may continue to use natural gas over the forecast period for a variety of reasons. Some residential users may face challenges in financing a complete transition to electricity; others may face (building) structural challenges if resident in an apartment or townhouse (the tipping point analysis at Section 8.4 addresses these issues in more detail); while others may have strong personal preferences related to the utility of gas appliances versus electrical appliances. Larger commercial and industrial users may face technical challenges making it difficult to convert while others who rely on natural gas as a feedstock may not have a genuine transition alternative.

Figure 97 Projected total gas consumption – ACT



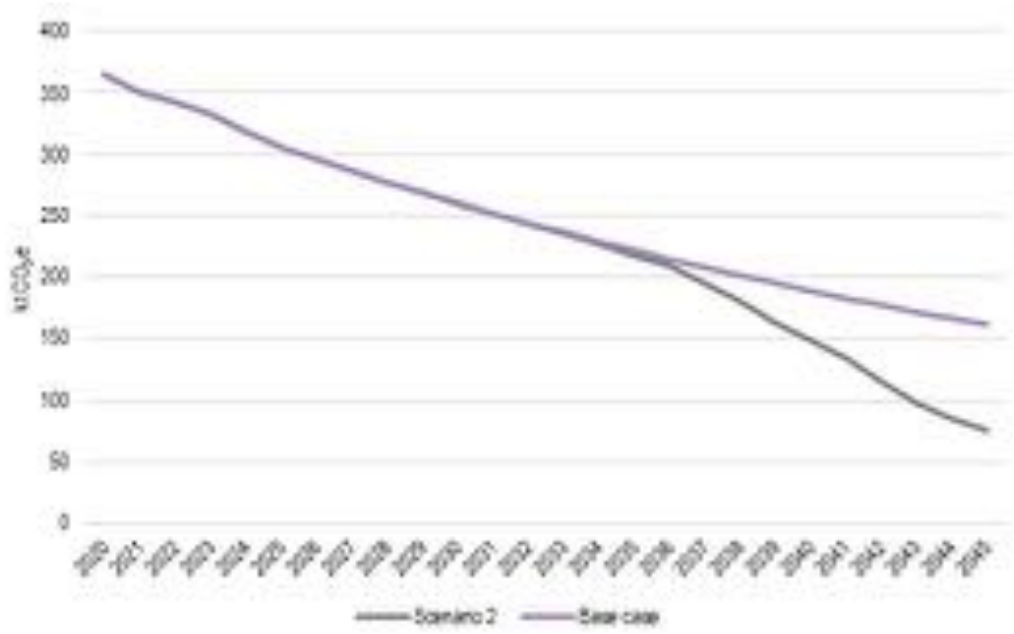
Source: ACIL Allen

7.3.2 Implications of demand forecasts

7.3.2.1 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 350 kt of CO_2. This would reduce to levels around 80 kt by 2045. Emissions are presented below in Figure 98.

Figure 98 Natural gas projected emissions – Scenario 2 vs base case



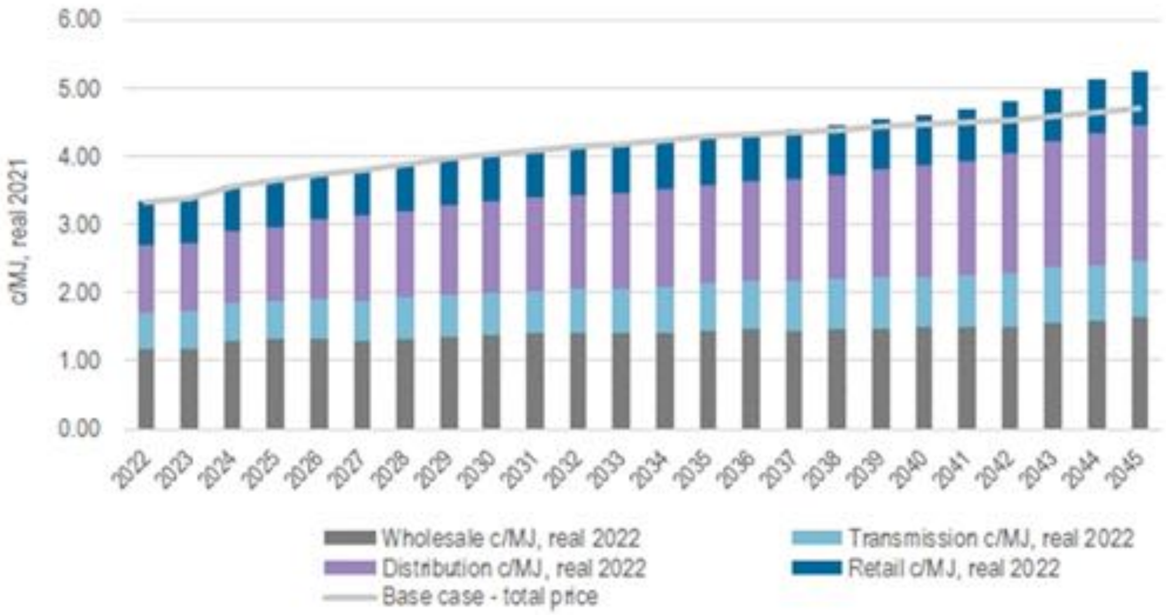
Source: ACIL Allen

7.3.2.2 Gas pricing: retail prices

The total delivered natural gas retail price projected over the projection period is presented below in Figure 99. The price increases in real terms from levels around 3.3 cents/MJ to levels around 5.2 cents/MJ by the mid-2040s. This means for a household consuming around 35 GJ per annum, their residential gas bill would increase from around $1,155 per annum to levels just shy of $1,820 per annum.

The trajectory is similar to that of the base case until late in the 2030s where prices are expected to increase more rapidly as gas connections fall more steeply. By 2045, gas prices are around 15 to 20 per cent higher than in the base case. Analysis around the tipping point and sensitivity on how the AER would regulate prices is assessed in Chapter 9.

Figure 99 ACT retail price for gas delivered to residential customers



Source: ACIL Allen

7.4 Electricity market modelling

We have adopted the same econometric approach to forecast peak demand and energy consumption in the ACT as was used for the base case. The modelling outcomes in relation to the key parameters varied from the base case are discussed in turn below.

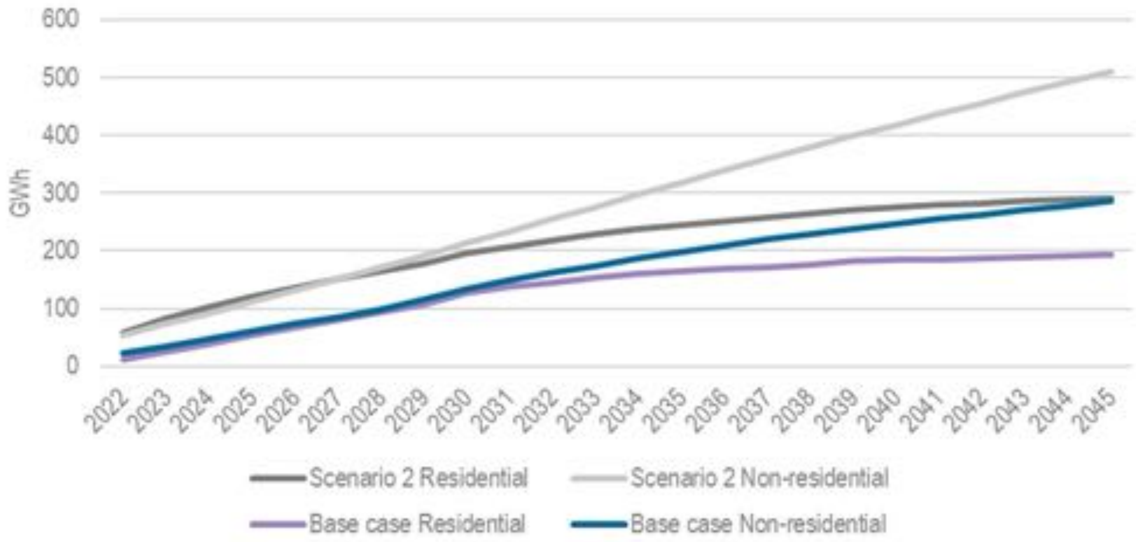
7.4.1 Energy and peak demand forecast

7.4.1.1 Energy efficiency

Scenario 2 assumes a moderate to high level of energy efficiency with savings of around 800 GWh by 2045 or around 65 per cent more energy savings than the base case (see Figure 100). Scenario 2 is based on AEMO's ISP 'Strong electrification' scenario and assumes NCC of 7 stars in 2022, 7.5 stars in 2027, 8 stars in 2030, and 8.5 from 2035.

As discussed in the **Base case Report**, the scenarios include an explicit amount of energy efficiency savings which equal the amount of energy savings in GWh over and above the base case level.

Figure 100 Projected energy efficiency (GWh) – Scenario 2 vs base case

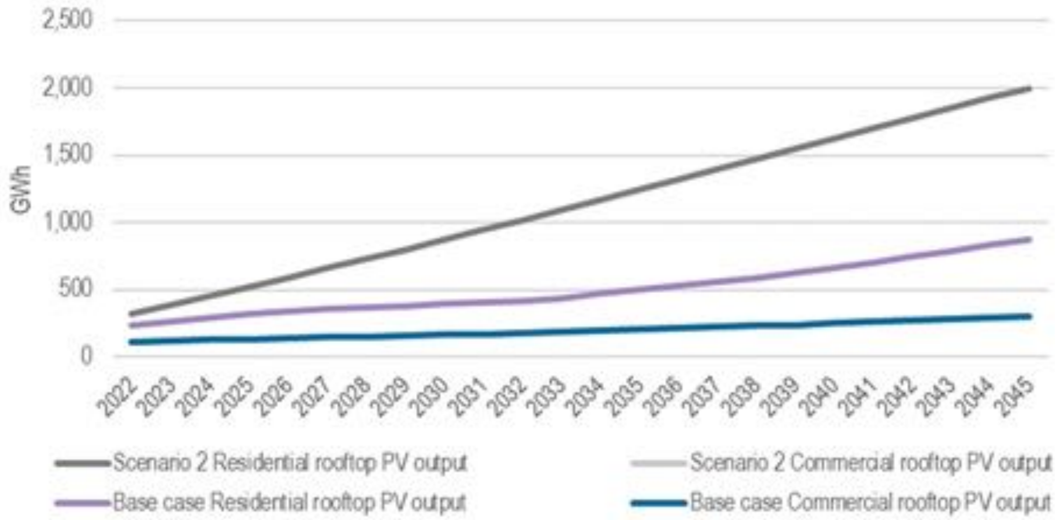


Source: AEMO ISP, ACIL Allen analysis

7.4.1.2 Behind-the-meter solar and battery energy storage systems

Scenario 2 assumes residential and commercial rooftop PV uptake reaches 90 per cent and 90 per cent of suitable rooftops, respectively, compared to 47 per cent and 90 per cent under the base case (see Figure 101).

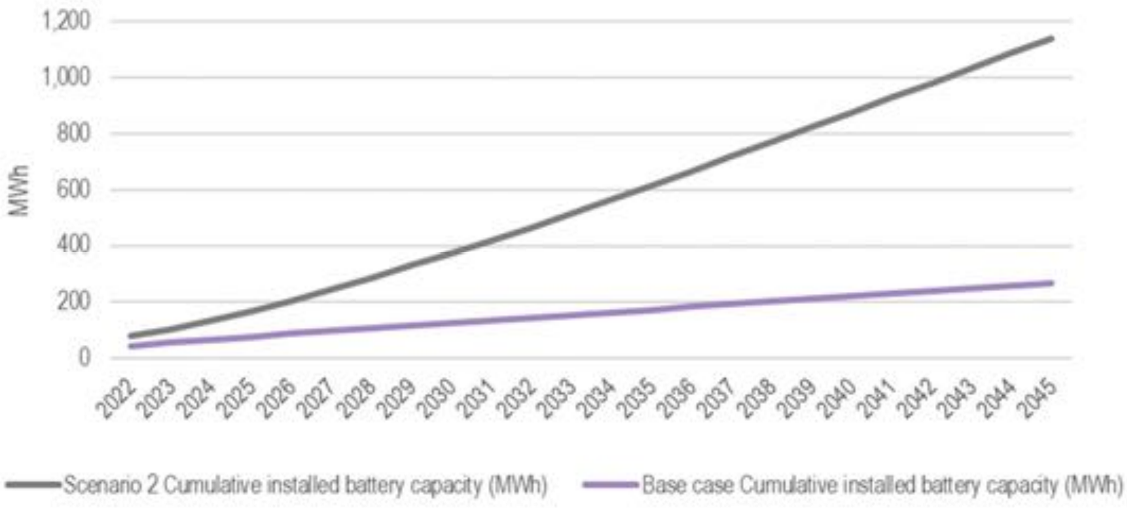
Figure 101 Projected rooftop PV output in the ACT, by consumer type (GWh) – Scenario 2 vs base case



Note: Installations less than 100 kW. Scenario 2 commercial uptake is the same as the base case (thus plot not visible).
Source: ACIL Allen

Scenario 2 assumes behind-the-meter BESS uptake reaches 75 per cent of installed rooftop PV systems by 2045, compared to 25 per cent in the base case as shown in Figure 102. BESS uptake at this level will be reliant on improved battery technology/lower cost, coupled with incentives and electricity price drivers.

Figure 102 Projected cumulative installed behind the meter BESS capacity (MWh) in the ACT – Scenario 2 vs base case

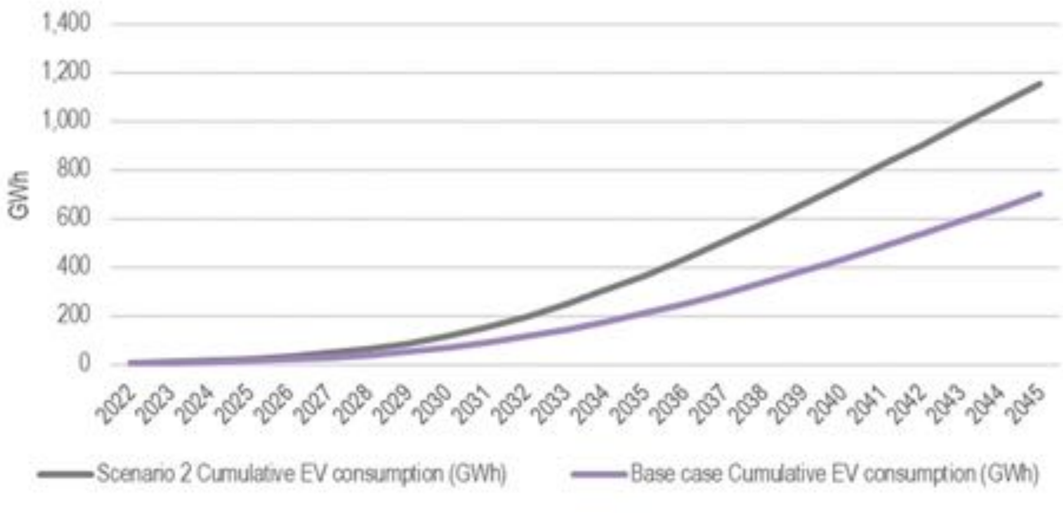


Source: ACIL Allen

7.4.1.3 Zero emission vehicles (ZEVs)

Scenario 2 assumes ZEV uptake reaches 68 per cent by 2045 (same as Scenario 1), compared to 41 per cent in the base case as shown in Figure 103. Of the ZEV fleet, 26 per cent by 2045 are assumed to be used as batteries to supply homes (V2H) or the grid (V2G).

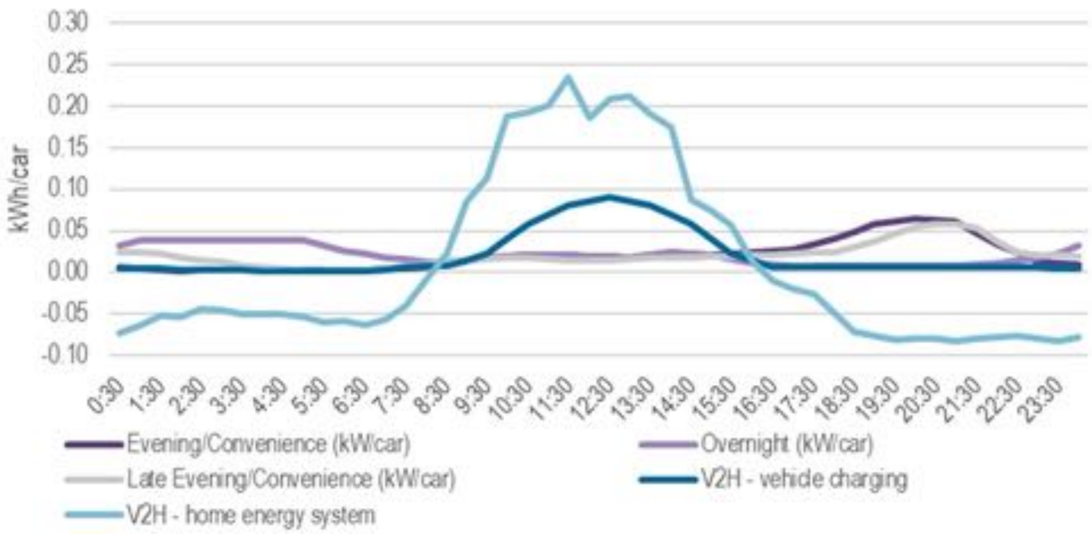
Figure 103 Projected annual energy requirements of passenger ZEV charging (GWh) – Scenario 2 vs base case



Source: Projections obtained from the EPSDD '2021-ACT ZEV Key insights (confidential 'Deloitte report)

In addition to the charging profiles used in the base case (e.g. convenience, overnight, etc.), Scenario 2 incorporates a V2H vehicle charging profile and home energy system charging profile as shown in Figure 104, based on AEMO's latest ISP assumptions and are identical that those assumed in Scenario 1. The V2H has two profiles, "vehicle charging" for the purpose of charging the vehicle for transport purposes and "home energy system" that covers the storing and withdrawing of energy in the ZEV for the purposes of managing the household demand.

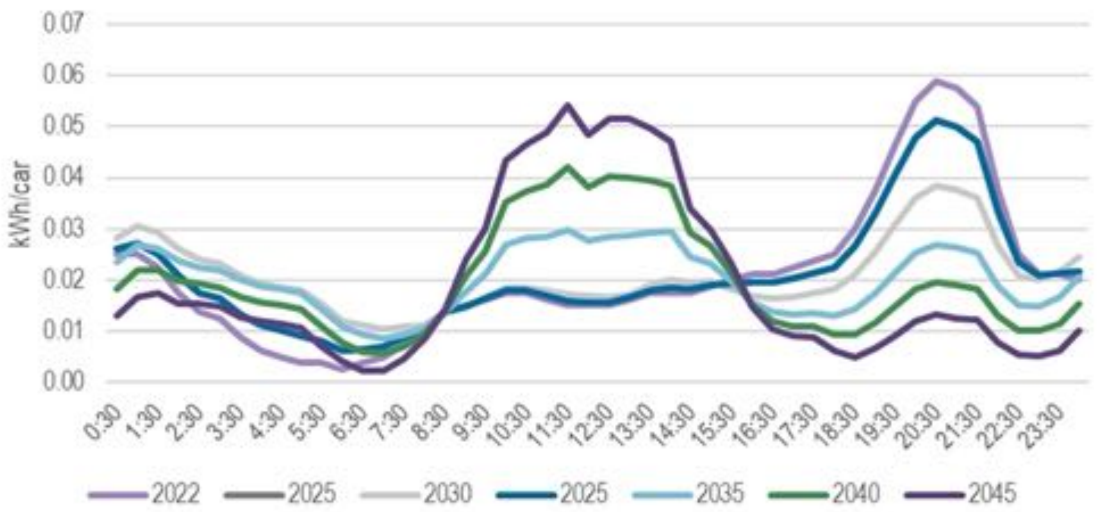
Figure 104 Average time of day ZEV charging profiles (kW/car) – Scenario 2



Source: ACIL Allen analysis of AEMO data

Similar to the base case, 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. As charging infrastructure is further developed and a percentage of ZEVs are used for V2H purposes, 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 (see Figure 105). The daytime peak of EV charging profiles is much more pronounced in Scenario 2 because of the large charging profile of the V2H home energy system. These assumptions are identical to Scenario 1.

Figure 105 Weighted average combined time of day ZEV charging profile (kW/car) – Scenario 2

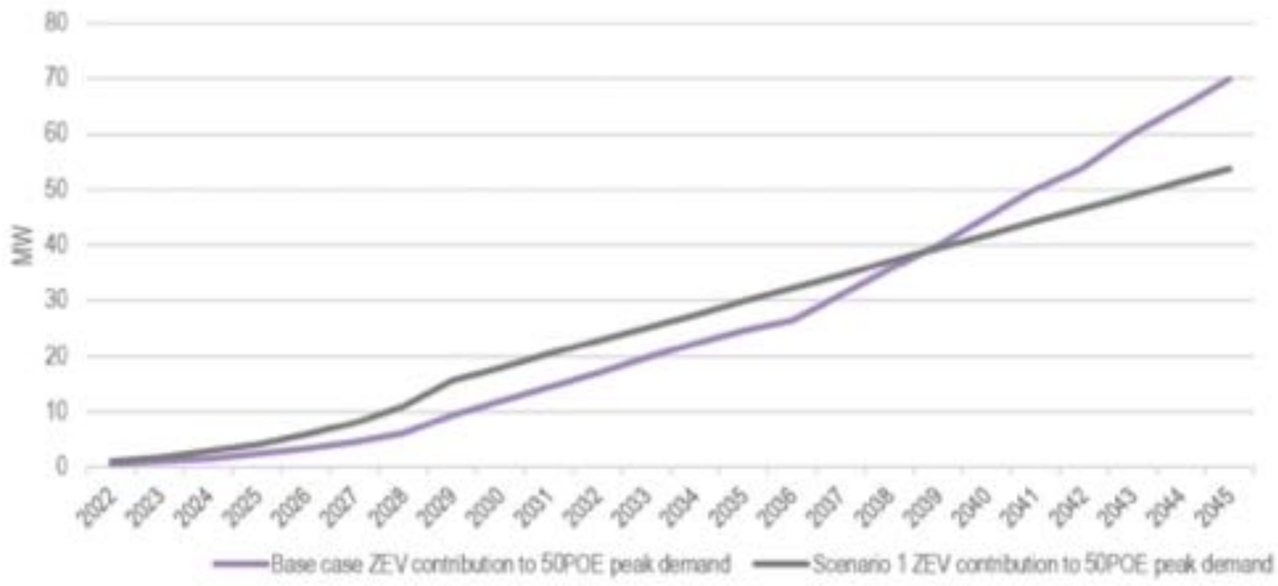


Source: ACIL Allen analysis of AEMO data

Figure 106 shows the projected contribution of ZEVs to 50POE peak demand. As discussed earlier, we used a combination of AEMO's ISP EV charging profiles.

The charging profiles change shape over time to reflect tariff reform and also to reflect the use of EVs as battery storage in the home (V2H).[27] The impact on peak demand in the scenarios is less in the later years due to the assumption of EVs used as batteries in the home and on the grid, which reduces the impact on of EVs on the peak.

Figure 106 Projected contribution of ZEVs to 50POE peak demand (MW) – Scenario 2 vs base case



Source: ACIL Allen

7.4.1.4 Electrification

Scenario 2 assumes demand for gas from the gas network reduces by 80 per cent by 2045 (same as Scenario 1), compared to 60 per cent by 2045 under the base case.

The rate of transition is identical to the base case from 2022 to 2035. From 2036 to 2045, the rate of transition is faster than the base case. The assumptions around electrification of specific commercial loads including the Canberra Hospital, Molonglo Commercial Centre, CIT Woden, Action bus fleet and Canberra Light Rail stage 2 remain unchanged from the base case.

Figure 107 shows projected annual energy requirements from natural gas transition by customer type under Scenario 2 and the base case.

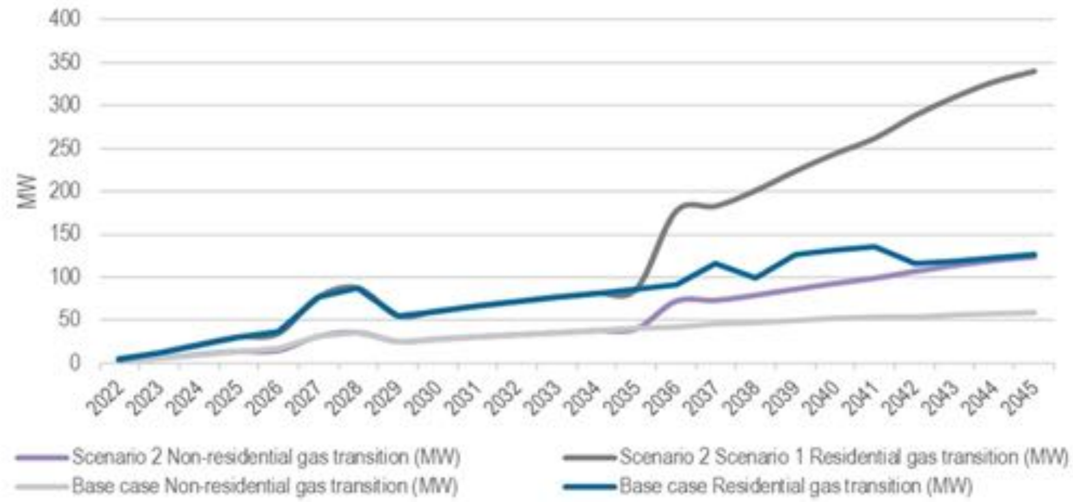
[27] V2H is assumed to ramp up from <1% of EVs in 2030 to 13 per cent by 2045.

Figure 107 Projected energy requirements from natural gas transition (GWh) – Scenario 2 vs base case

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

Projected winter peak requirements attributed to natural gas transition under Scenario 2 and the base case are shown in Figure 108.

Figure 108 Projected contribution to the (winter) 50POE peak by natural gas transition (MW) – Scenario 2 vs base case



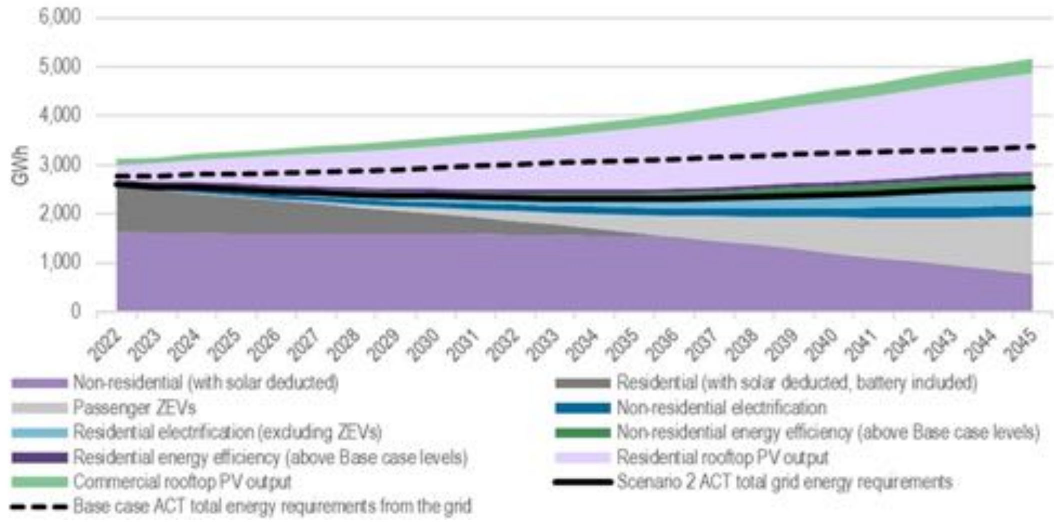
Note: Contribution of gas transition on the day and time of total ACT system 50POE peak demand. Non-residential gas conversion in this figure excludes Canberra Hospital and CNG bus fleet
Source: ACIL Allen analysis

7.4.1.5 Final energy and demand

Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, Figure 109 and Figure 110 below show the final assumed annual energy and peak demand projections. The ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,553 GWh in 2045, which is a decline of around eight per cent over the projection period, compared to an increase of 21 per cent in the base case. This decline is predominantly driven by higher uptake of rooftop PV and a higher level of energy efficiency. ACT 50POE peak grid demand is projected to grow from 654 MW in 2022 to 1,048 MW in 2045, which is an increase of around 60 per cent over the projection period, compared to 48 per cent in the base case.

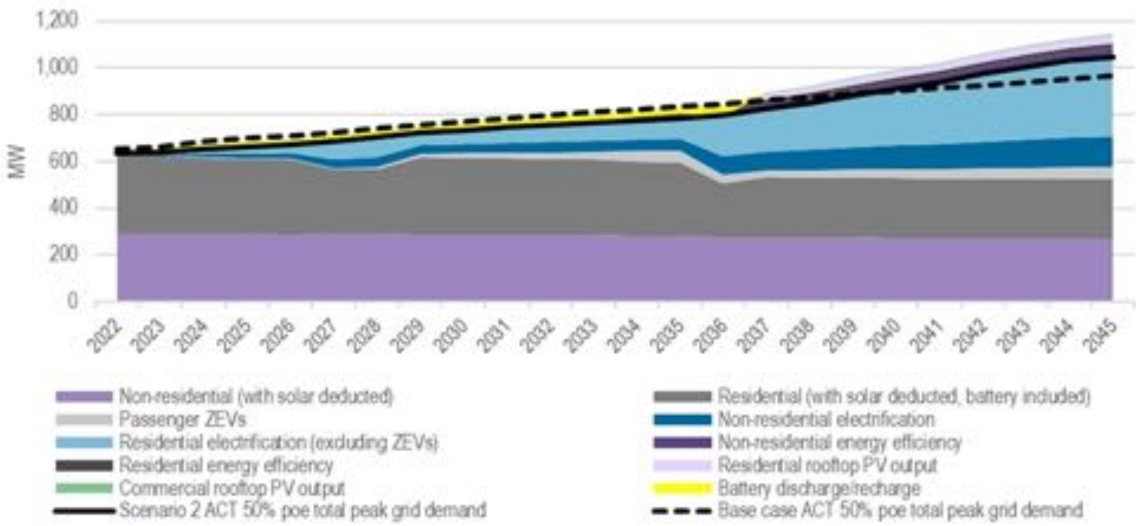
The growth in peak demand is predominantly driven by electrification of space heating requirements during winter mornings. As explained earlier, home batteries are assumed to charge during the middle of the day and discharge during the evening peak (including electrification of space heating requirements during winter evenings). V2H batteries discharge to meet some of the morning space heating requirements.

Figure 109 Projected energy requirements (GWh) – by category – Scenario 2 vs base case



Note: V2H is included in Passenger ZEVs. 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 110 Projected 50POE peak demand (MW) – by category – Scenario 2 vs base case



Note: V2H is included in Passenger ZEVs. 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

Key factors encompassed in this outcome (a decline of around eight per cent over the projection period) include:

- delivery of 47 per cent of total energy requirements through rooftop PV by 2045 supported by home batteries to reduce evening peaks
- ZEVs comprise 68 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 morning and evening because of electrification of space heating
- the impact of behind-the-meter storage on the peak demand is reasonably small given the level of uptake projected (while home BESS is used to meet demand in the evening, it is not sufficient to reduce the overall peak demand which occurs during winter mornings as a result of electrification of space heating - but V2H will meet some of the space heating morning demand)
- taking out 20 per cent more gas consumption (from 60 per cent by 2045 in the base case to 80 per cent by 2045 in Scenario 2) only increases electricity energy requirements by 176 GWh by 2045 or seven per cent of total grid energy requirements by 2045
- taking out 20 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 273 MW by 2045 or 26 per cent of total peak demand by 2045.

7.4.1.6 Average time of day demand

The projected higher uptake of rooftop PV installations, storage, and electrification in Scenario 2 will continue to change the shape of the time-of-day profile of demand in the ACT, resulting in lower average time of day demands during daylight hours compared to the base case.

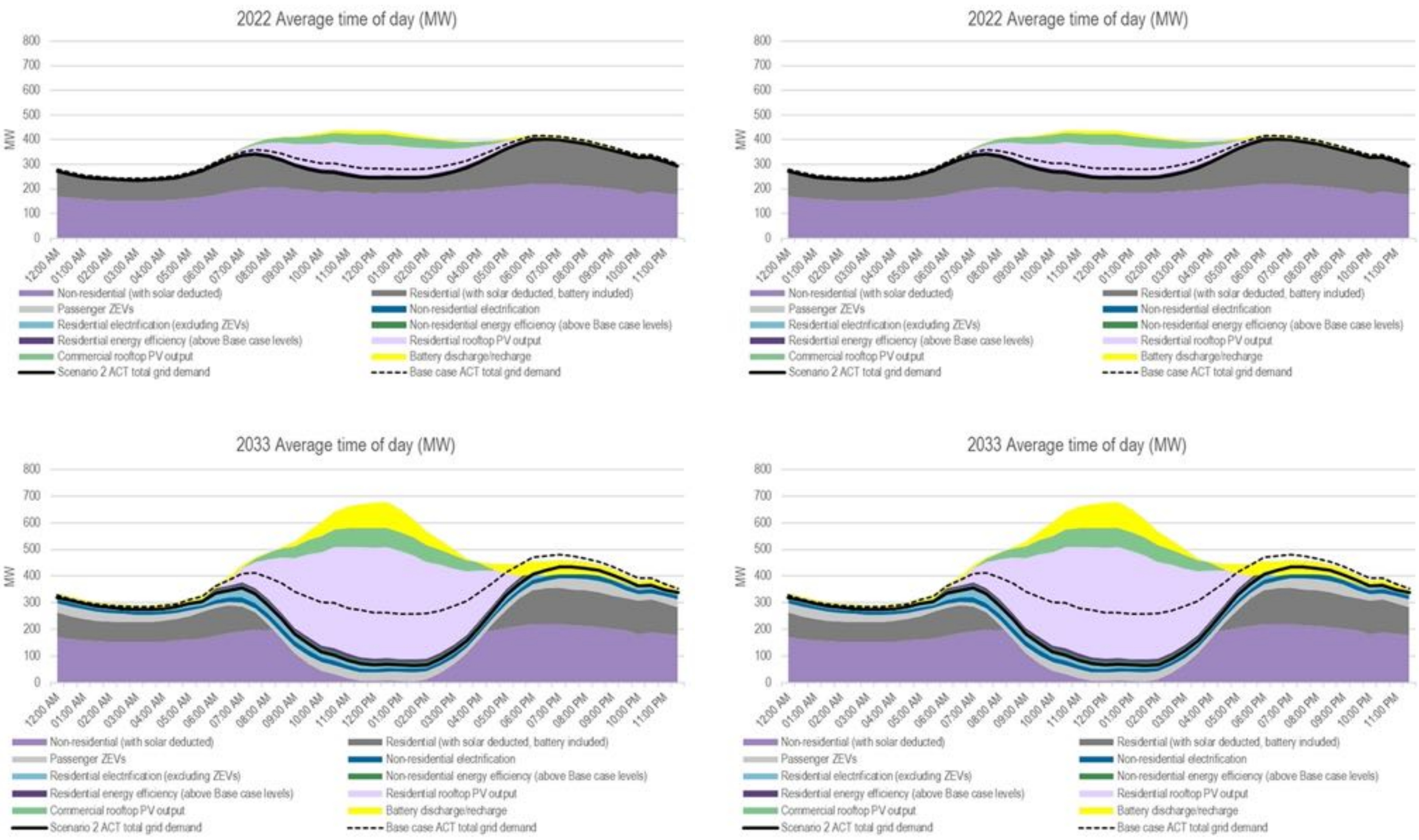
Figure 111 illustrates the impact of these technologies on the average time of day operational demand profile for 2022, 2028, 2033 and 2045.[28]

Similar to the base case, the graphs show the continuation of the 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 in the later years of the projection when uptake is high results in a noticeable reduction in evening demand (when batteries typically discharge) and an increase in daytime demands (when batteries typically recharge) compared to the base case.

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

Figure 111 Average time of day demand (MW) – for selected years – Scenario 2 vs base case



Note: V2H is included in Passenger ZEVs.

Source: ACIL Allen

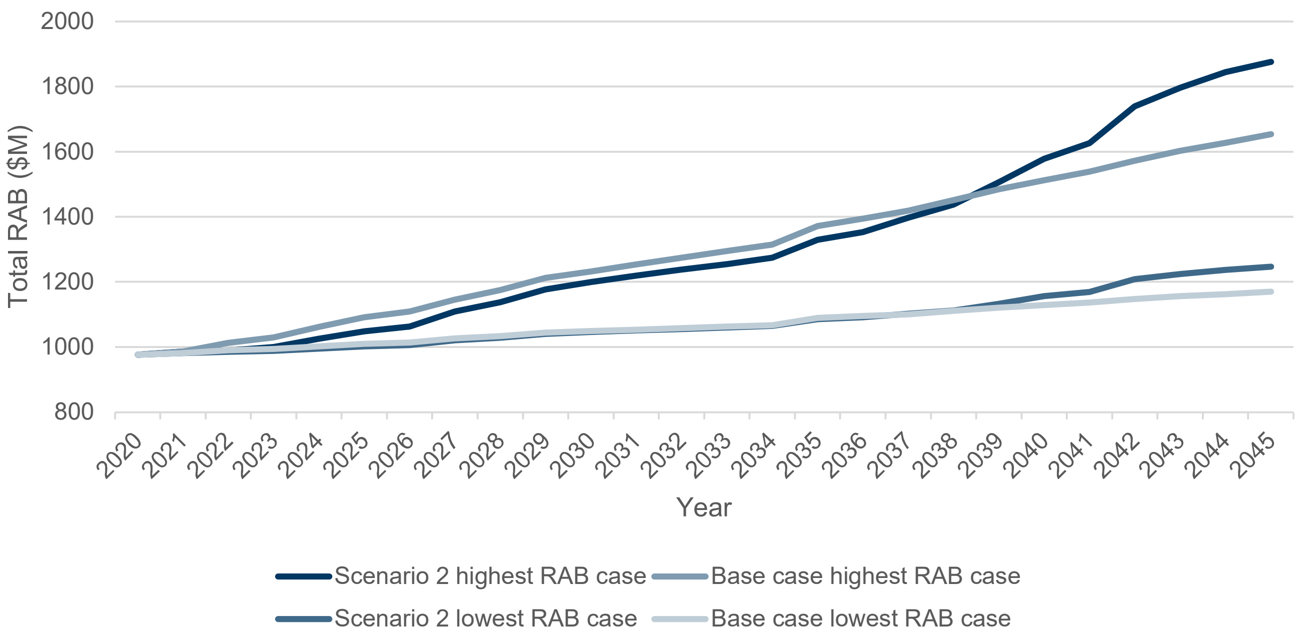
7.5 Electricity system network analysis

7.5.1 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. All modelling in all scenarios has been completed using the methodology provided in Section 4.3.

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 112 the range of the RAB between the most extreme cases is shown. All other modelling only considers the worst-case (highest) scenario RAB.

Figure 112 Comparison of highest and lowest possible RAB outcomes in Scenario 2

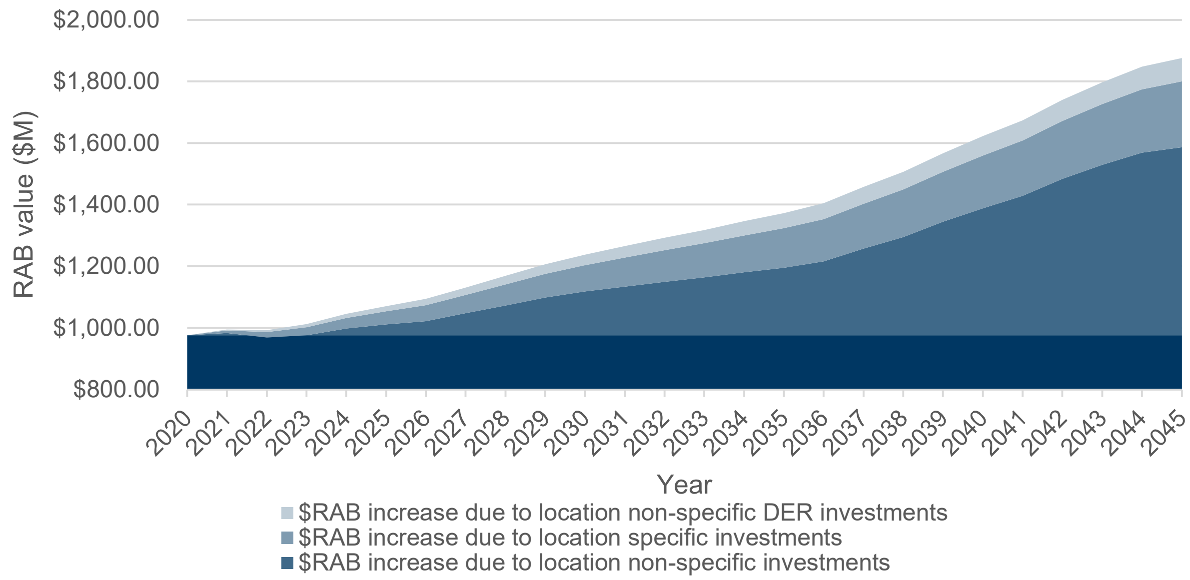


Source: GHD

The results of the modelling show that the total increase in the RAB over the period 2020-2045 is approximately $899 million as opposed to the increase in RAB over the same time in the base case of $678 million.

Figure 113 shows the change in the RAB by type of investment in the Scenario 2 forecast (Refer Section 4.3 for detailed description of investment types).

Figure 113 Cumulative change in RAB in Scenario 2 by investment type

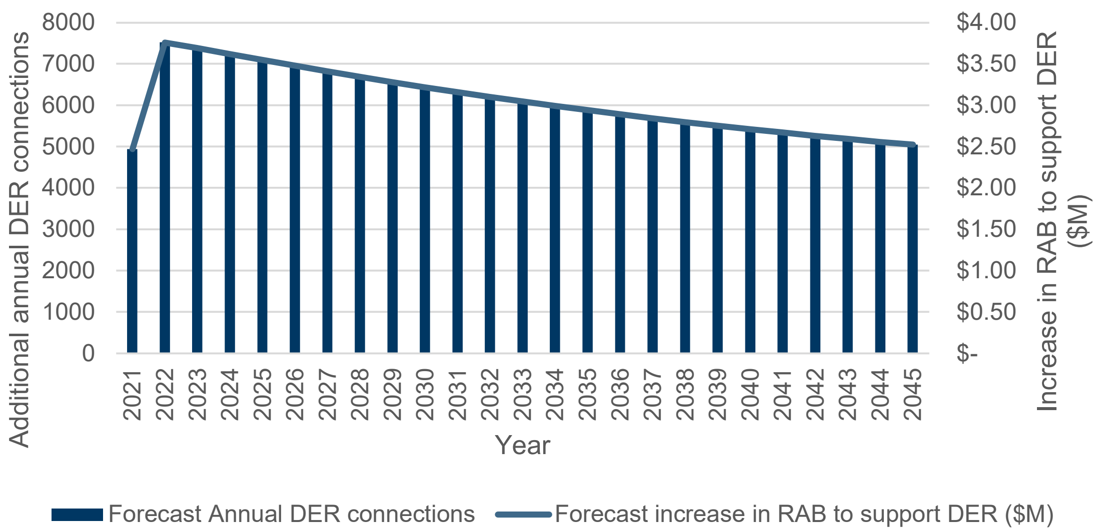


Source: GHD

Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests). Compared to the base case scenario there is an increase in location specific projects from 20 projects totalling $154 million up to 22 projects totalling $208 million (these figures include projects already underway). The detailed list of projects identified as required in Scenario 2 is shown in Table 14.

The increased uptake of DER and associated investment required to maintain quality of supply to customers is shown in Figure 114.

Figure 114 Additional DER and associated network investment forecast in Scenario 2



Source: GHD

Table 14 Forecast specific investments required in Scenario 2

KEY

+ = new or larger
↑ = moved forward
↓ = later date
x = no change

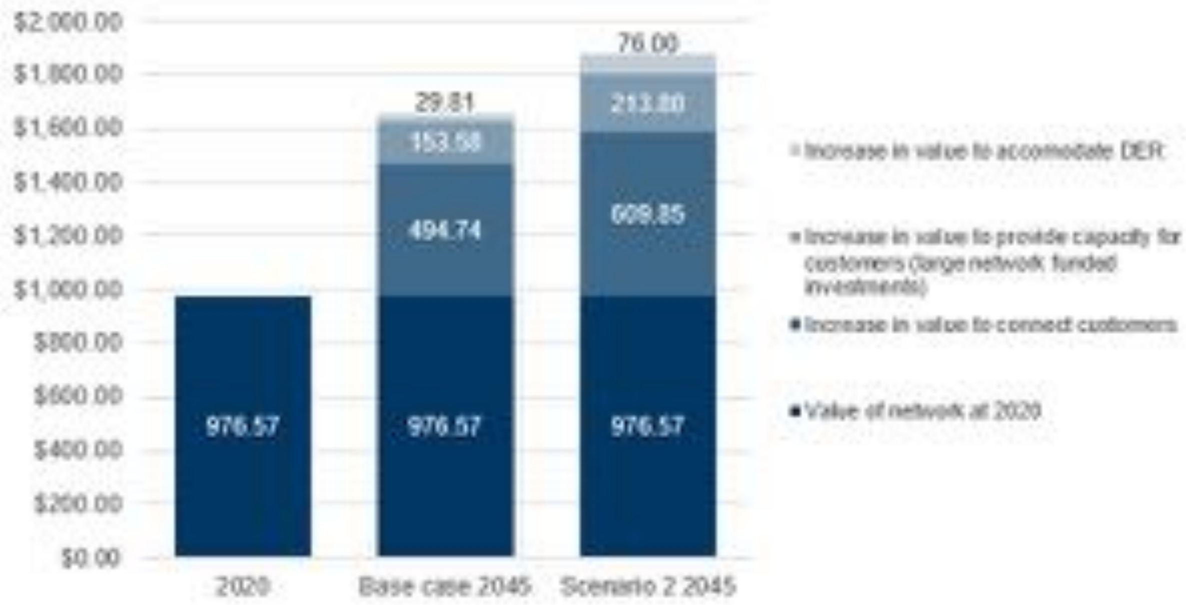
Year	Change from base case	Investment(s)	Estimated cost ($ million)
2022	x	Completion of the Molonglo battery station including first sub transmission line	13.7
2025	x	Install 3rd Transformer at Gold Creek zone substation	6.2
2027	x	Convert Molonglo battery station into zone substation by adding additional sub transmission line, transformer and feeders, plus offload more of Woden zone substation to Molonglo	17.48
2029	x	Add third transformer to Molonglo zone substation and more feeders and further offload Woden zone substation to Molonglo	10.48
2035	x	Establish new zone substation (ZS1) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Woden and Molonglo	31.22
2039	↓ x ↓	Construct 2 new distribution feeder out from City East Zone substation Construct 2 new distribution feeder out from Civic Zone substation Construct 2 new distribution feeder out from East Lake Zone substation	1.4
2040	↓ ↑ ↑ x	Construct 3rd Transformer at East Lake Zone substation Build new sub transmission line between Canberra Terminal Station and Latham zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation Construct 2 new distribution feeder out from Latham Zone substation	24.8
2041	x	Construct 2 new distribution feeder out from City East Zone substation	5.8
2042	+ ↑ x ↑ ↑	Establish new zone substation (ZS2) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Civic, City East, East Lake and Telopea Park Construct 3rd Transformer at Belconnen Zone substation Construct 2 new distribution feeder out from Belconnen Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation Construct 2 new distribution feeder out from Latham substation	54.82
2043	+	Construct 3 new distribution feeder to rearrange loads between Woden, Molonglo and ZS1	8.7
2044	+	Construct 2 new distribution feeder out from Latham Zone substation	5.8
2045	+ +	Construct 2 new distribution feeder out from Belconnen Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	11.6

Source: GHD

7.5.2 Impact on network investment

The Scenario 2 demand forecast will require investment of an additional $899 million in the network to 2045 (increasing the RAB valuation from $976.57M in 2020 to $1,876M in 2045). The relative magnitude of the growth in the various segments of the network are shown in Figure 115 below compared to the same period in the base case.

Figure 115 Change in value of the distribution asset base 2020-2045, $ million



Source: GHD

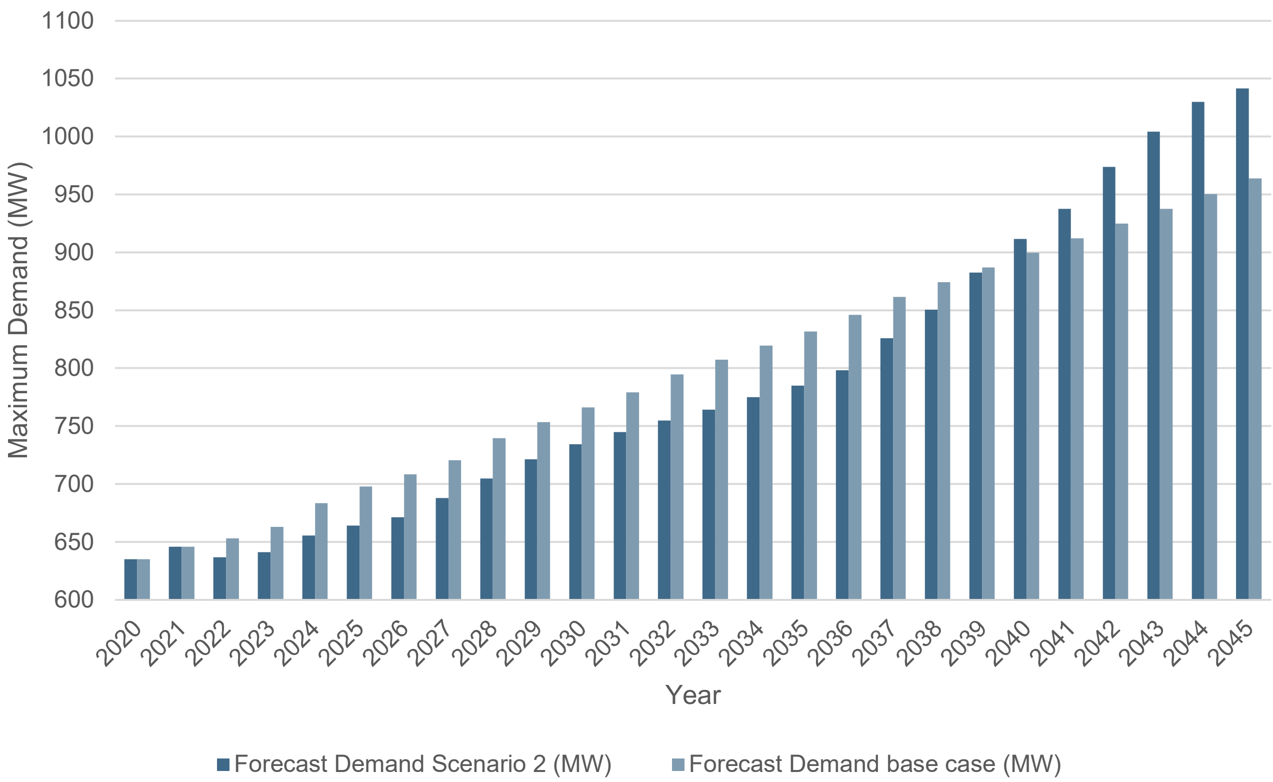
The main changes in Scenario 2 compared to the base case relate to a significantly slower growth in demand out to 2040 when the Scenario 2 demand growth then starts to exceed the base case and drive investment. The rate of growth in demand starts to really accelerate in the summer and winter from 2040 onwards leading to an 80MW difference in demand by 2045 as shown in Figure 116.

The changed growth in demand impacts on the projects required by slightly slowing initial investment in the RAB up to 2034 and with investment in the RAB increasing significantly from 2037 onwards, as shown in Figure 117. Most of the investment in this scenario is in the areas where high populations already exist (Civic, City East, East Lakes, Latham and Telopea Park) and areas where population growth is forecast (Belconnen, Gold Creek, Molonglo and Woden).

The areas where the high population already exists have large investment due to the gradual build-up of people transitioning to gas late and the moderate population growth in these areas. With the gas transition rate slightly higher than Scenario 1 there are not as many changes compared to the Scenario 1 timeframes. The areas with high population growth have investments more driven by the increase in population as the transition to gas effects a smaller pool of customers in these areas.

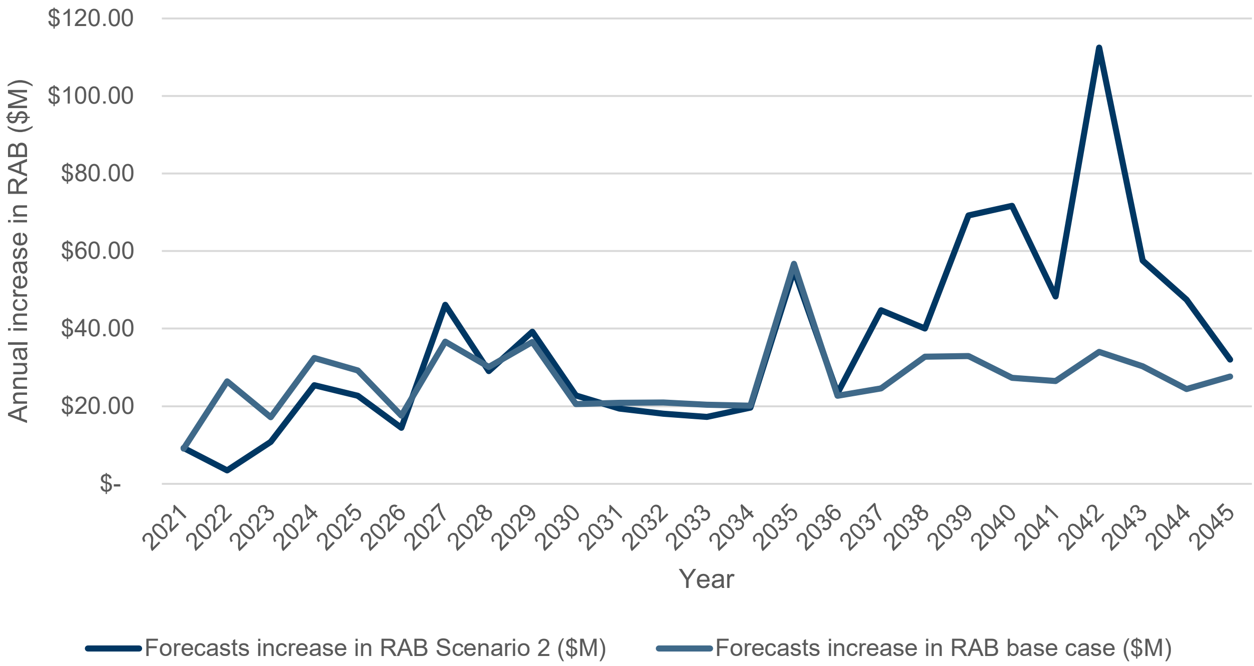
The increased uptake of solar and batteries does help keep the demand in check which delays demand related investments but does increase investment in measures to maintain supply quality. The higher rate of PV and battery installation has made the load profile slightly peakier, which has increased the location specific demand projects, but also reduced the location non-specific projects. When coupled with the higher location non-specific DER costs, this results in a slightly higher overall expenditure forecast than Scenario 1.

Figure 116 Change in network demand between Scenario 2 and base case



Source: GHD

Figure 117 Change in annual increase in RAB between Scenario 2 and the base case



Source: GHD

7.5.3 Constraints

The only real constraint identified in each of the scenarios and base case modelled is how much capital can be made available to maintain existing levels of safety, security and reliability for the forecast change in demand in the network.

That being said, in Scenario 2 an additional zone substation was identified as being required to help offload the Civic, City East, East Lake and Telopea Park areas. All of these locations are reasonably well-developed parts of the ACT which may make it difficult to identify a suitable location both in terms of land for a new substation but also in terms of being able to establish new lines in locations where lines already exist. This type of constraint could result in significant increases in expenditure beyond that which has been forecast for the project if the location of the substation ends up in a difficult location to connect.

7.6 Electricity retail bill impacts

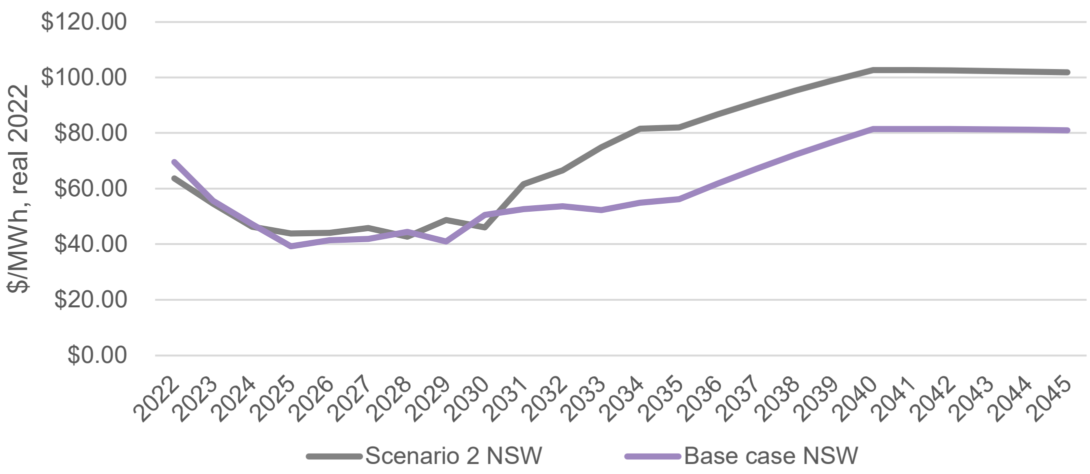
7.6.1 Wholesale component

Similar to the base case, *PowerMark* projected wholesale prices in the NSW NEM region have been used to estimate the Scenario 2 wholesale cost component of the retail bill.

In Scenario 2 is based on the wholesale scenario used in Scenario 1 but with an adjustment to demands to account for significantly higher distributed generation.

The resulting projected time-weighted spot prices for the NSW region are shown in Figure 118 below and compared to the base case. In the short- to medium-term, projected prices are similar to the base case due to the increase in distributed generation mostly offsetting higher demand from electrification. In the medium- to long-term, projected prices are higher than the base case due to higher demand from electrification and higher costs of generation, similar to Scenario 1.

Figure 118 Projected time weighted prices for NSW region ($/MWh, real 2022) – Scenario 2 vs base case



Source: ACIL Allen

7.6.2 Network component

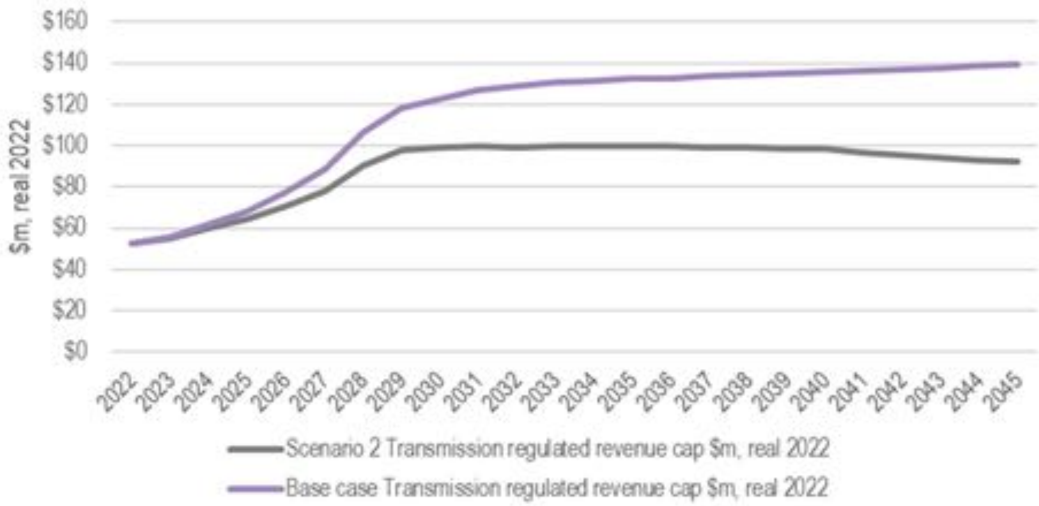
Similar to the base case, ACIL Allen has projected annual regulated revenues based on the building blocks method NUOS tariffs by customer type have been estimated using the expected weighted average revenue for the regulatory year 2021-22 in Evoenergy's pricing proposal and projected forward based on these weightings.

7.6.2.1 Transmission

Figure 119 below shows projected annual revenues recovered by Evoenergy through TUOS tariffs. Projected TUOS revenues assume significant capital expenditure by TransGrid for network augmentation under Scenario 2 associated with the ISP actionable projects and investment in new generation from electrification under Scenario 2.

Projected revenues for the ACT TUOS component are allocated using the proportion of ACT electricity consumption relative to NSW electricity consumption. Despite increased projected network augmentation of the TransGrid network under Scenario 2, compared to the base case, projected revenues apportioned to ACT customers under Scenario 2 are lower than the base case because the increase in electricity consumption across NSW (due to higher electrification) is proportionally higher than the increase in consumption in the ACT. That is, the higher transmission spending required in Scenario 2 is smeared across a larger consumption base in NSW.

Figure 119 Projected annual revenues for transmission ($ million, real 2022) – Scenario 2 vs base case

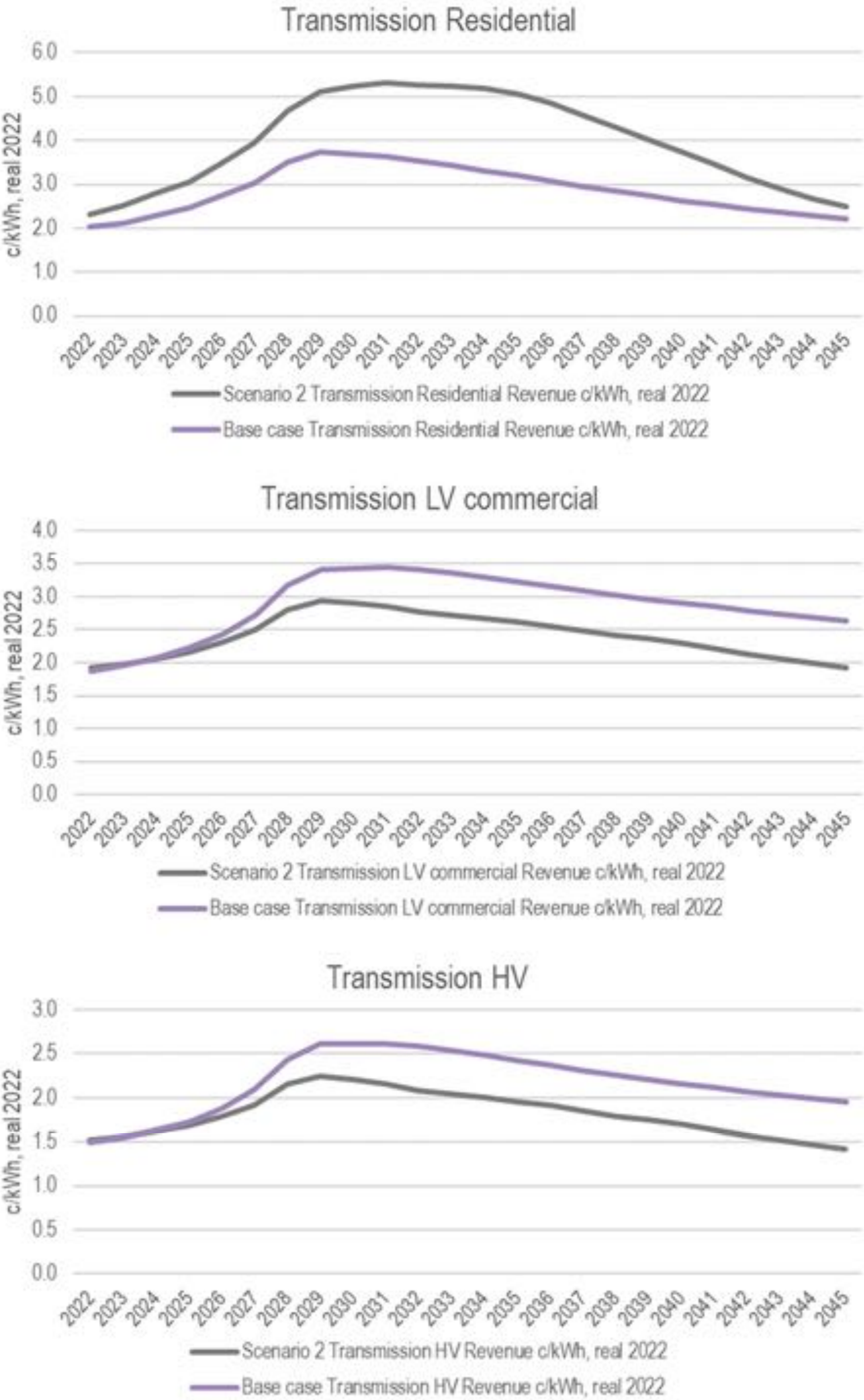


Source: AER, TransGrid, Evoenergy, ACIL Allen

Projected TUOS tariffs by customer type are shown in Figure 120 below. Similar to the base case, projected TUOS tariffs in Scenario 2 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. TUOS tariffs are higher than the base case for residential customers due to significant reduction in the residential consumption base in Scenario 2 as shown in Section 7.4.1.5.

The rate of decline in residential TUOS tariffs is projected increase from around 2035 due to the impact of higher residential consumption from passenger ZEVs in Scenario 2.

Figure 120 Projected TUOS tariff, by customer type (c/kWh, real 2022) – Scenario 2 vs base case

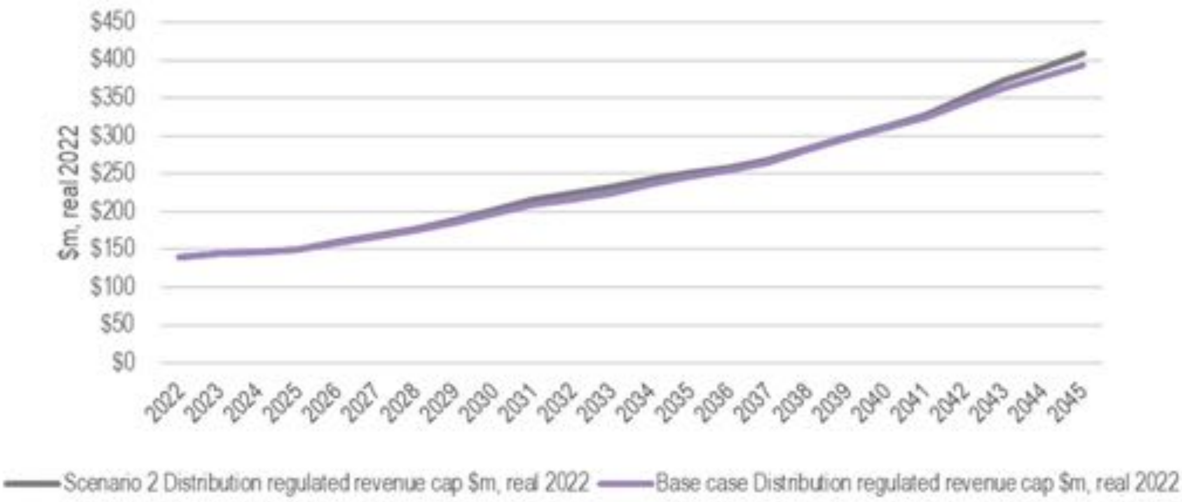


Source: AER, Evoenergy, ACIL Allen

7.6.2.2 Distribution

Similar to the base case, 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 Section 7.5) into this analysis. Figure 121 shows projected annual revenues recovered by Evoenergy through DUOS tariffs. From around 2025, Scenario 2 projected revenues are higher than the base case by around 2 per cent per annum, reflecting greater network spend in Scenario 2.

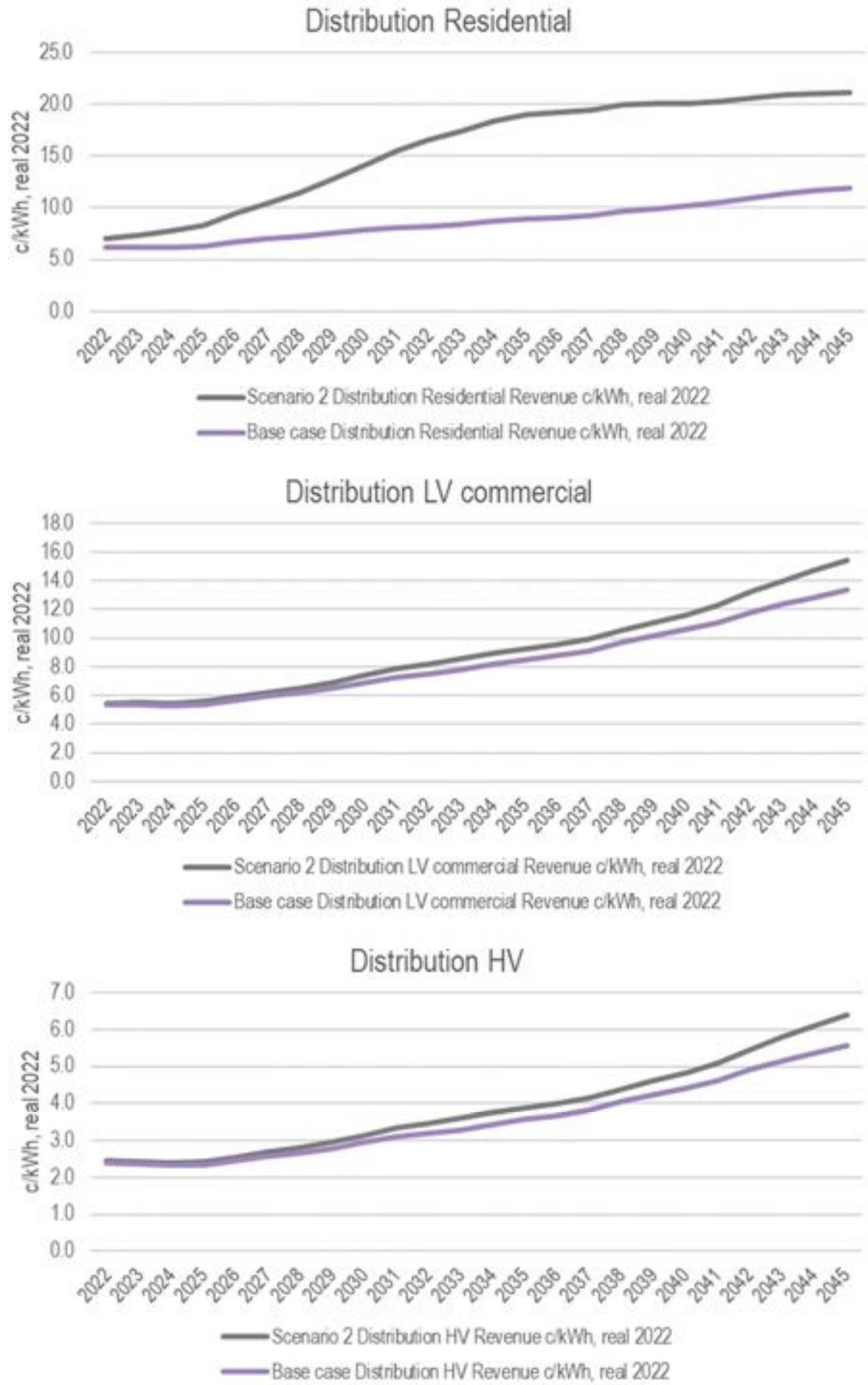
Figure 121 Projected annual revenues for distribution ($ million, real 2022) – Scenario 2 vs base case



Source: AER, Evoenergy, ACIL Allen

Projected DUOS tariffs by customer type are shown in Figure 122 below. Projected DUOS tariffs for residential and LV commercial customers are substantially higher than the base case due the smaller consumption base.

Figure 122 Projected DUOS tariff, by customer type (c/kWh, real 2022) – Scenario 2 vs base case



Source: AER, Evoenergy, ACIL Allen

7.6.2.3 Jurisdictional schemes

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

Projected large FiT payments are shown in the chart below and compared to the base case. We have assumed no change to the auction wind farms – they have the same installed capacity, timing, and contract price.

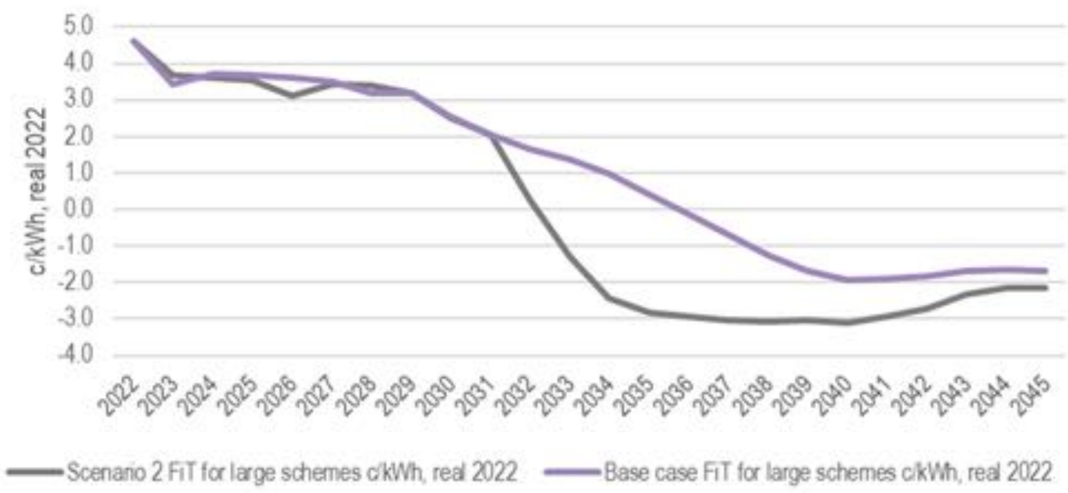
Scenario 2 lower payments are similar to the base case to around 2030 which is consistent with similar wholesale prices between this scenario and the base case. Post 2030 lower payments are largely the result of higher projected price wholesale electricity spot prices.

Similar to Scenario 1, over the period to 2030, 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.[29]

After 2030, projected wholesale electricity prices rise with the closure of several major coal fired power stations and growth in demand from projected electrification including ZEV uptake, which results in projected large FiT payments declining.

As indicated in Figure 123, large FiT payments are projected to continue to decline and by around 2033 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.

Figure 123 Projected large feed in tariff payments (c/kWh, real 2022) – Scenario 2 vs base case



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

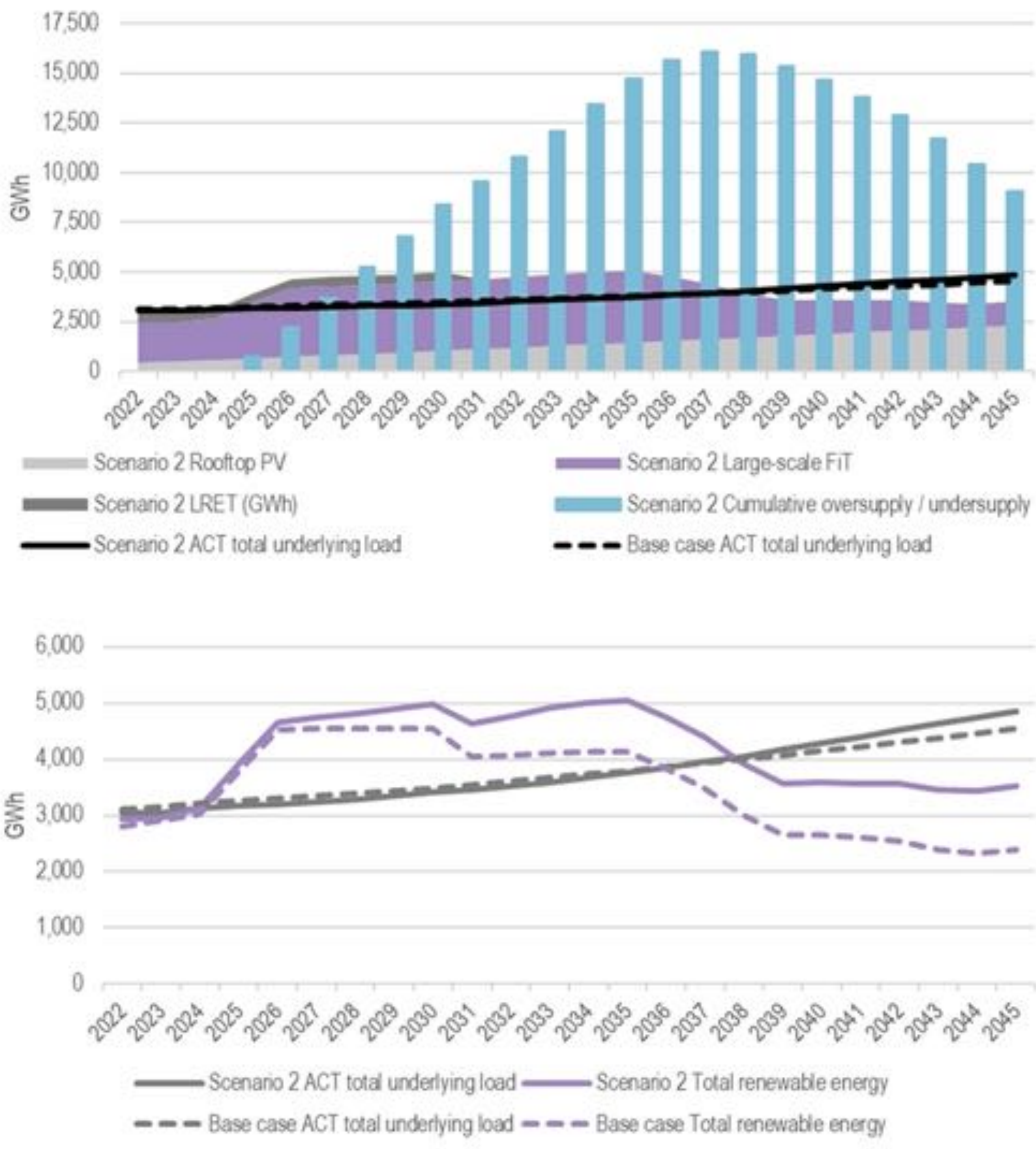
Similar to the base case, Scenario 2 incorporates the continuing purchase of renewable electricity to ensure the Territory supply is 100 per cent renewable. The projections show that the ACT will fall below the 100 per cent renewable mark from 2038, declining to around 73 per cent of underlying demand by 2045 as shown in the first

[29] Assumed new supply from large-scale grid renewable supply proposed by state-based schemes such as the NSW Roadmap and also from behind-the-meter generation.

figure below (see Figure 124). Based on the figure, the government could need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is ‘banked’ with credits carrying over to future years. These ‘banked’ credits are carried forward built into the cumulative oversupply/undersupply blue bars at the first figure below. These credits offset the need for additional purchases beyond the 2045 period.

The second figure below shows that Scenario 2 has more renewable supply in GWh terms than the base case and very similar underlying demand as the base case. As discussed above, we have assumed no change to the auction wind farms. The difference lies in how the wind farms are dispatched in Scenario 2. Similar to Scenario 1, due to higher demands across the NEM from electrification, the auction wind farms experience lower levels of curtailment than in the base case (or higher dispatch) and therefore more supply in GWh towards the target.

Figure 124 Projected contribution by category to 100% renewable energy (GWh) – Scenario 2 vs base case

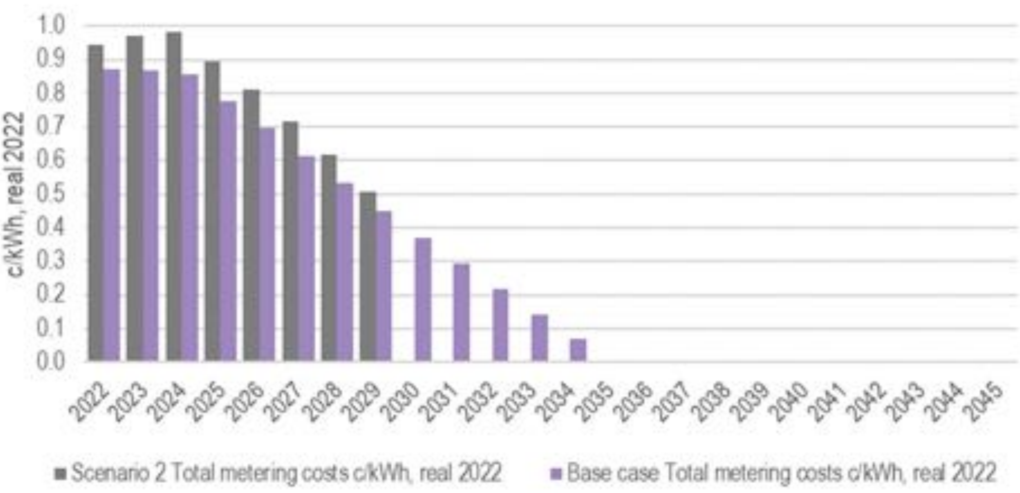


Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis:

7.6.2.4 Metering

Regulated metering charges cover the costs associated with Evoenergy's provision of regulated Type 5 and Type 6 metering services.[30] The projections illustrated at Figure 125 assume that Type 5 and Type 6 meters are phased out completely by 2030 under Scenario 2, which is earlier than the base case. Annual regulated metering costs in c/kWh are higher than the base case as a result of the lower consumption base.

Figure 125 Projected metering costs (c/kWh, real 2022) – Scenario 2 vs base case



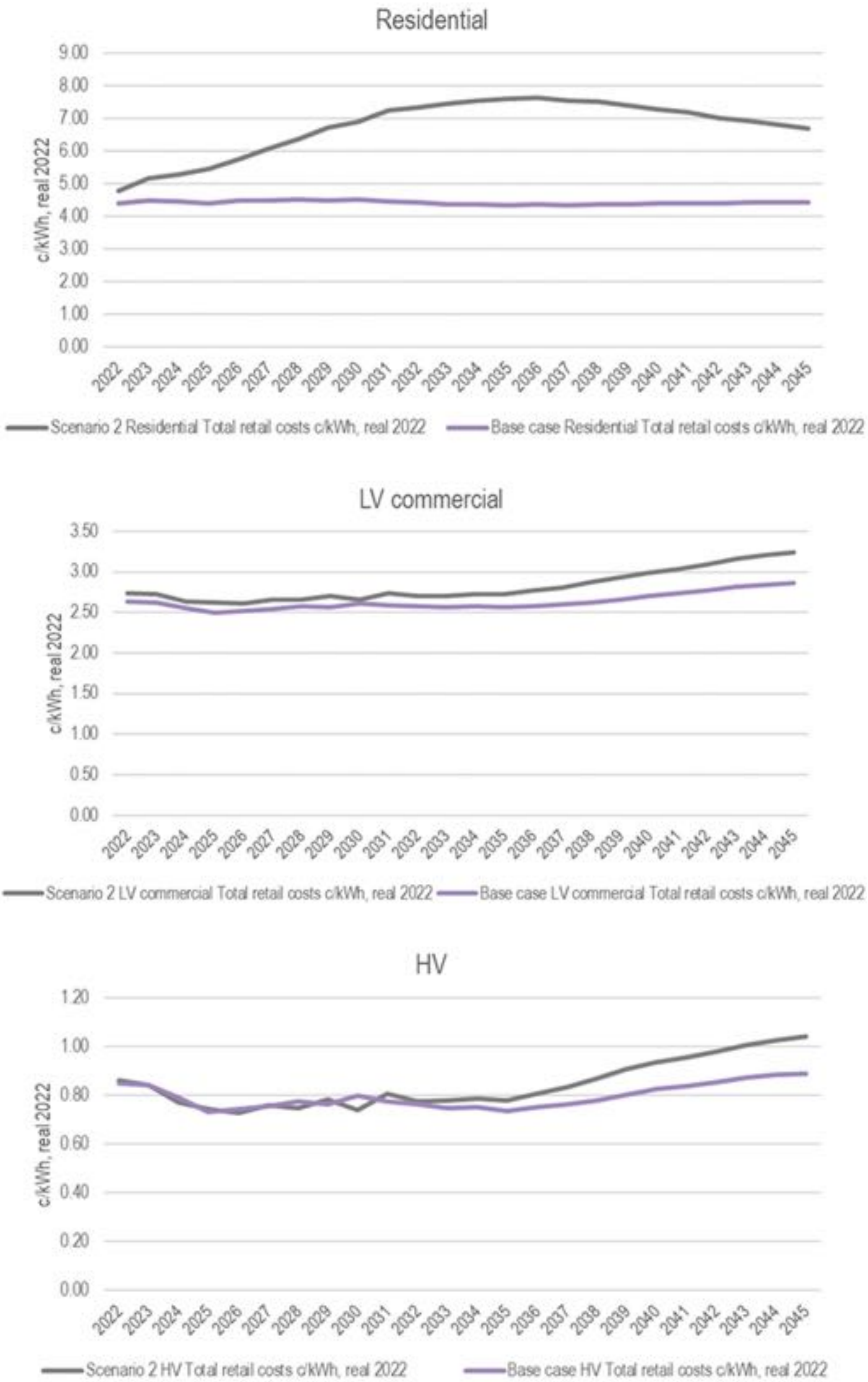
Source: ACIL Allen, AER, Evoenergy

7.6.3 Retail component

Scenario 2 projected total retail costs are generally higher than the base case, as illustrated at Figure 126, due to higher assumed smart meter costs (residential and LV customers only), higher energy efficiency scheme costs (residential and LV customers only), and higher retailer margin (all customers). The lower consumption base also drives higher retail component in c/kWh for residential customers.

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

Figure 126 Projected cost of retail component, by customer type (c/kWh, real 2022) – Scenario 2 vs base case



Source: ICRC, ACIL Allen

7.6.4 Total retail prices

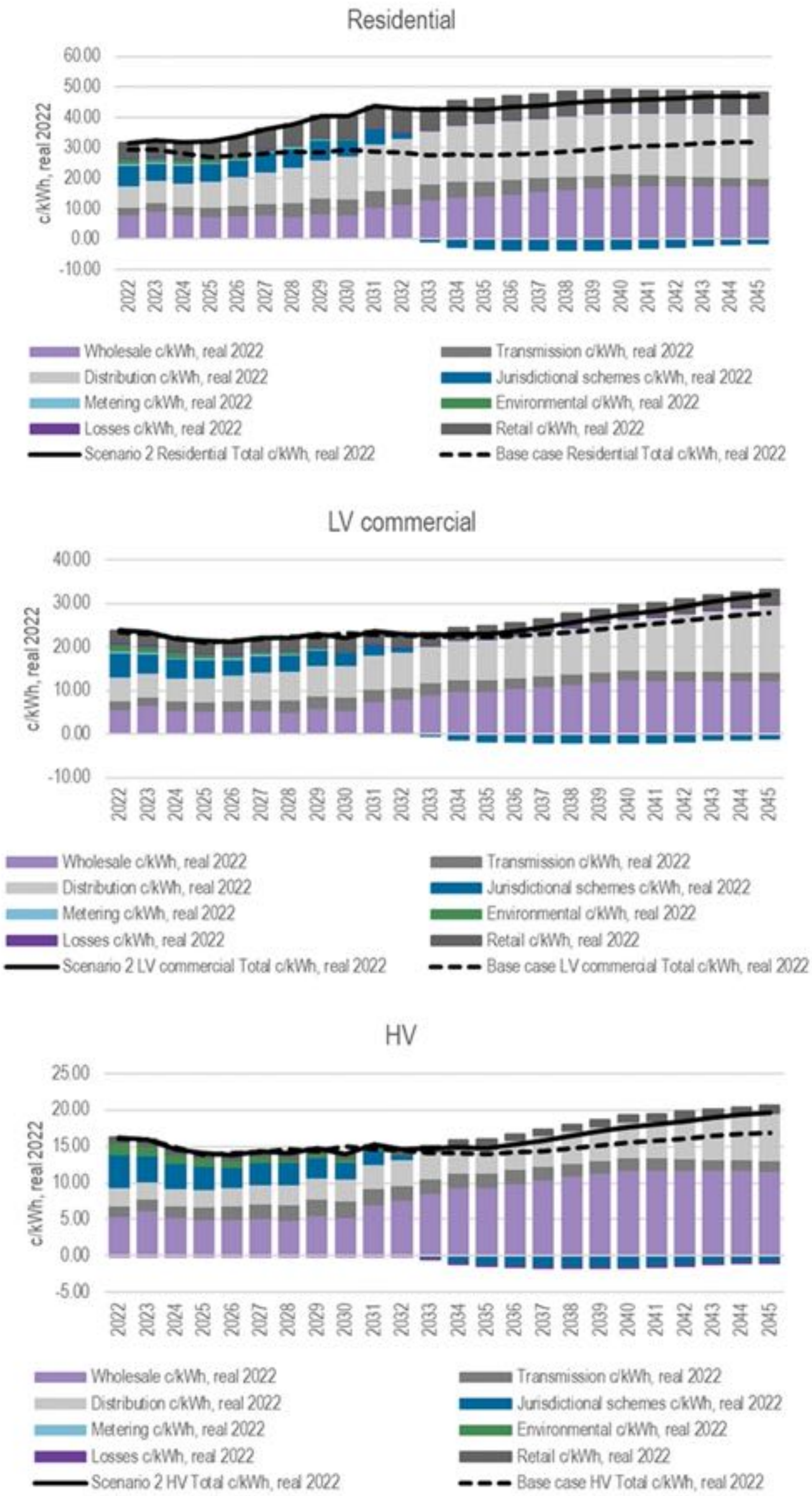
Bringing together the wholesale, network and retail components discussed in this Chapter, the projected retail prices are shown in Figure 127.

In Scenario 2, real retail prices for residential, LV commercial and HV customers are projected to increase by 48 per cent, 35 per cent and 21 per cent respectively over the period from 2022 to 2045. Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large FiT payments over the period.

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 large-scale grid supply assumed to enter the market under state-based schemes and also due to an increase in supply from behind-the-meter solar generation. From 2030, the projected wholesale component rises, reflecting the closure of several major coal fired power stations and growth in demand from projected electrification, including ZEV uptake. From around 2040, projected wholesale prices are capped at the long-run cost of new entrant supply.
- Network component (transmission) – is projected to rise over the period to 2030 given projected capital expenditure to support major transmission network augmentations. After 2030, accelerated consumption growth in the broader NSW region is projected to surpass revenue growth, resulting in a declining transmission component.
- Network component (distribution) – is projected to grow significantly over the period to 2035 given projected capital expenditure to support major distribution network augmentations and projected declining consumption. After 2035, projected consumption growth returns due to ZEV uptake, resulting in slower projected growth in the distribution component for residential and low voltage customers. High voltage customer distribution tariffs are projected to grow at a consistent rate across the entire period due to projected flat consumption from this customer class.
- 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 around 2033, the large FiT is expected to return net revenues to customers.
- Network component (metering) – is projected to decline over the period to 2030 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 customers, this component is projected increase over the period to 2035 as the consumption base falls, and then decline as consumption increases again from 2035. For high voltage customers, retail costs are stable until around 2035 and then increase due to the retailer margin.

Figure 127 Projected retail prices in the ACT, by component, by customer type (c/kWh, real 2022) – Scenario 2 vs base case



Source: ACIL Allen

7.6.5 Retail bill

We have estimated projected retail bills for different customers as shown in Figure 128 by multiplying the projected retail price by the projected average consumption per customer.[31]

- projected average consumption per customer declines over the period to around 2035 because of the projected increase in penetration of rooftop solar PV
- after 2035, projected average consumption per residential customer rises as a result of electrification
  - for LV commercial customers, projected average consumption declines gradually across the entire projection period due to the impact of strong energy efficiency improvements which offset the impact of natural gas transition, while for HV commercial customers, projected average consumption rises from 2026 as a result of the impact of natural gas transition.

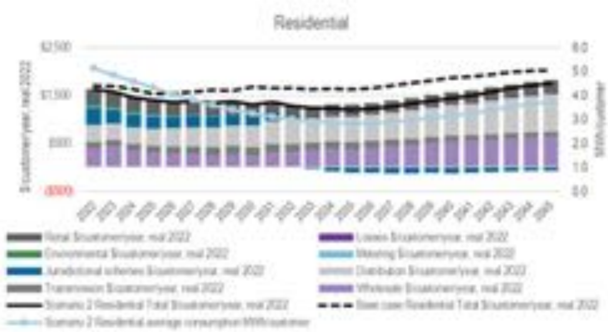
Over the period to 2035, projected retail bills for residential, LV commercial and HV customers are projected to decline in real terms by 26 per cent, six per cent and 10 per cent, respectively. This is the result of the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes offsetting projected increase in wholesale costs and distribution network costs.

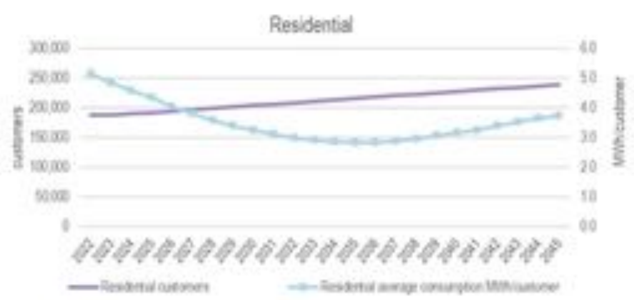
Over the period from 2035 to 2045, projected retail bills for residential, LV commercial and HV customers increase by 45 per cent, 32 per cent and 32 per cent, respectively. These increases reflect the projected increase in wholesale and distribution network costs, which are only partially offset by the projected decline in transmission network costs.

In Scenario 2, the retail bills for residential, LV commercial and HV customers (in real terms) are projected to increase by 7 per cent, 24 per cent and 20 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 19 per cent, 19 per cent and 12 per cent respectively).

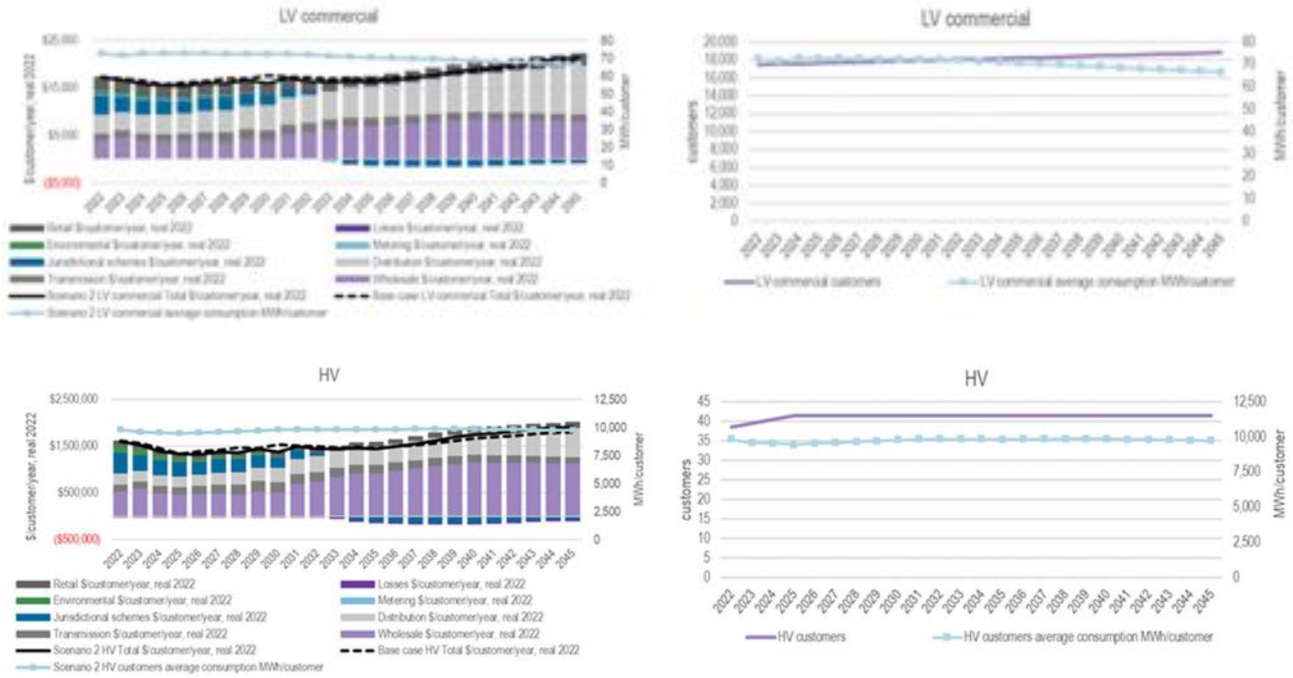
At the start of the projection period, wholesale costs comprise around 30 per cent of the residential bill, distribution costs 20 per cent, and large FiT costs 20 per cent. By 2045, wholesale costs grow to 40 per cent of the residential bill, distribution costs grow to 40 per cent and large FiT costs decline to around three per cent. A similar trend is projected for the low and high voltage commercial bills.

Figure 128 ***Projected retail bill (left chart), by component, by customer type ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS) – Scenario 2 vs base case; Projected customer numbers (right chart)***





[31] 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.



Source: ACIL Allen

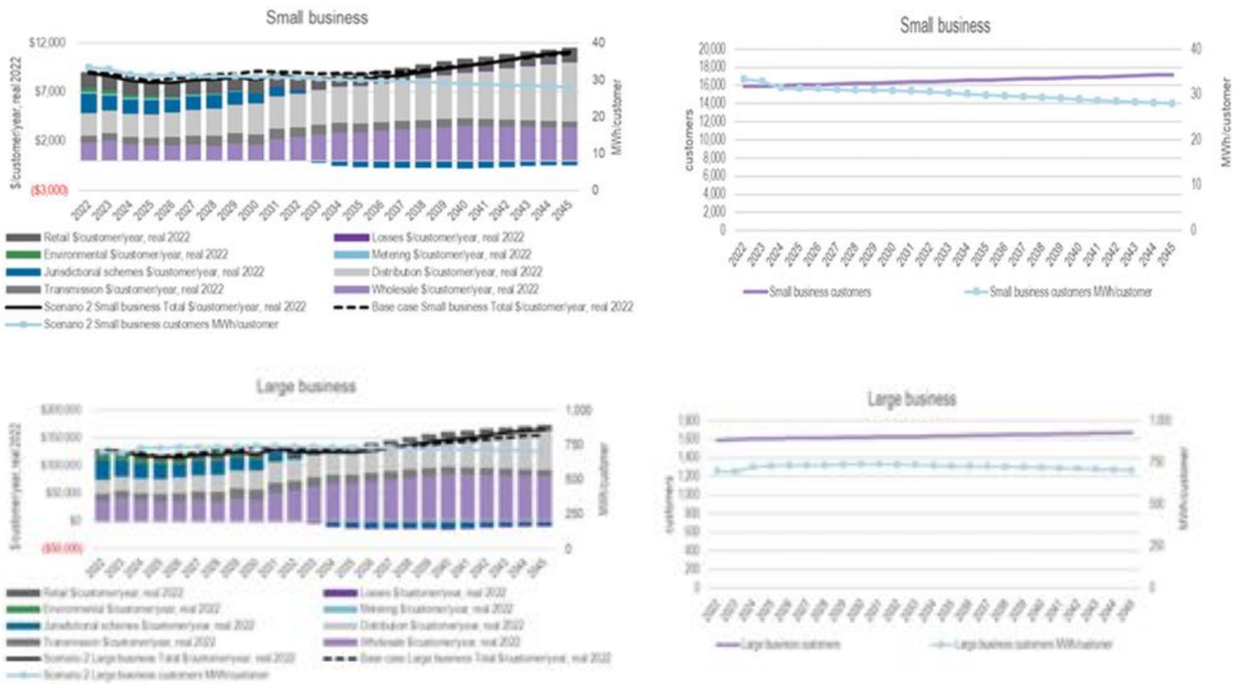
7.6.5.1 Retail bill using AER customer classes

This section discusses projected retail bills in Scenario 2 based on AER categories. Figure 129 shows projected retail bills for small and large business customers based on the AER categories. Under both the Evoenergy and AER classifications residential customers are identical.

In Scenario 2, the retail bills for small and large business customers (in real terms) are projected to increase by 24 per cent and 28 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 20 per cent and 21 per cent respectively). While projected bills in 2045 are very similar between the base case and Scenario 2, the pathway to this point is very different. In Scenario 2, projected average consumption per customer is lower than the base case, which offsets the higher costs to the customer (in c/kWh).

At the start of the projection period, wholesale costs comprise around 20 per cent of the small business bill, distribution costs 27 per cent, and large FiT costs 23 per cent. By 2045, wholesale costs grow to 30 per cent of the residential bill, distribution costs grow to 55 per cent and large FiT costs decline to around three per cent. A similar trend is projected for the large business bill, except that in 2045 wholesale costs grow to a larger proportion (50 per cent) and distribution costs to a lesser proportion (45 per cent) of the total bill.

Figure 129 ***Projected retail bill (left chart), by component, of small and large business customers ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS) ; Projected customer numbers (right chart)***



Source: ACIL Allen

7.7 Costs and benefits to the ACT economy

As per Scenario 1, the transition of the ACT energy system under the alternative decarbonisation scenarios will come with a range of costs and benefits compared to the base case. This section presents the change in costs related to increasing renewable electricity usage, along with a range of benefits associated with reductions in gas, petrol and diesel usage and their associated costs in Scenario 2. In addition, there will be extra reduction in GHG emissions under the alternative decarbonisation scenarios compared to the base case.

Table 15 summarises the various direct costs and benefits of Scenario 2 compared to the base case.

7.7.1 Costs

In total, there are expected to be an additional $1.5 billion in costs (with a net present value of $497 million, using a seven per cent real discount rate (NPV7)) associated with the increased electricity usage. Compared to the base case, this comprises:

- $742 million (or NPV7 of $135 million) of additional capital expenses associated with upgrading the ACT electricity network (taken from the RAB figures – worst-case estimates).
- $616 million (or NPV7 of $264 million) of additional capital expenses associated with installing large scale and community batteries (with capital costs in each year taken from *PowerMark*).
- $936 million (or NPV7 of $508 million) of additional capital expenses associated with behind the meter residential and commercial rooftop PV systems and battery storage (with capital costs in each year taken from *PowerMark*).
- $951 million (or NPV7 of $405 million) of additional vehicle purchase costs associated with buying ZEVs instead of conventional and hybrid ICE vehicles. (Note: this upfront cost is offset by reduced petrol and diesel purchases which are included in (10) below.)
- $4.5 million (or NPV7 of $1.4 million) of additional purchase and installation costs for converting gas appliances to electric.
- -$1,727 million (or NPV7 of -$497 million) of additional retail electricity costs for consumers. That is, in Scenario 2, there is a net reduction in the total cost of electricity purchased from the grid by consumers. This is driven by the large uptake of behind the meter generation and storage. For consistency in presentation with the other scenarios, this electricity line item has been grouped with the other electricity costs.
- No costing of the energy efficiency improvements has been undertaken, but the benefits are included in (6). Scenario 2: *Decentralisation is king*, assumes strong government support for energy efficiency, and rapid improvements in efficiency standards, which leads to moderate/high energy savings of around an additional 800 GWh by 2045 (315 GWh or around 65 per cent more energy savings than the base case).

7.7.2 Benefits

In terms of benefits, Scenario 2 is expected to save ACT consumers $2.3 billion (or NPV7 of $842 million) in gas and fuel costs compared to the base case. This comprises savings of:

- $5.8 million (or NPV7 of $1.9 million) of reduced capital expenditures related to maintaining the gas network (from the assumptions underlying the retail pricing model for the gas market projections).

- $156 million (or NPV7 of $52 million) of reduced gas purchases by ACT consumers.
- $1,923 million (or NPV7 of $708 million) of reduced petrol and diesel expenses related to running additional ZEVs in Scenario 2 instead of ICE vehicles in the base case.
- $218 million (or NPV7 of $80 million) of reduced human health costs associated with a reduction in noxious emissions from ICE vehicles as a result of the increased uptake of ZEVs in Scenario 2 compared to the base case.

7.7.3 Net cost and GHG emissions

The net change in the direct costs of Scenario 2 compared to the base case is estimated to be -$780 million (or NPV7 of -$344 million). That is, the projected calculated benefits outweigh the calculated costs included here. In reality, this scenario also relies on significant changes in energy efficiency which have not been costed as part of this analysis.

In addition to the benefits discussed above, Scenario 2 will also result in a reduction of GHG emissions over the period to 2045 of 2,077 kt CO_2-e compared to the base case, comprising:

- A reduction of 1,690 kt CO_2-e associated with reduced fuel use in passenger vehicles. This is based on the emission intensity of fuels as per DITRDC (2021).
- A reduction of 388 kt CO_2-e associated with reduced gas use in the ACT (taken from the gas market projections).
- No change in GHG emissions associated with the additional electricity consumed (as per Scenarios 1 and 3).

7.7.4 Implied emissions abatement cost

Comparing the net cost of Scenario 2 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. As per (E) in Table 15, the total undiscounted net cost of Scenario 2 implies a GHG emission abatement cost of -$375/t CO_2-e, with an NPV7 abatement cost of -$166/t CO_2-e.

Table 15 Costs and benefits of Scenario 2, relative to the base case

		Total	NPV4	NPV7	NPV10
	Description	real A$m	real A$m	real A$m	real A$m
	COSTS				
	Additional CAPEX (relative to the base case)				
1	Electricity network and distribution	741.5	249.5	134.5	45.4
2	Grid connected batteries	616.0	349.7	263.7	210.8
3	Behind the meter PV and batteries	936.0	608.7	507.9	395.8

		Total	NPV4	NPV7	NPV10
	Description	real A$m	real A$m	real A$m	real A$m
4	ZEVs cost premium	951.2	536.5	404.6	312.4
5	Appliances (net)	4.5	2.1	1.4	0.9
6	Net additional retail electricity cost	-1,726.7	-1,044.8	-814.8	-661.1
7	Energy efficiency capital expenses	*Not costed*	*Not costed*	*Not costed*	*Not costed*
A	Total change in costs [=1+2+3+4+5+6+7]	1,522.6	701.8	497.3	304.3
	BENEFITS				
8	Reduced gas network and distribution CAPEX	5.8	2.6	1.9	1.2
9	Net reduction in retail gas cost	155.6	68.0	52.1	32.4
10	Reduced vehicle retail fuel cost	1,922.7	979.4	707.6	509.3
11	Reduced vehicle human health costs	218.4	110.9	80.1	57.4
B	Total benefits (excl. GHG) [=8+9+10+11]	2,302.5	1,161.0	841.6	600.3
C	Net change in costs (relative to the base case) [=A-B]	-780.2	-459.1	-344.3	-296.1
	REDUCTION IN GHG EMISSIONS	kt CO_2-e	kt CO_2-e	kt CO_2-e	kt CO_2-e
12	Reduced vehicle fuel use	1,689.5	1,689.5	1,689.5	1,689.5
13	Reduced gas use	387.7	387.7	387.7	387.7
14	Changes in electricity consumption	0	0	0	0
D	Total reduction in GHG emissions [=12+13+14]	2,077.3	2,077.3	2,077.3	2,077.3
		$/t CO_2-e	$/t CO_2-e	$/t CO_2-e	$/t CO_2-e
E	Implied abatement cost [=C/(D/1000)]	-375.5	-221.0	-165.8	-142.5

Note: All dollars are in real 2022 terms. Pricing for (6) Net electricity costs, excludes the pass through of capital expenditure (1) to customers. The additional cost of (2) Grid connected batteries, includes additional annual fixed operating and maintenance costs. There is no change in emissions from electricity given the policy of purchasing 100% renewable electricity.

Source: ACIL Allen

7.8 ACT economy-wide analysis

This Section presents the projected macroeconomic impacts using CGE modelling (as detailed in the discussion at Scenario 1).

7.8.1 Macroeconomic impacts

Figure 130 presents the annual macroeconomic and employment impacts of Scenario 2, relative to the base case while Table 16 presents the cumulative impacts over the period to 2045.

Table 16 Total macroeconomic impacts of Scenario 2, relative to the base case

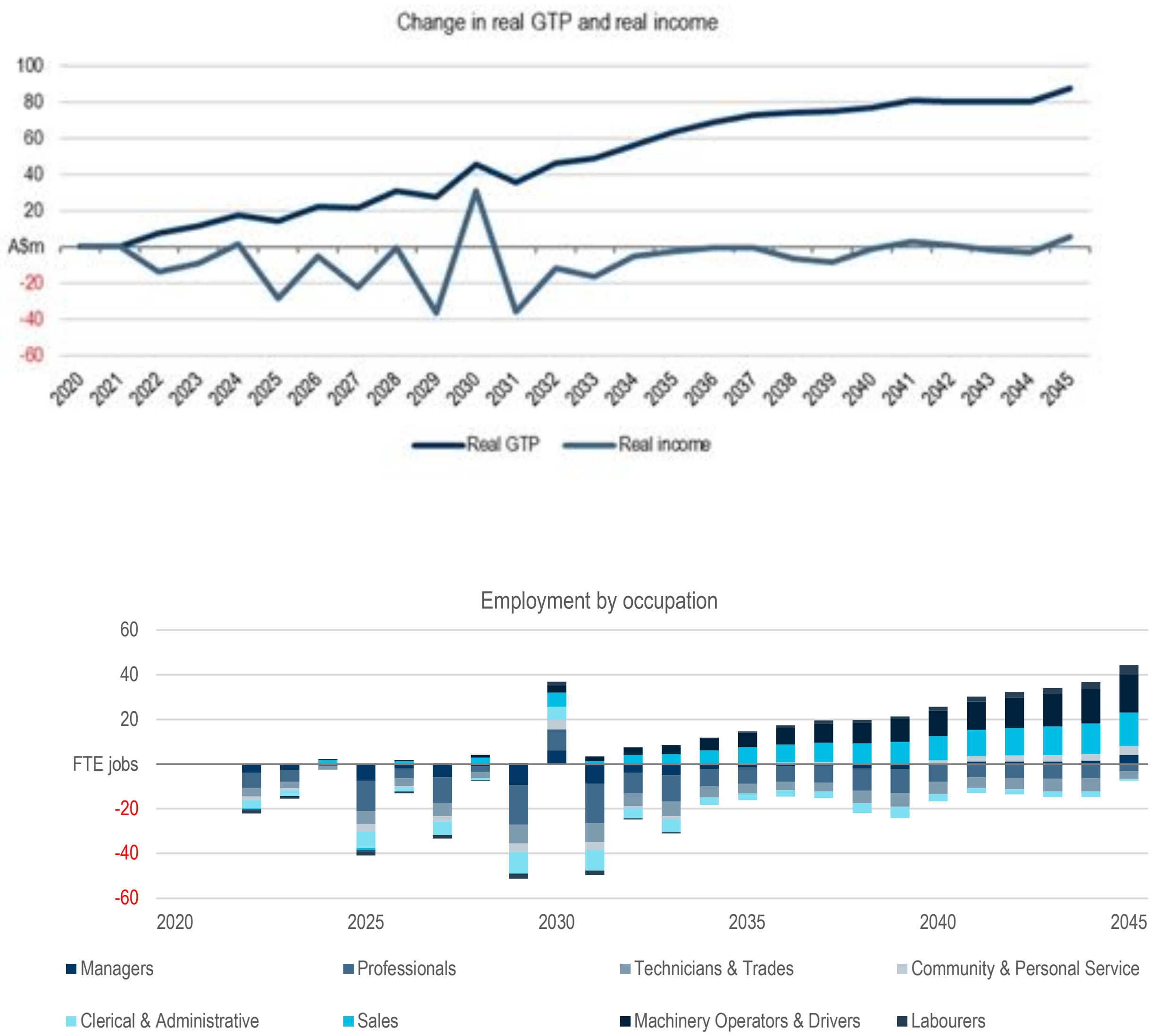
	Total	NPV4	NPV7	NPV10
	real A$m	real A$m	real A$m	real A$m
Real economic output (GTP)	1,223.6	775.1	451.1	315.4
Real income	-165.4	-132.7	-102.1	-85.6
	Total	Annual average		
	FTE jobs	FTE jobs		
Employment	-109	-4		

Note: All dollars are in real 2022 terms.
Source: ACIL Allen

There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, electricity prices and volumes, gas prices and volumes, and vehicle fuel purchases. In total, over the period to 2045 the cumulative difference of Scenario 2 relative to the base case is:

- +$1,224 million (or NPV7 of +$451 million) increase in the real GTP of the ACT, driven largely by the stimulus benefit of the cheaper electricity and energy savings from energy efficiency improvements
- -$165 million (or NPV7 of -$102 million) change in the real income of ACT residents
- -109 FTE employee years of employment (annual average change of -4 FTE jobs a year) in line with the higher real income.

Figure 130 Annual macroeconomic impacts of Scenario 2, relative to the base case



Source: ACIL Allen

8. Scenario 3: *Policy drives change*

This Chapter sets out a summary of the Scenario 3 techno-economic modelling results.

8.1 Scenario description

The *Policy drives change* 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.

The key variables for *Scenario 3 Policy drives change* are detailed at Table 17.

Table 17 Scenario 3 Policy drives change: key variables

Variable	Description	*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))	Gas demand reduces to zero by 2035
Rate of gas household electrification	Percentage of existing gas customers that switch to electricity each year	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	95%
Residential batteries uptake	Percentage of installed domestic PV systems with batteries	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)	95%
Batteries	Amount of large-scale battery storage installed by 2045	860MW
	Amount of Neighbourhood/community battery storage installed by 2045	400MW
Energy efficiency	Level of energy efficiency (low/moderate/high) Annual energy savings (GWh) in 2045 Percentage change from base case.	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’ scenario.
Electric vehicle uptake (by 2045)	Percentage of the fleet that is EVs by 2045 (this includes autonomous vehicles (Avs) – all assumed to be electric)	68%

Variable	Description	*Policy drives change*
Use of EVs for V2H and V2G	Percentage of EVs that are used as ‘batteries’ to supply homes (V2H) or the grid (V2G) (based on the ‘hydrogen superPower’ scenario in the latest ISP assumptions workbook)	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	Medium

8.2 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 (decommissioning costs are not factored into the modelling). 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 ZEVs and discourage the sales of new ICE vehicles after 2025 causes the sales of ZEVs 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.

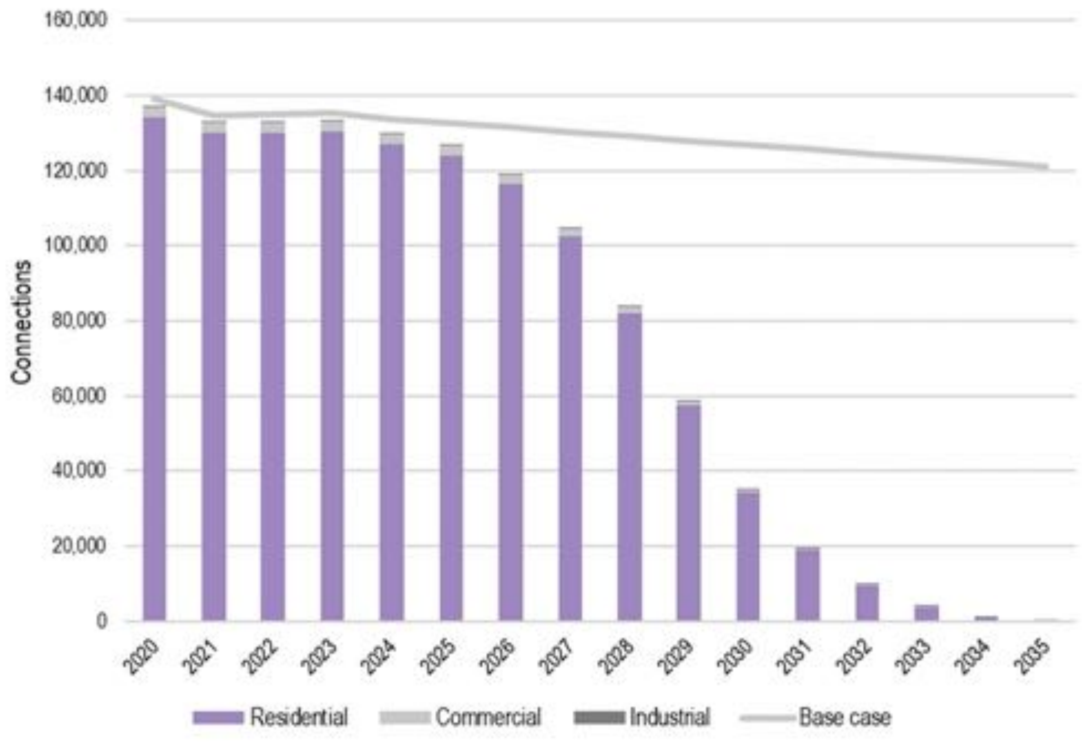
The number of ZEVs used for V2H and V2G slowly increases over time, say 10 per cent of the EV fleet in 2030, 20 per cent by 2035 and 40 per cent by 2045.

8.3 Gas market projections

8.3.1 Connections

Projected gas connections in the ACT under Scenario 3 are provided at Figure 131. This scenario assumes gas connections are effectively zero by 2035. Total connections in the ACT (excluding Queanbeyan) drop from around 140,000 in 2020 to zero in 2035. Over the forecast period, connections fall dramatically from 2026. To achieve the goal of zero connections by 2035, this scenario projects that 25 per cent of residential and commercial customers will replace their gas appliances with electrical appliances from 2026 to 2030. From 2031, two-thirds of gas appliances are replaced with electrical appliances each year to 2035. This is a much higher rate than in any other scenario presented. This profile represents a scenario where strong government policy and significant financial incentives rapidly transition gas customers to the electricity grid.

Figure 131 ***Projected gas connections, ACT – Scenario 3 vs base case***



Source: ACIL Allen

8.3.1.1 Consumption per connection

Residential, commercial and industrial

Residential consumption per connection is expected to drop from levels around 33 GJ per annum to 20 GJ per annum by 2030. Commercial consumption per connection is assumed to drop from levels around 520 GJ per annum to levels around 330 GJ per annum in 2030. Industrial consumption is expected to drop from around 30,000 GJ per annum to levels around 24,000 GJ per annum by 2030. These falling consumption rates are broadly in line with the drop in connections and not dissimilar to those in Scenarios 1 and 2.

Beyond 2030 the consumption of natural gas falls far more quickly in response to rising prices and given the imminent closure of the network in 2035 (by which stage the last few connections disappear). The scenario assumes that the network exists until the final connections are disconnected and switched to electricity (even though it may not be economically viable over the last 2-3 years). Under scenarios 1 and 2, it is likely that the decommissioning of the network would occur in phases where certain suburb clusters are shut down before others. While a similar pattern could be pursued under Scenario 3, the drastic reductions in connections and consumption over a short period, will make phased decommissioning challenging.

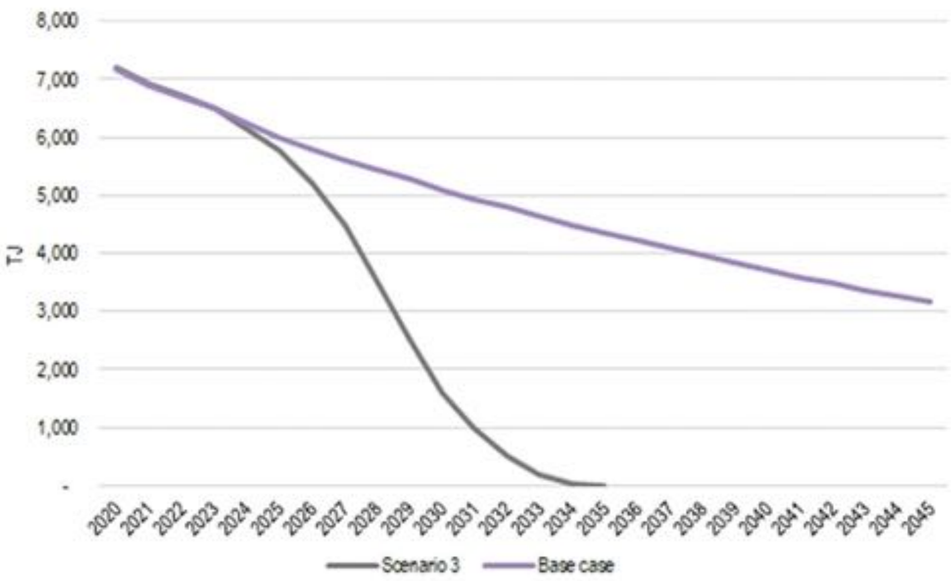
However, the closure of the gas network is unlikely to herald the end of gas usage in the ACT. There will be some residual gas use by customers unable to electrify. Some industrial customers may need gas as a feedstock or electric equipment options may be limited/unavailable. Remnants of the natural gas network may be used to supply these customers, especially if they are located in the same geographical area. However, this will depend on the financial and commercial position of Evoenergy, or an alternate owner (further analysis would be required to determine the feasibility of this option).

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 (either green gas or liquified petroleum gas (LPG) with 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). 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, appliance and technology capabilities, and may be site specific including on-site generation. Where green gas is not a practicable alternative, offsets will need to be purchased to deliver on the Territory's net zero goals. As discussed in Section 6.3.2.1, offsets are likely be valued at the cost of hydrogen or biogas at that time. The cost of hydrogen is expected to be around $3/kg in the 2030s, which translates to a figure of $24/GJ. By 2040, its estimated that hydrogen could be around $2/kg, or $16/GJ.

8.3.1.2 Projected total consumption

Total consumption in the ACT to drop from levels around 7,000 TJ currently to zero in 2035. The majority of the decline starts post 2026. This is compared with the base case in Figure 132. This scenario represents a case where consumption and connections begin a sharp decline post the current access arrangement period. Strong policy and regulatory drivers will be required to achieve this scenario outcome. The incentive for gas customers to switch must be incredibly high or regulations introduced to prohibit gas appliances (with a transition period given for customers to switch to electrical appliances). Switching rates increase from levels around 4 per cent from 2020 to 2025 to levels around 25 per cent in the period from 2025 to 2030. From 2030 onwards, this increases to almost 70 per cent. Therefore, after the current access arrangement period ends in 2026, switching out of gas appliances to electricity increases to around 1 in 4 connections moving to electricity to 2035, then to a rate where more than 1 in 2 households are moving to electricity.

Figure 132 Projected total gas consumption, ACT – Scenario 3 vs base case



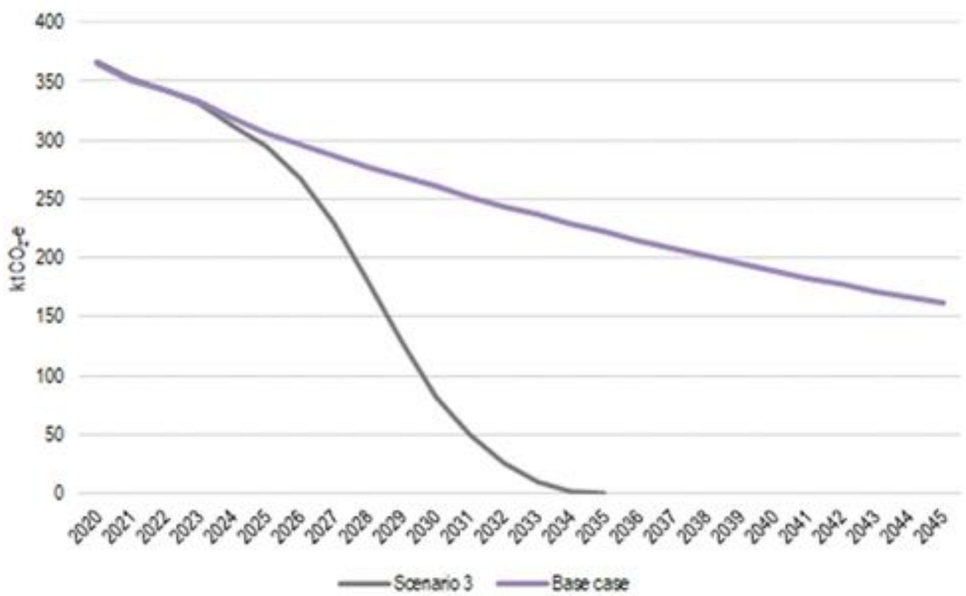
Source: ACIL Allen

8.3.2 Implications of demand forecasts

8.3.2.1 Emissions

Estimated emissions are currently around 350 kt of CO_2. This would reduce to zero tonnes by 2035. Emissions are presented below in Figure 133.

Figure 133 Natural gas projected emissions – Scenario 3 vs base case



Source: ACIL Allen

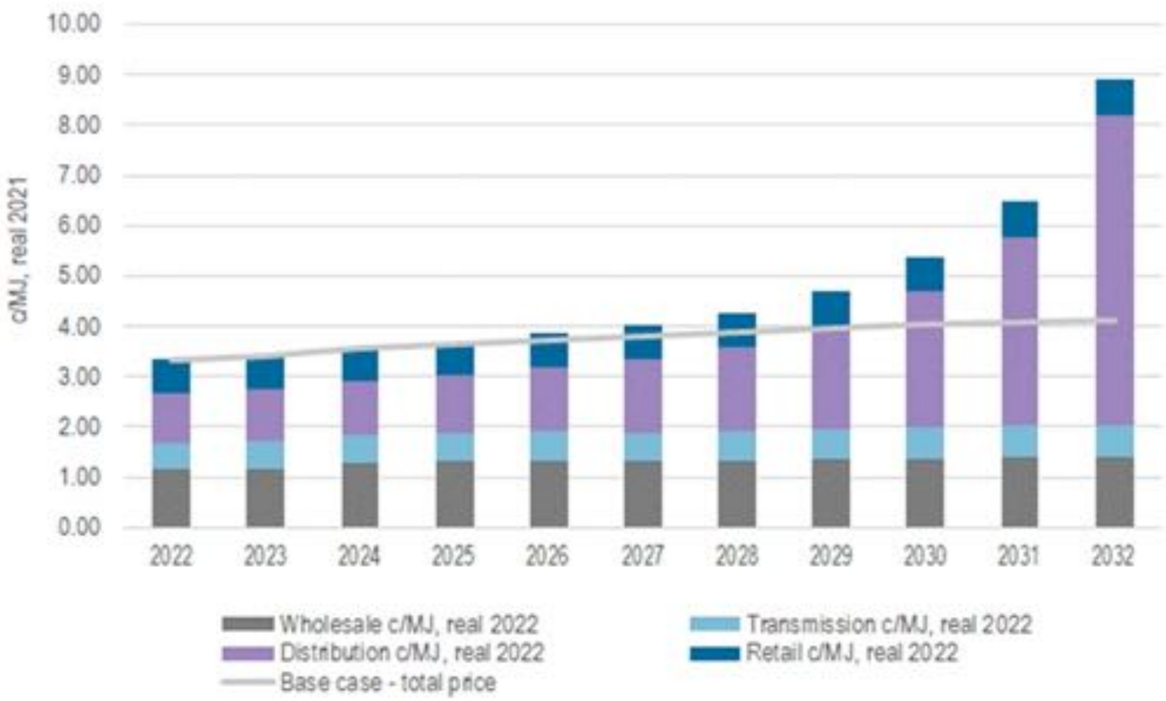
8.3.2.2 Gas pricing: retail prices

The total delivered retail price projected over the projection period is presented below in Figure 134. The price increases in real terms from levels around 3.3 cents/MJ to levels around 9 cents/MJ by 2032, and to levels beyond 15 cents/MJ by 2033. Beyond 2033, prices increase even more dramatically and this is obviously beyond a point that meaningfully matters.

Accordingly, we have demonstrated the increase to 2032. This highlights that, from the late 2020s, gas prices will be much higher than what consumers would bear, given current prices. For a household consuming around 35 GJ per annum, their residential gas bill would increase from around $1,155 per annum currently to $3,150 per annum in 2032, nearly a tripling of the current bill.

Analysis on tipping points is presented in the following chapter. However, it is clear that under this scenario it is likely that the gas network will become commercially unviable by the end of this decade, given the massive drop in connections (down to less than 20,000 by 2031) and the increase in prices that result.

Figure 134 ACT retail price for gas delivered to residential customers – Scenario 3 vs base case



Source: ACIL Allen

8.4 Electricity market modelling

We have adopted the same econometric approach to forecast peak demand and energy consumption in the ACT as was used for the base case. The modelling outcomes in relation to the key parameters varied from the base case are discussed in turn below.

8.4.1 Energy and peak demand forecast

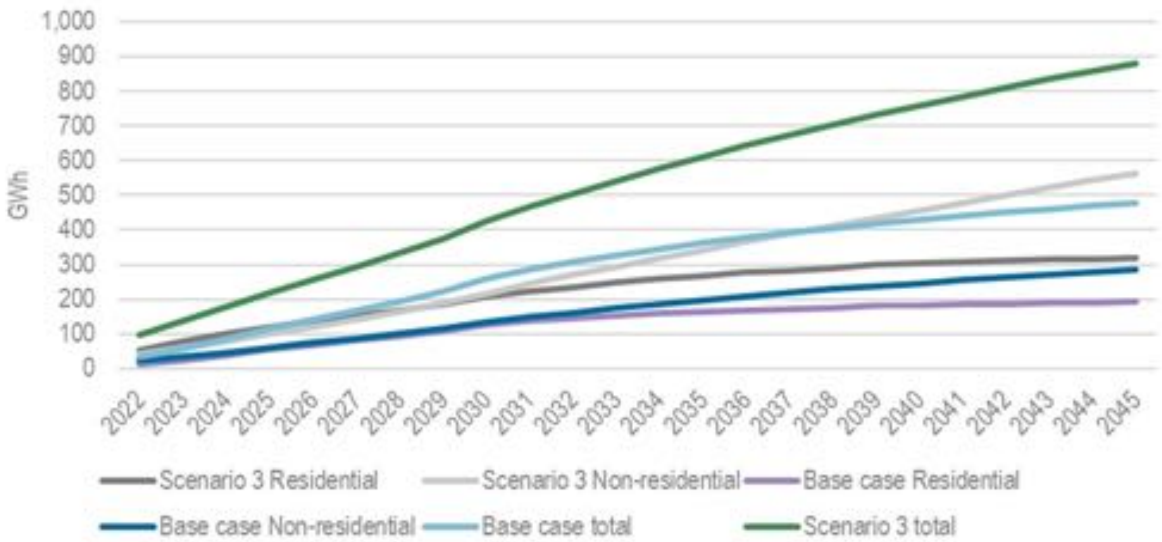
8.4.1.1 Energy efficiency

Scenario 3 assumes a high level of energy efficiency with savings of around 880 GWh by 2045 or around 80 per cent more energy savings than the base case (see Figure 135).

Scenario 3 is based on AEMO's ISP 'Step Change' and 'Hydrogen Superpower' scenarios and assumes NCC of 7 stars in 2022, 7.5 stars in 2027, 8 stars in 2030, and 8.5 from 2035. It also assumes a higher autonomous or market-led energy efficiency improvement than the other scenarios.

As discussed in the **Base case Report**, the scenarios include an explicit amount of energy efficiency savings which equal the amount of energy savings in GWh over and above the base case level.

Figure 135 ***Projected energy efficiency (GWh) - Scenario 3 vs base case***

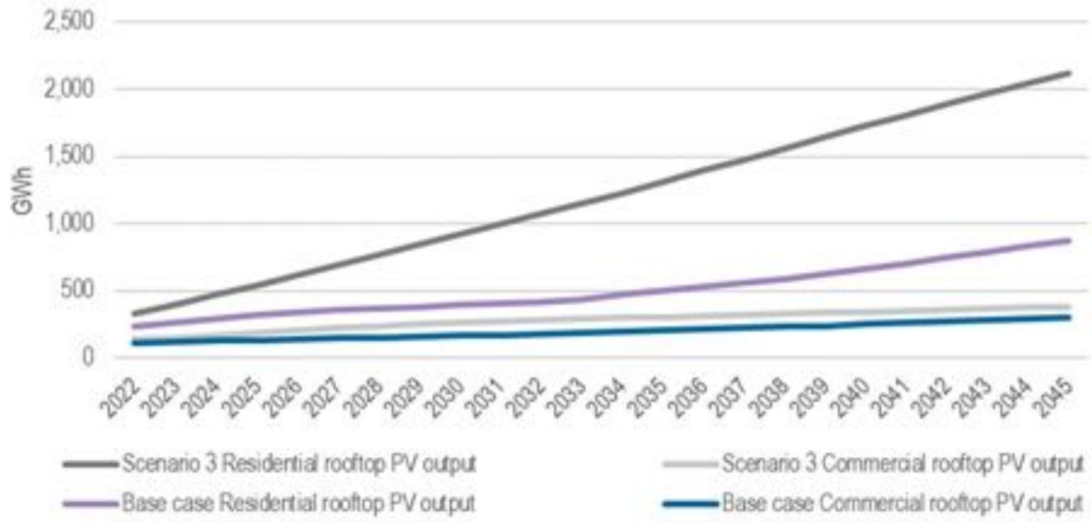


Source: AEMO ISP, ACIL Allen analysis

8.4.1.2 Behind-the-meter solar and battery energy storage systems

Scenario 3 assumes residential and commercial rooftop PV uptake reaches 95 per cent and 95 per cent, respectively, compared to 47 per cent and 90 per cent under the base case (see Figure 136).

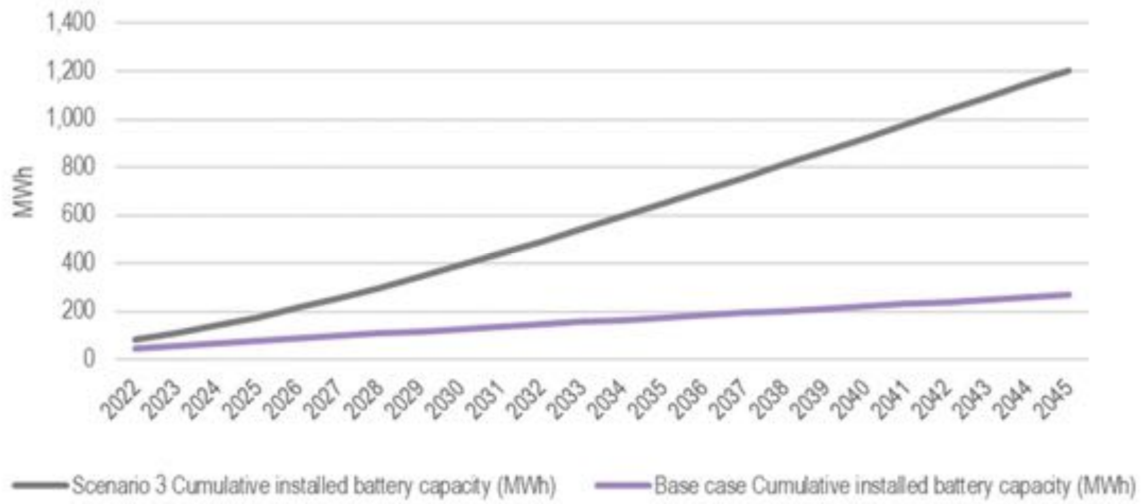
Figure 136 ***Projected rooftop PV output in the ACT, by consumer type (GWh) – Scenario 3 vs base case***



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

Scenario 3 assumes behind-the-meter BESS uptake reaches 85 per cent by 2045, compared to 25 per cent in the base case (see Figure 137).

Figure 137 ***Projected cumulative installed behind the meter BESS capacity (MWh) in the ACT – Scenario 3 vs base case***

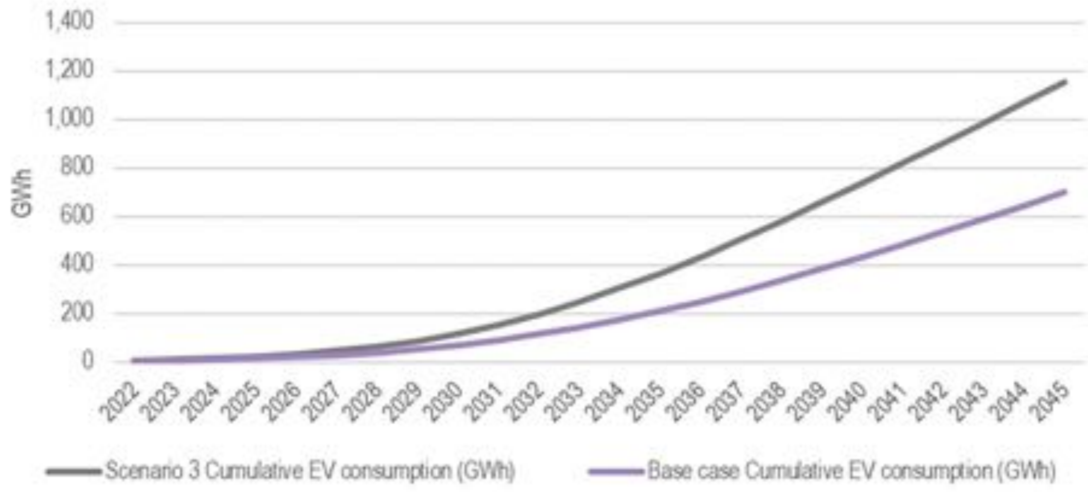


Source: ACIL Allen

8.4.1.3 Zero emission vehicles (ZEVs)

Scenario 3 assumes ZEV uptake reaches 68 per cent by 2045 (same as Scenario 1 and 2), compared to 41 per cent in the base case (see Figure 138). Of the ZEV fleet, 26 per cent by 2045 are assumed to be used as batteries to supply homes (V2H) or the grid (V2G).

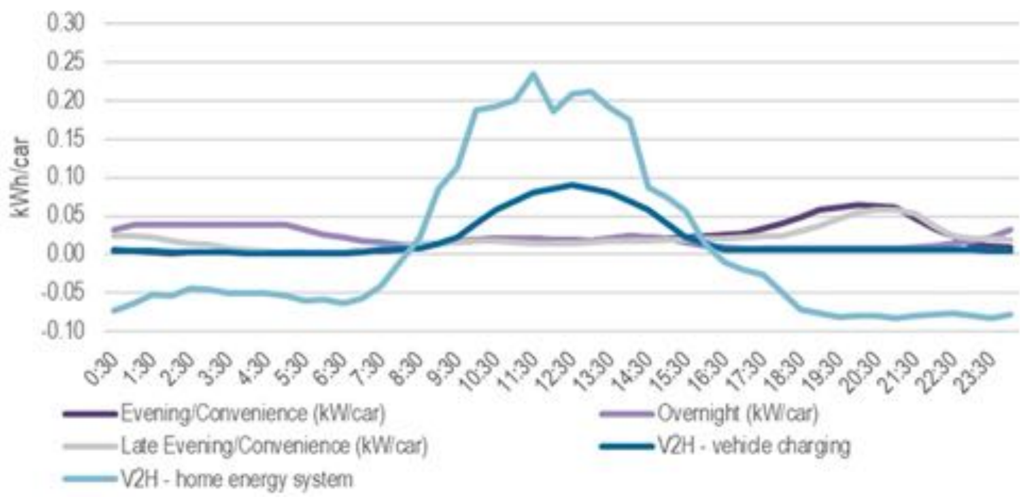
Figure 138 Projected annual energy requirements of passenger ZEV charging (GWh) – Scenario 3 vs base case



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

In addition to the charging profiles used in the base case (e.g. convenience, overnight, etc.), Scenario 3 incorporates a V2H vehicle charging profile and home energy system charging profile, based on AEMO's latest ISP assumptions which are identical to those assumed in Scenarios 1 and 2. The V2H has two profiles, "vehicle charging" for the purpose of charging the vehicle for transport purposes and "home energy system" that covers the storing and withdrawing of energy in the ZEV for the purposes of managing the household demand.

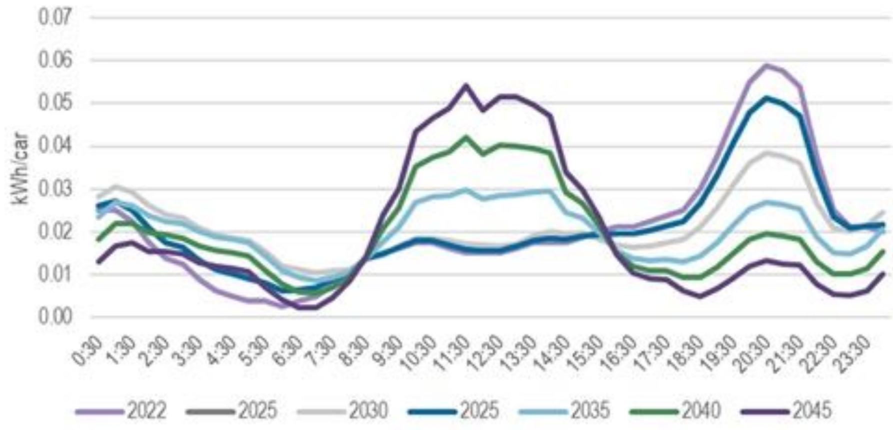
Figure 139 Average time of day ZEV charging profiles (kW/car) – Scenario 3



Source: ACIL Allen analysis of AEMO data

Similar to the base case, 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. As charging infrastructure is further developed and a percentage of ZEVs are used for V2H purposes, 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 (see Figure 140). The daytime peak is much more pronounced in Scenario 3 because of the large charging profile of the V2H home energy system. These assumptions are identical to Scenarios 1 and 2.

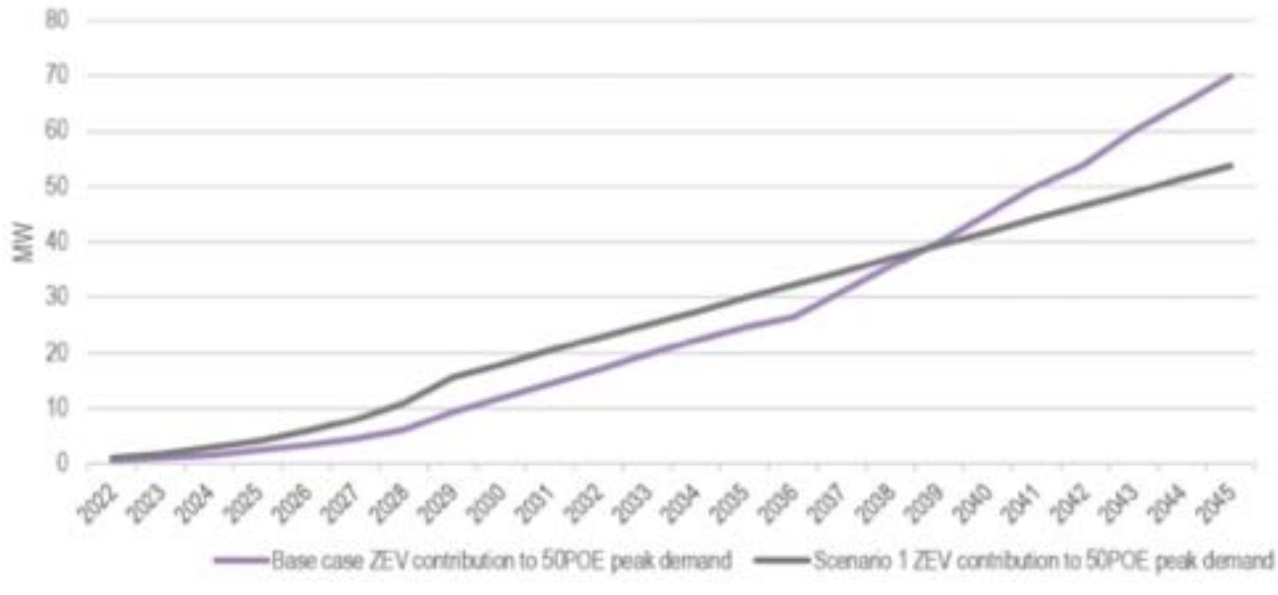
Figure 140 Weighted average combined time of day ZEV charging profile (kW/car) – Scenario 3



Source: ACIL Allen analysis of AEMO data

Figure 141 shows the projected contribution of ZEVs to 50POE peak demand (using a combination of AEMO's ISP EV charging profiles). The charging profiles change shape over time to reflect tariff reform, as well as the use of EVs as battery storage in the home (V2H).[32] The impact on peak demand is less in the later years, EV use as batteries in the home and on the grid (which reduces the impact on the peak).

Figure 141 Projected contribution of ZEVs to 50POE peak demand (MW) – Scenario 3 vs base case



Source: ACIL Allen

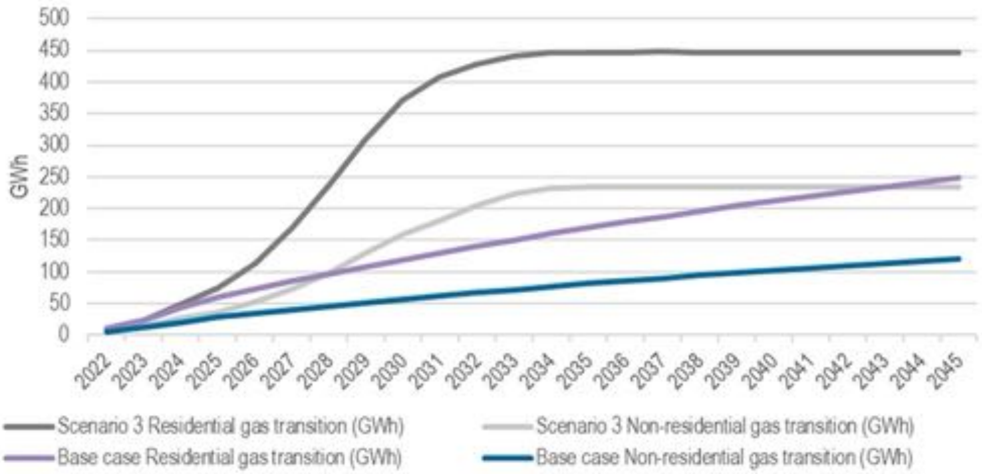
8.4.1.4 Electrification

Scenario 3 assumes demand for gas from the gas network reduces to zero in 2035, compared to a 60 per cent reduction by 2045 under the base case. The assumptions around electrification of specific commercial loads

[32] V2H is assumed to ramp up from <1% of EVs in 2030 to 13 per cent by 2045.

including the Canberra Hospital, Molonglo Commercial Centre, CIT Woden, Action bus fleet and Canberra Light Rail stage 2 remain unchanged from the base case. Figure 142 shows projected annual energy requirements from natural gas transition by customer type under Scenario 3 and the base case.

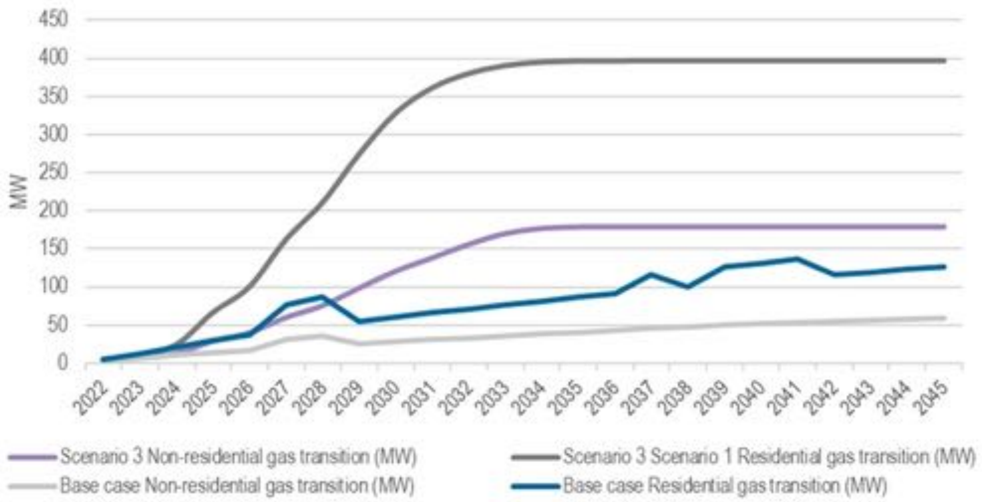
Figure 142 Projected energy requirements from natural gas transition (GWh) – Scenario 3 vs base case



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

Projected winter peak requirements attributed to natural gas transition under Scenario 3 and the base case are shown in Figure 143.

Figure 143 Projected contribution to the (winter) 50POE peak by natural gas transition (MW) – Scenario 3 vs base case



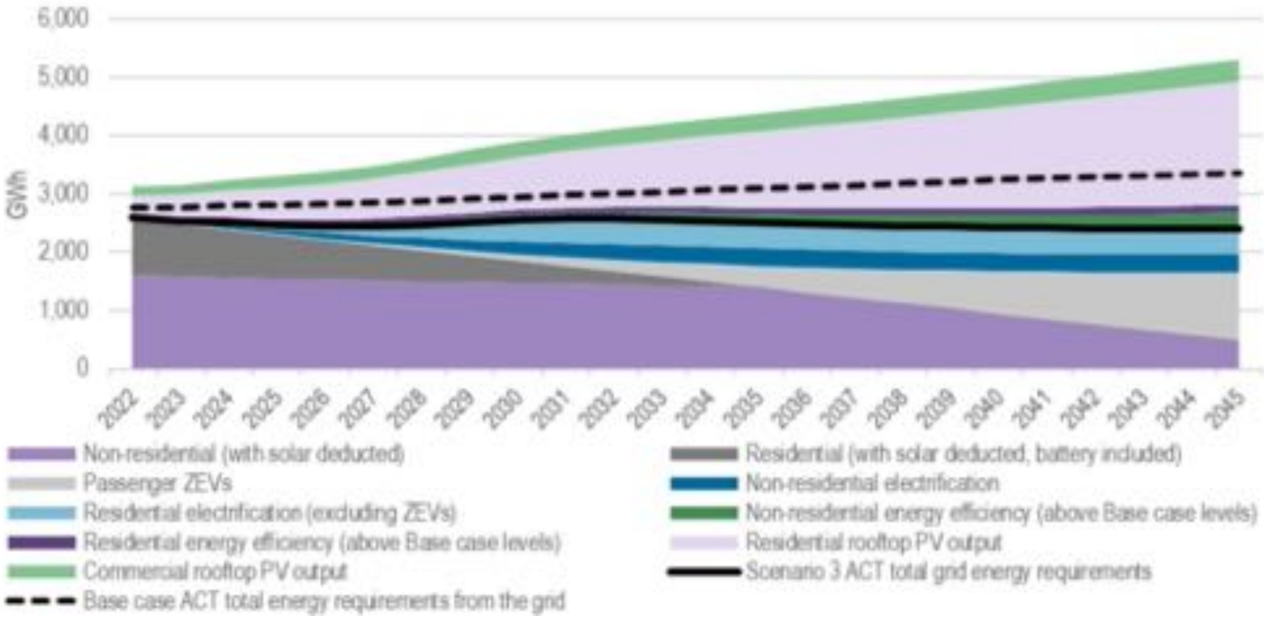
Note: Contribution of gas transition on the day and time of total ACT system 50POE peak demand. Non-residential gas conversion in this figure excludes Canberra Hospital and CNG bus fleet
Source: ACIL Allen analysis

8.4.1.5 Final energy and demand

Taking the assumed underlying demand together with the projected uptake of rooftop PV, BESS, ZEVs and other electrification, Figure 144 and Figure 145 below show the final assumed annual energy and peak demand projection. ACT total grid energy requirement is projected to decline from 2,772 GWh in 2022 to 2,406 GWh in 2045, which is a decline of around 13 per cent over the projection period, compared to an increase of 21 per cent in the base case.

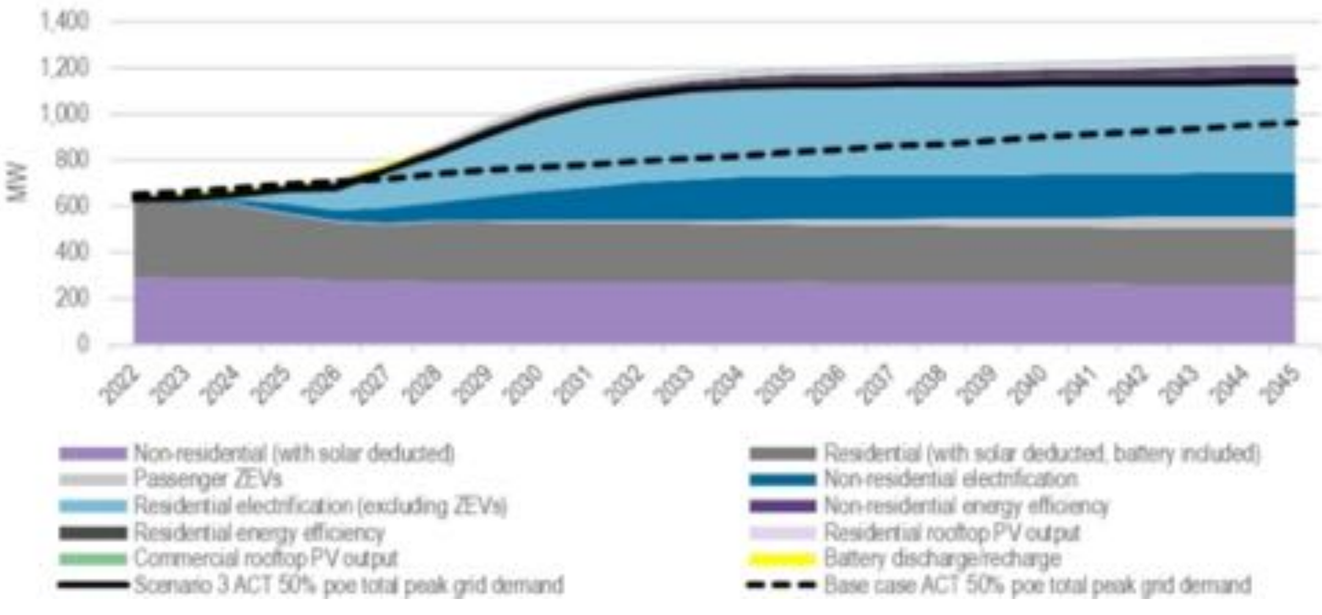
ACT 50POE peak grid demand is projected to grow from 654 MW in 2022 to 1,143 MW in 2045, which is an increase of around 75 per cent over the projection period, compared to 48 per cent in the base case.

Figure 144 ***Projected energy requirements (GWh) – by category – Scenario 3 vs base case***



Note: V2H is included in Passenger ZEVs. 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 145 ***Projected 50POE peak demand (MW) – by category – Scenario 3 vs base case***



Note: V2H is included in Passenger ZEVs. 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

Key factors encompassed in this outcome (a decline of around 13 per cent over the projection period) include:

- delivery of 51 per cent of total energy requirements through rooftop PV by 2045
- ZEVs comprise 68 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 behind-the-meter storage on the demand profile is small given the level of uptake projected
- taking out 40 per cent more gas consumption (from 60 per cent by 2045 in the base case to 100 per cent by 2045 in Scenario 3) only increases electricity energy requirements by 313 GWh by 2045 or 13 per cent of total grid energy requirements by 2045
- taking out 40 per cent more gas consumption has a larger impact on peak demand (winter), increasing it by 385 MW by 2045 or 34 per cent of total peak demand by 2045.

8.4.1.6 Average time of day demand

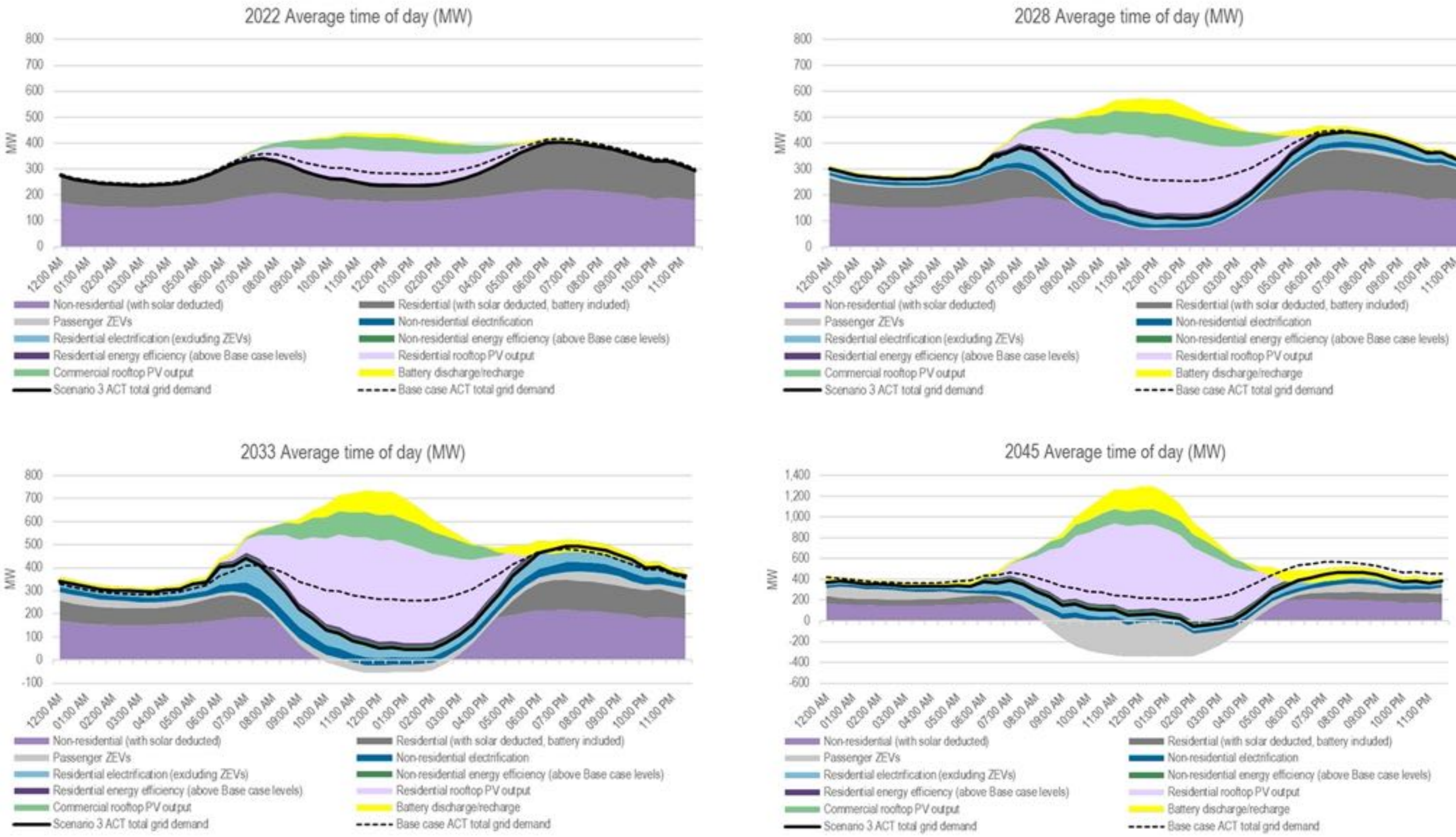
The projected higher uptake of rooftop PV installations, storage, and electrification in Scenario 3 will continue to change the shape of the time-of-day profile of demand in the ACT, resulting in lower average time of day demands during daylight hours compared to the base case. Figure 146 illustrates the impact of these technologies on the average time of day operational demand profile for 2022, 2028, 2033 and 2045.[33]

Similar to the base case, the graphs show the continuation of the 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 in the later years of the projection when uptake is high results in a noticeable reduction in evening demand (when batteries typically discharge) and an increase in daytime demands (when batteries typically recharge) compared to the base case.

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

Figure 146 Average time of day demand (MW) – for selected years – Scenario 3 vs base case



Note: V2H is included in Passenger ZEVs.

Source: ACIL Allen

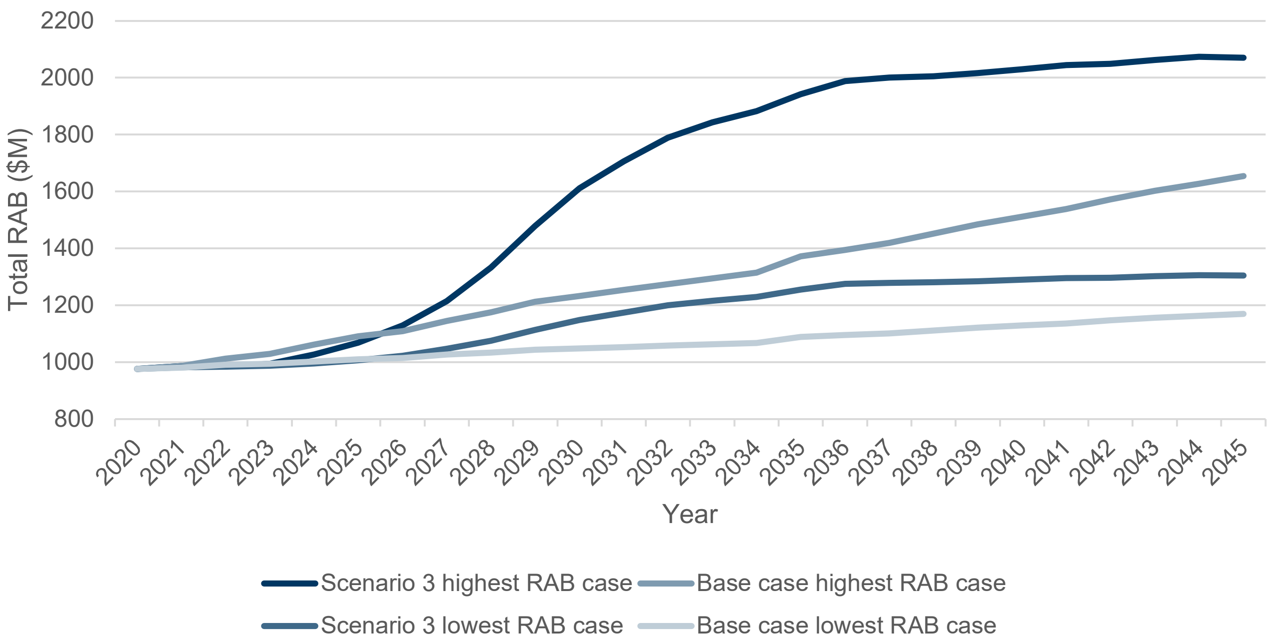
8.5 Electricity system network analysis

8.5.1 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. All modelling in all scenarios has been completed using the methodology provided in Section 4.3.

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 147 the range of the RAB between the most extreme cases is shown. All other modelling only considers the worst-case (highest) scenario RAB.

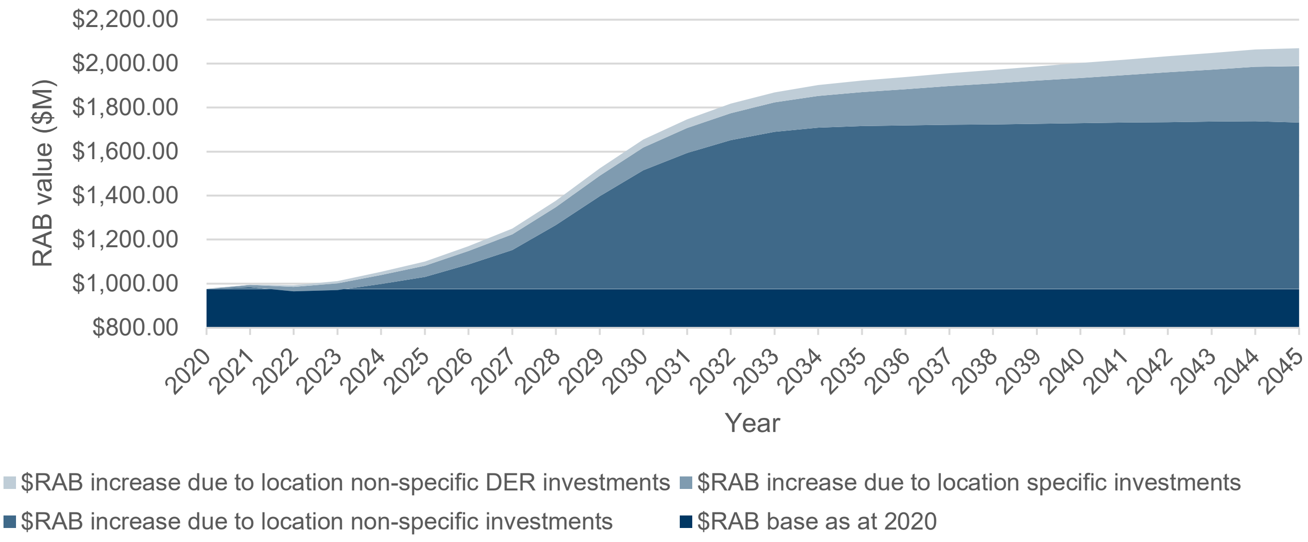
Figure 147 Comparison of highest and lowest possible RAB outcomes, Scenario 3



Source: GHD

The results of the modelling show that the total increase in the RAB over the period 2020-2045 is approximately $1,093 million as opposed to the increase in RAB over the same time in the base case of $678 million. Figure 148 shows the change in the RAB by type of investment in the Scenario 3 forecast (Refer Section 4.3 for detailed description of investment types).

Figure 148 Cumulative change in RAB in Scenario 3

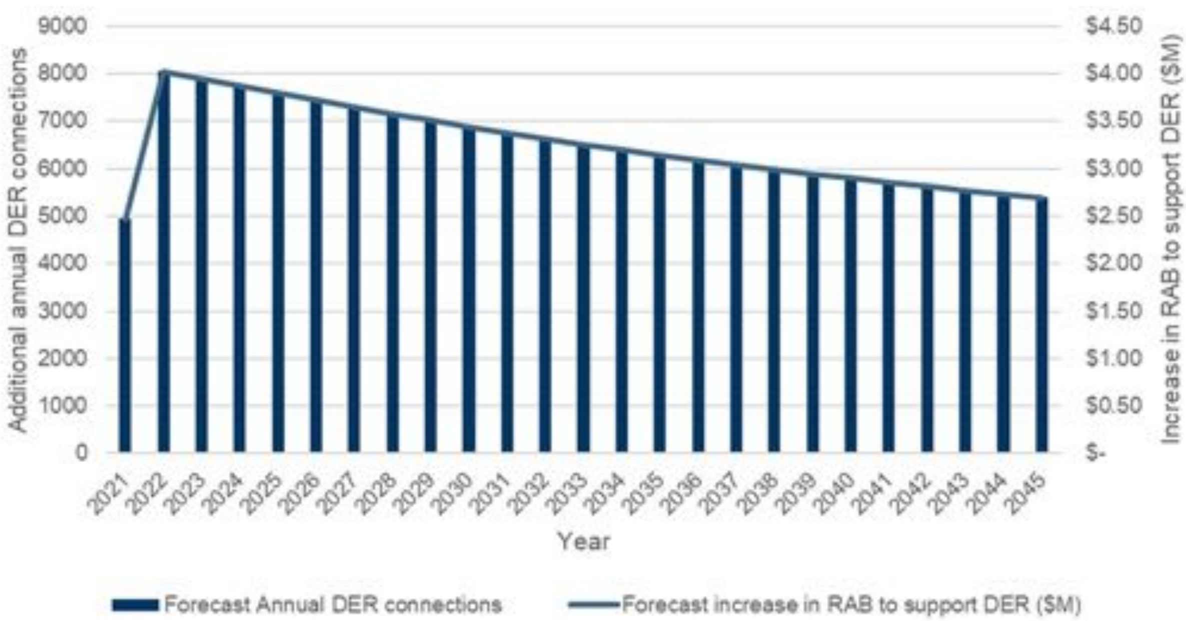


Source: GHD

Compared to the base case there is an increase in all forms of investment, which is driven by both the growth in demand and the increased up take of DER. The growth in demand has resulted in significant expenditure in both the non-specific investments (those to address power quality and low voltage limitations caused by increased customers and increasing demand from customers) and in the location specific projects (large material projects that will most be required to go through regulatory tests).

Compared to the base case scenario there is an increase in location specific projects from 20 projects totalling $154 million up to 31 projects totalling $251 million (these figures include projects already underway). The detailed list of projects identified as required in Scenario 3 is shown in Table 18. The increased uptake of DER and associated investment required to maintain quality of supply to customers is shown in Figure 149.

Figure 149 Additional DER and associated network investment forecast in Scenario 3



Source: GHD

Table 18 *Forecast specific investments required in Scenario 3*

KEY

+ = new or larger
↑ = moved forward
↓ = later date
x = no change

Year	Change from base case	Investment(s)	Estimated cost ($ million)
2022	x	Completion of the Molonglo battery station including first sub transmission line	13.7
2025	x	Install 3rd Transformer at Gold Creek zone substation	6.2
2027	x	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	x	Add third transformer to Molonglo zone substation and more feeders and further offload Woden zone substation to Molonglo	10.48
2030	↑ ↑	Construct 2 new distribution feeder out from East Lake Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	11.6
2031	↑ ↑	Build new sub transmission line between Canberra Terminal Station and Latham zone substation Construct 2 new distribution feeder out from Latham Zone substation	12.8
2032	↑ ↑ ↑ ↑	Construct 2 new distribution feeder out from City East Zone substation Construct 2 new distribution feeder out from Civic Zone substation Construct 2 new distribution feeder out from East Lake Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	23.2
2033	↑ ↑	Construct 3rd Transformer at Belconnen Zone substation Construct 2 new distribution feeder out from Latham substation	12.0
2034	↑ + +	Construct 2 new distribution feeder out from City East Zone substation Construct 2 new distribution feeder out from Civic Zone substation Construct 2 new distribution feeder out from Gold Creek Zone substation	17.4
2035	↓ ↑ + +	Establish new zone substation (ZS1) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Woden and Molonglo Construct 2 new distribution feeder out from Belconnen Zone substation Construct 2 new distribution feeder out from East Lake Zone substation Construct 2 new distribution feeder out from Latham Zone substation	48.62

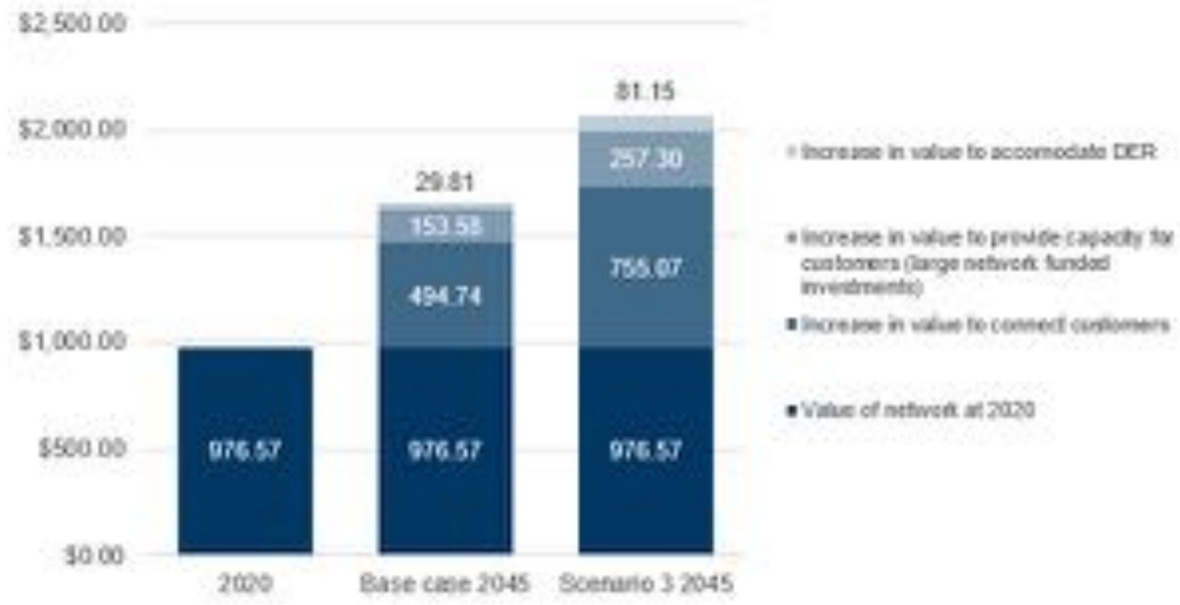
Year	Change from base case	Investment(s)	Estimated cost ($ million)
2036	+	Construct 3rd Transformer at East Lake Zone substation	40.32
	+	Establish new zone substation (ZS2) including new sub transmission lines, two transformers and multiple distribution feeders to offload and rebalance Civic, City East, East Lake and Telopea Park	
	+	Construct 1 new distribution feeder out from Gold Creek Zone substation	
2037	+	Construct 2 new distribution feeder out from Civic Zone substation to offload to ZS2	5.8
2039	+	Construct 2 new distribution feeder out from Belconnen Zone substation	5.8
2040	+	Construct 1 new distribution feeder out from Latham Zone substation	8.7
	+	Construct 2 new distribution feeder out from Telopea Park Zone substation to offload to ZS2	
2041	+	Construct 3 new distribution feeder to rearrange loads between Woden, Molonglo and ZS1	8.7
2043	+	Construct 2 new distribution feeder out from Belconnen Zone substation	5.8
2044	+	Construct 1 new distribution feeder out from Latham Zone substation	2.9

Source: GHD

8.5.2 Impact on network investment

The Scenario 3 forecast will require investment of an additional $1,093 million in the network to 2045 (increasing the RAB valuation from $976.57M in 2020 to $2,070M in 2045). The relative magnitude of the growth in the various segments of the network are shown in Figure 150 below compared to the same period in the base case.

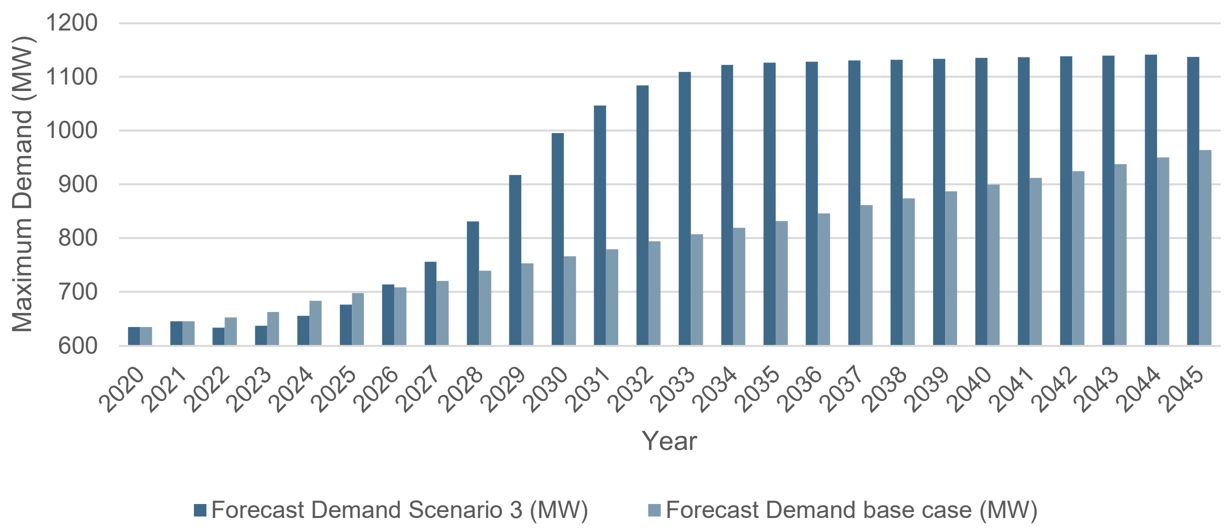
Figure 150 Change in value of the distribution asset base 2020-2045, $ million



Source: GHD

The main changes in Scenario 3 compared to the base case relate to a significantly higher growth in demand from 2026 to 2034 when the Scenario 3 demand growth then flattens out but is still maintained at a higher level than the base case as shown in Figure 151.

Figure 151 Change in network demand between Scenario 2 and base case



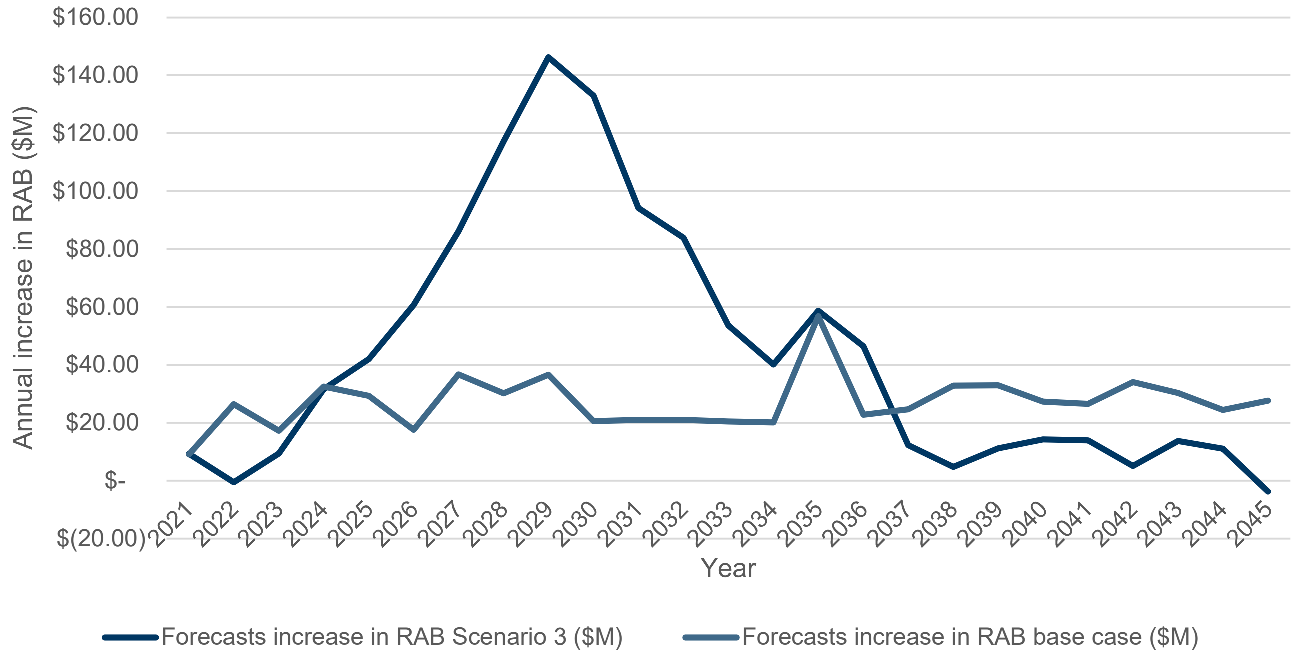
Source: GHD

The changed growth in demand impacts on the projects required by requiring significant investment in the RAB to occur between 2025 and 2035, as shown in Figure 152. As the demand then flattens out the level of investment required is significantly reduced as most investment is to meet capacity constraints.

With the demand no longer growing, there are few new capacity constraints identified and less investments. Most of the investment in this scenario is in the areas where high populations already exist (Civic, City East, East Lakes, Latham and Telopea Park) and areas where population growth is forecast (Belconnen, Gold Creek, Molonglo and Woden). The areas where the high population already exists have large investment due to the rapid transition from gas heating to electric. With the rate of the transition being up to six times higher than in the other scenarios, many investments are identified very early to meet the increased demand.

The areas with high population growth have investments more driven by the increase in population as the transition to gas effects a smaller pool of customers in these areas. The investments in these areas have timing that is fairly consistent with the other scenarios and base case. Uptake of DER and batteries is not as much of an influencer in this scenario due to the significant growth in demand due to the transition away from gas. While all DER and batteries will assist in reducing demand, it is not a significant driver in deferring projects in this scenario.

Figure 152 Change in annual increase in RAB between Scenario 3 and the base case



Source: GHD

8.5.3 Constraints

The only real constraint identified in each of the scenarios and base case modelled is how much capital can be made available to maintain existing levels of safety, security and reliability for the forecast change in demand in the network.

That being said, in Scenario 3 an additional zone substation was identified as being required to help offload the Civic, City East, East Lake and Telopea Park areas. All of these locations are reasonably well-developed parts of the ACT which may make it difficult to identify a suitable location both in terms of land for a new substation but also in terms of being able to establish new lines in locations where lines already exist. This type of constraint could result in significant increases in expenditure beyond that which has been forecast for the project if the location of the substation ends up in a difficult location to connect.

Further to this, the works program identified in this scenario is significant in the 2030-2040 period and drops off again after 2040. Resourcing this type of work program could be difficult both in terms of materials and labour, and in the event that labour needs to be acquired from other regions in Australia, the price of the work could escalate further.

During that the 2030-2040 period the high volume of work may also make delivery of the work difficult from an operational point of view as there will be requirements to transfer loads within the network while works are being undertaken. This will potentially also result in additional customer disruptions (mostly switching rather than outages) during the period of work.

8.6 Electricity retail bill impacts

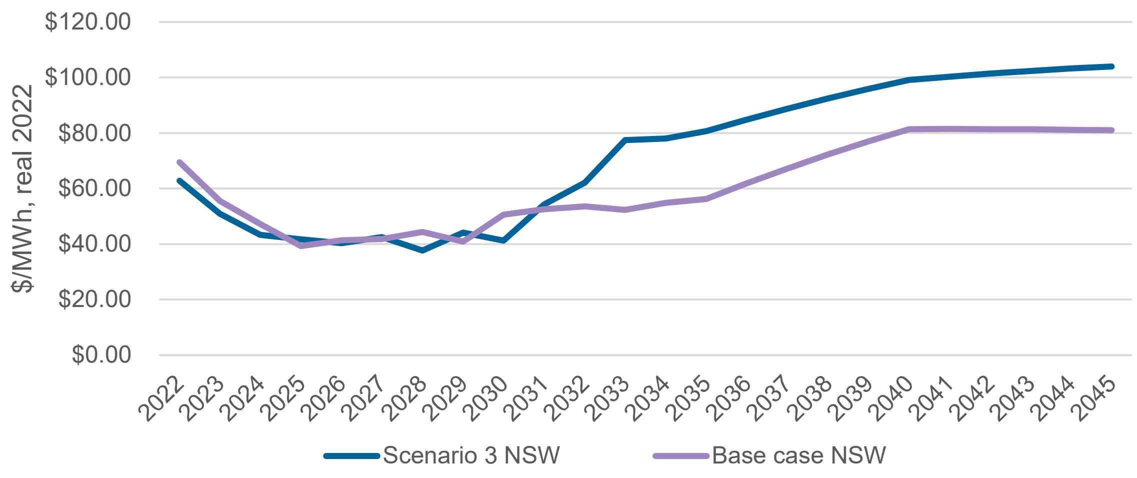
8.6.1 Wholesale component

Similar to the base case, PowerMark projected wholesale prices in the NSW NEM region have been used to estimate the Scenario 3 wholesale cost component of the retail bill.

Scenario 3 is based on the base case, but with an adjustment to account for higher uptake of distributed generation (rooftop solar PV), behind-the-meter battery storage and large-scale grid storage systems.

The resulting projected time-weighted spot prices for the NSW region are shown in Figure 153, compared to the base case. In the short- to medium-term, projected prices are similar to the base case due to the increase in distributed generation mostly offsetting higher demand from electrification. In the medium- to long-term, projected prices are higher than the base case due to higher demand from electrification and higher costs of generation, similar to Scenarios 1 and 2.

Figure 153 ***Projected time weighted prices for NSW region ($/MWh, real 2022) – Scenario 3 vs base case***



Source: ACIL Allen

8.6.2 Network component

Similar to the base case, ACIL Allen has projected annual regulated revenues based on the building blocks method 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.

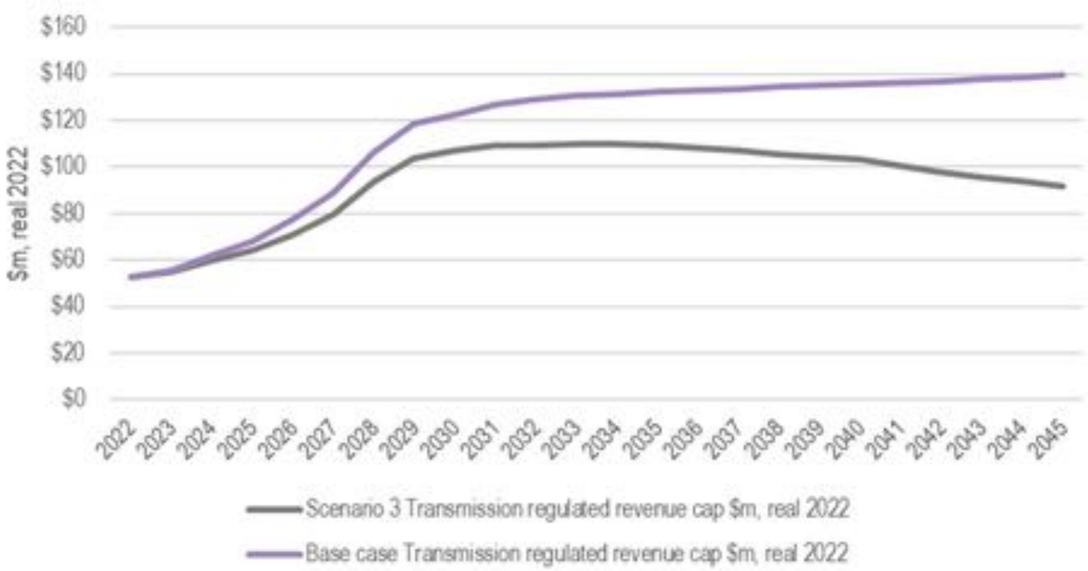
8.6.2.1 Transmission

Figure 154 shows projected annual revenues recovered by Evoenergy through TUOS tariffs. Projected TUOS revenues assume significant capital expenditure by TransGrid for network augmentation under Scenario 3 associated with the ISP actionable projects and investment in new generation from electrification under Scenario 3.

Projected revenues for the ACT TUOS component are allocated using the proportion of ACT electricity consumption relative to NSW electricity consumption.

Despite increased projected network augmentation of the TransGrid network under Scenario 3 (compared to the base case), projected revenues apportioned to ACT customers are lower than the base case, given that the increase in electricity consumption across NSW (due to higher electrification across the NEM) is proportionally higher than the increase in consumption in the ACT. That is, the higher transmission spending required in Scenario 3 is smeared across a larger consumption base in NSW.

Figure 154 Projected annual revenues for transmission ($ million, real 2022) – Scenario 3 vs base case

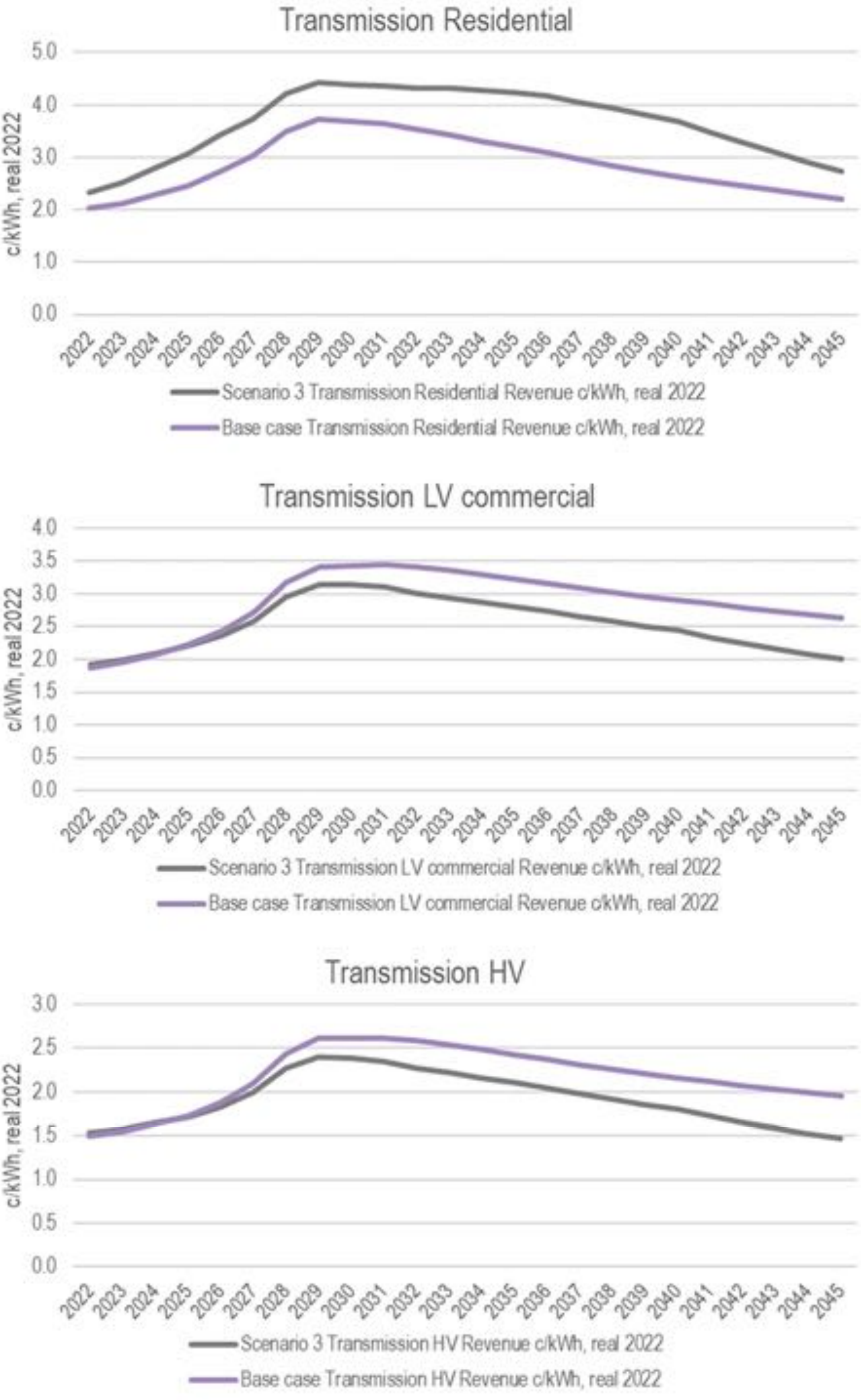


Source: AER, TransGrid, Evoenergy, ACIL Allen

Projected TUOS tariffs by customer type are shown in Figure 155. Similar to the base case, projected TUOS tariffs in Scenario 3 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.

TUOS tariffs are higher than the base case for residential customers due to significant reduction in the residential consumption base in Scenario 3. The rate of decline in residential TUOS tariffs is projected to increase from around 2035 due to the impact of higher residential consumption from passenger ZEVs in Scenario 3, which is the same as for Scenario 1 and 2.

Figure 155 Projected TUOS tariff, by customer type (c/kWh, real 2022) – Scenario 3 vs base case

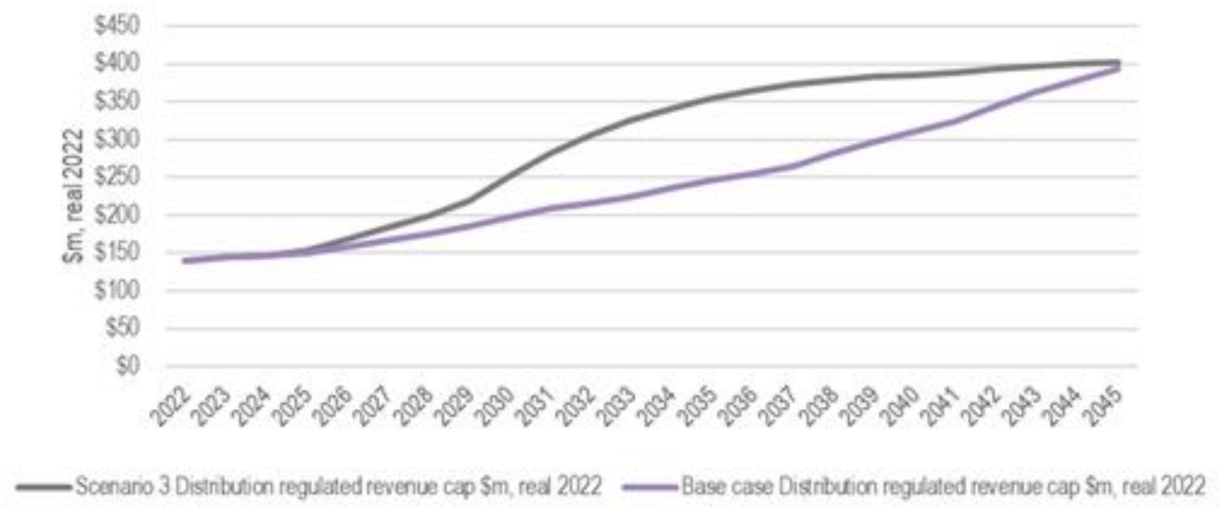


Source: AER, Evoenergy, ACIL Allen

8.6.2.2 Distribution

Similar to the base case, 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 Section 8.5) into this analysis. Figure 156 shows projected annual revenues recovered by Evoenergy through DUOS tariffs. From around 2025, Scenario 3 projected annual revenues are between two per cent and 45 per cent per annum higher than the base case, reflecting greater network spend in Scenario 3.

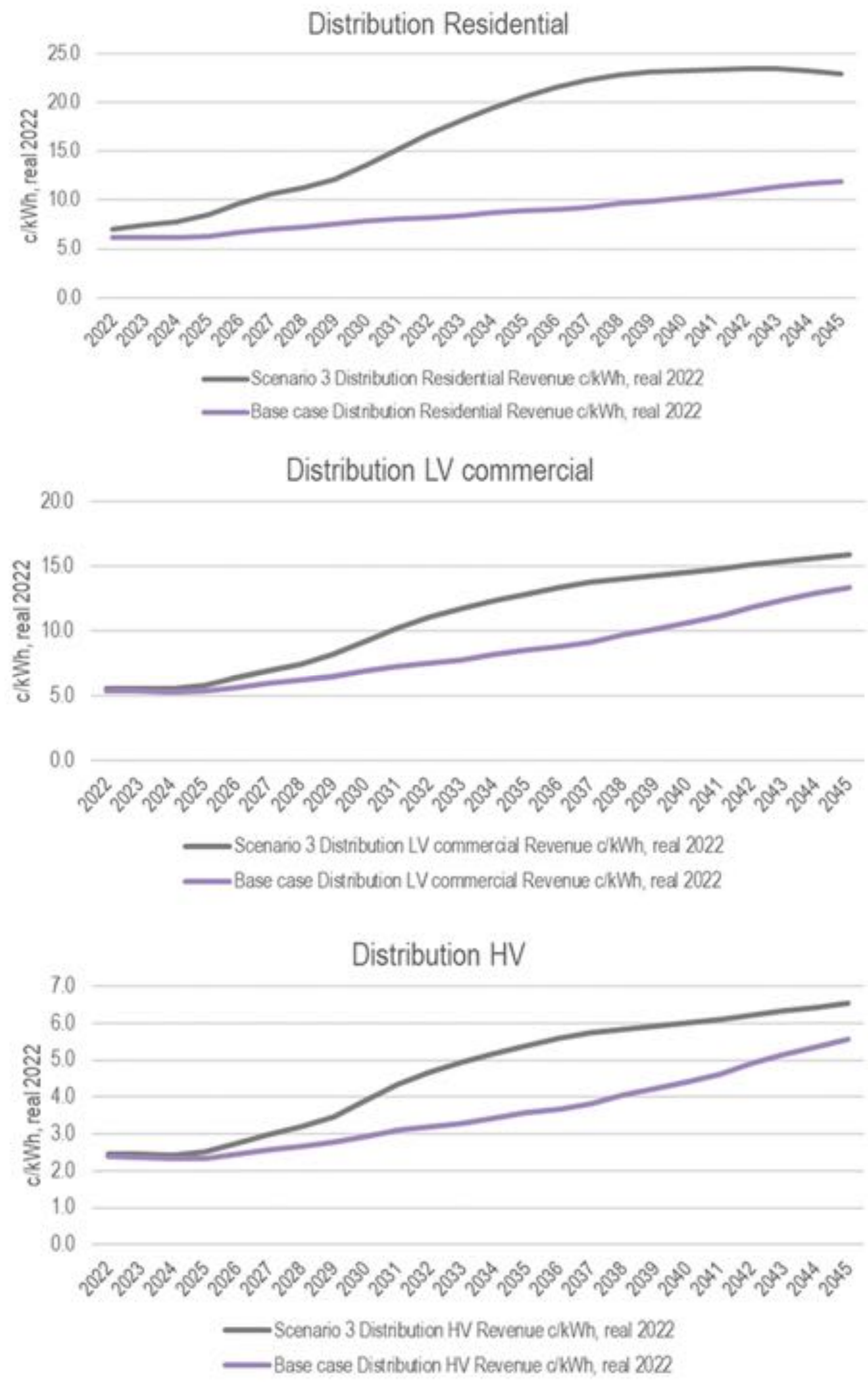
Figure 156 Projected annual revenues for distribution ($ million, real 2022) – Scenario 3 vs base case



Source: AER, Evoenergy, ACIL Allen

Projected DUOS tariffs by customer type are shown in Figure 157 below. Projected DUOS tariffs for residential, LV commercial and HV customers are substantially higher than the base case, particularly from around 2030, due higher projected regulated revenues smeared across a smaller consumption base.

Figure 157 Projected DUOS tariff, by customer type (c/kWh, real 2022) – Scenario 3 vs base case



Source: AER, Evoenergy, ACIL Allen

8.6.2.3 Jurisdictional schemes

Similar to the base case, 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 large FiT payments are shown in the chart below and compared to the base case. We have assumed no change to the auction wind farms - they have the same installed capacity, timing, and contract price.

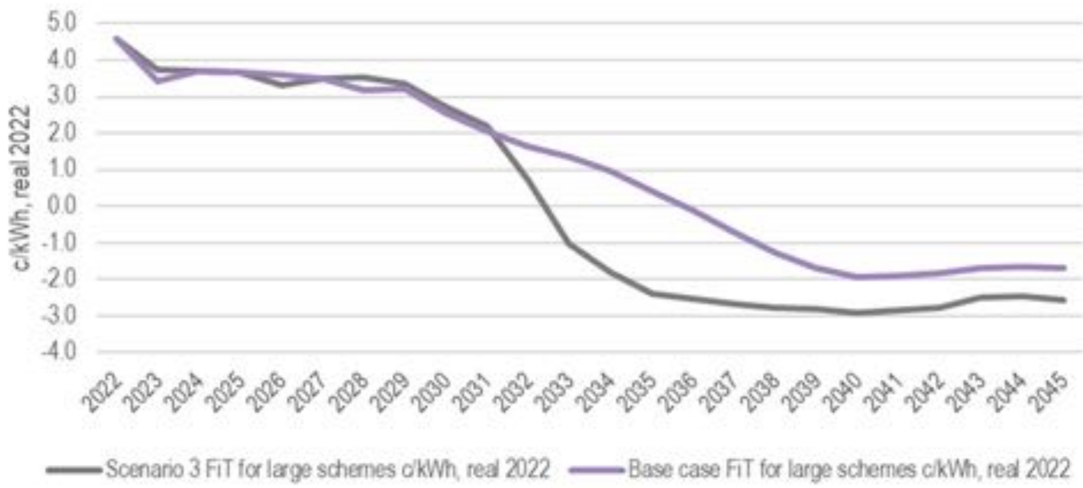
Scenario 3 payments are similar to the base case to around 2030 which is consistent with similar wholesale prices between this scenario and the base case. Post 2030, lower payments are largely the result of higher projected wholesale electricity spot prices in Scenario 3.

Similar to the base case and other scenarios, over the period to 2030, 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[34].

After 2030, projected wholesale electricity prices rise with the closure of several major coal fired power stations and growth in demand from projected electrification including ZEV uptake, which results in a decline in projected large FiT payments.

As indicated in Figure 158, large FiT payments are projected to continue to decline and by around 2033 are projected to become negative (resulting in net revenue to the ACT Government/Evoenergy/customer) as projected wholesale spot prices rise, given further coal power plant closures and demand growth.

Figure 158 Projected large feed in tariff payments (c/kWh, real 2022) – Scenario 3 vs base case



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

Similar to the base case, Scenario 3 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

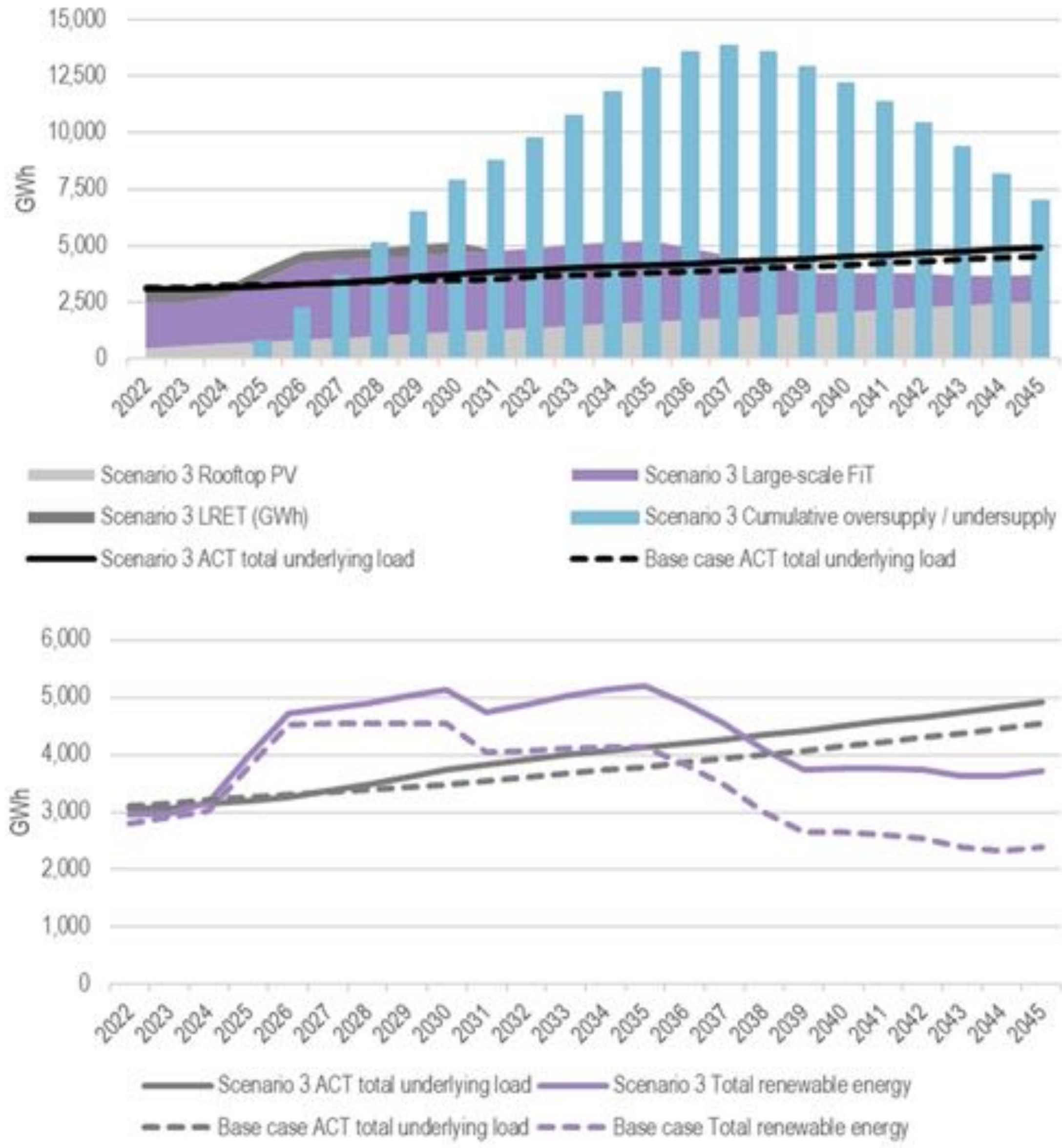
[34] Assumed new supply from large-scale grid renewable supply proposed by state-based schemes such as the NSW Roadmap and also from behind-the-meter generation.

renewable mark from 2038, declining to around 76 per cent of underlying demand by 2045 as shown in the first figure below (see Figure 159).

Based on the figure, the government could need to factor in a further auction of renewable electricity around 2035. However, under the current policy renewable electricity in excess of 100 per cent target is 'banked' with credits carrying over to future years. These 'banked' credits are carried forward built into the cumulative oversupply/undersupply blue bars at the first figure below. These credits offset the need for additional purchases beyond the 2045 period.

The second figure below shows that Scenario 3 has more renewable supply in GWh terms than the base case and very similar underlying demand as the base case. As discussed above, we have assumed no change to the auction wind farms. The difference lies in how the wind farms are dispatched in Scenario 3. Similar to Scenarios 1 and 2, due to higher demands across the NEM from electrification, the auction wind farms experience lower levels of curtailment (or higher dispatch) than in the base case and therefore more supply in GWh towards the target.

Figure 159 Projected contribution by category to 100% renewable energy (GWh) – Scenario 3 vs base case

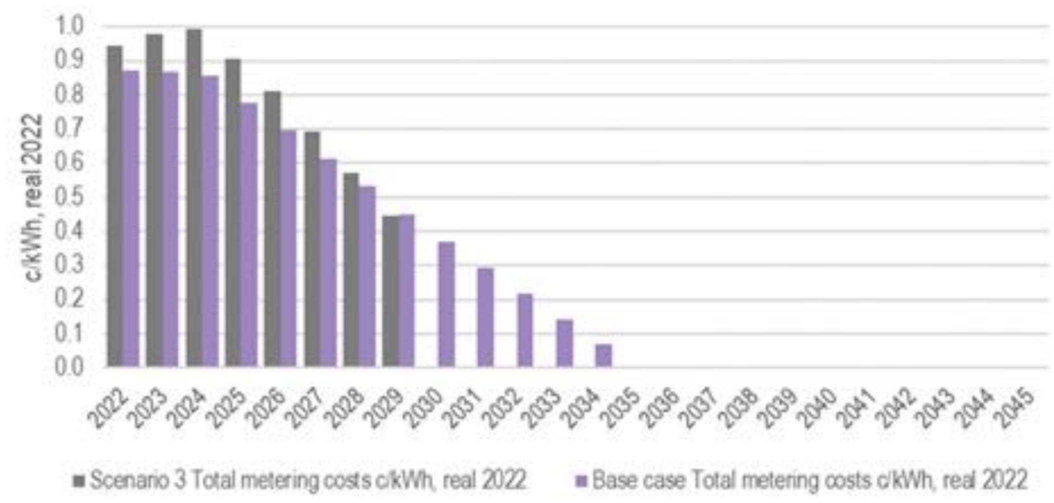


Note: Excludes GreenPower. We have assumed GreenPower covers projected under supply in 2022-2024.
Source: ACIL Allen analysis

8.6.2.4 Metering

Regulated metering charges cover the costs associated with Evoenergy's provision of regulated Type 5 and Type 6 metering services.[35] The projections illustrated at Figure 160 assume that Type 5 and Type 6 meters are phased out completely before 2030 under Scenario 3, which is earlier than the base case. Annual regulated metering costs in c/kWh are generally slightly higher than the base case as a result of the lower consumption base.

Figure 160 Projected metering costs (c/kWh, real 2022) – Scenario 3 vs base case

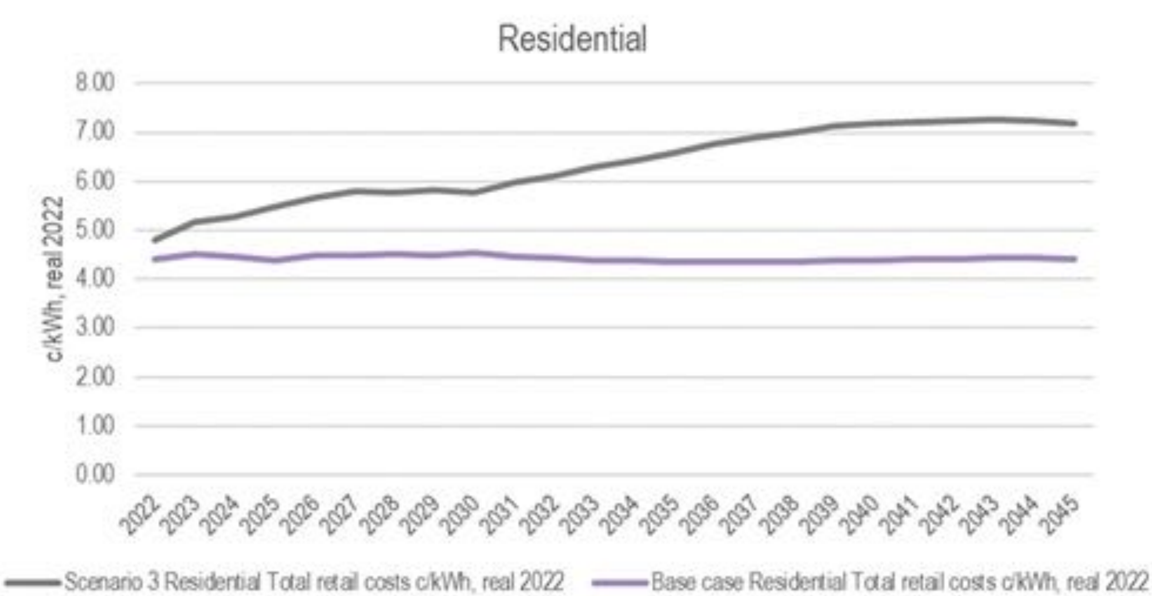


Source: ACIL Allen, AER, Evoenergy

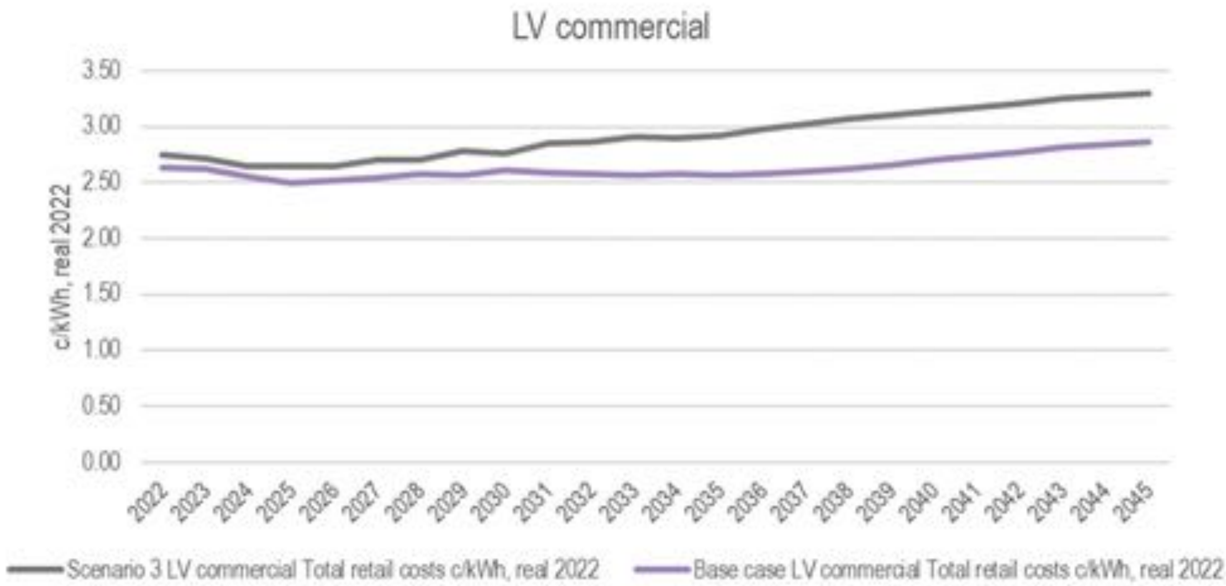
8.6.3 Retail component

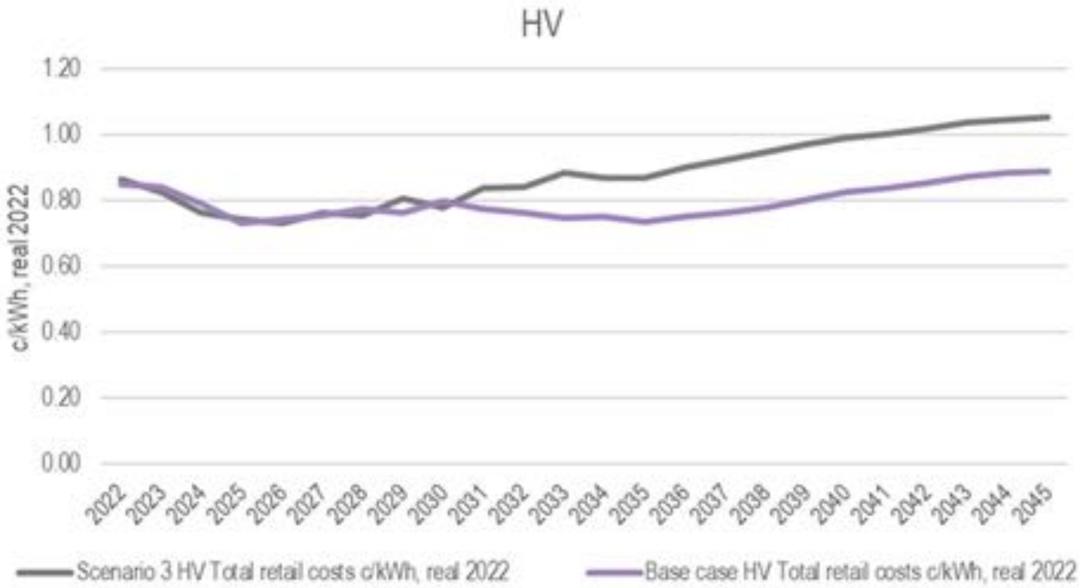
Scenario 3 projected total retail costs are generally higher than the base case, as illustrated at Figure 161, due to higher assumed smart meter costs (residential and LV customers only), higher energy efficiency scheme costs (residential and LV customers only), and higher retailer margin (all customers). The lower consumption base also drives higher retail component in c/kWh for residential customers.

Figure 161 Projected cost of retail component, by customer type (c/kWh, real 2022) – Scenario 3 vs base case



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





Source: ICRC, ACIL Allen

8.6.4 Total retail prices

Bringing together the wholesale, network and retail components discussed in this Chapter, the projected retail prices are shown in Figure 162.

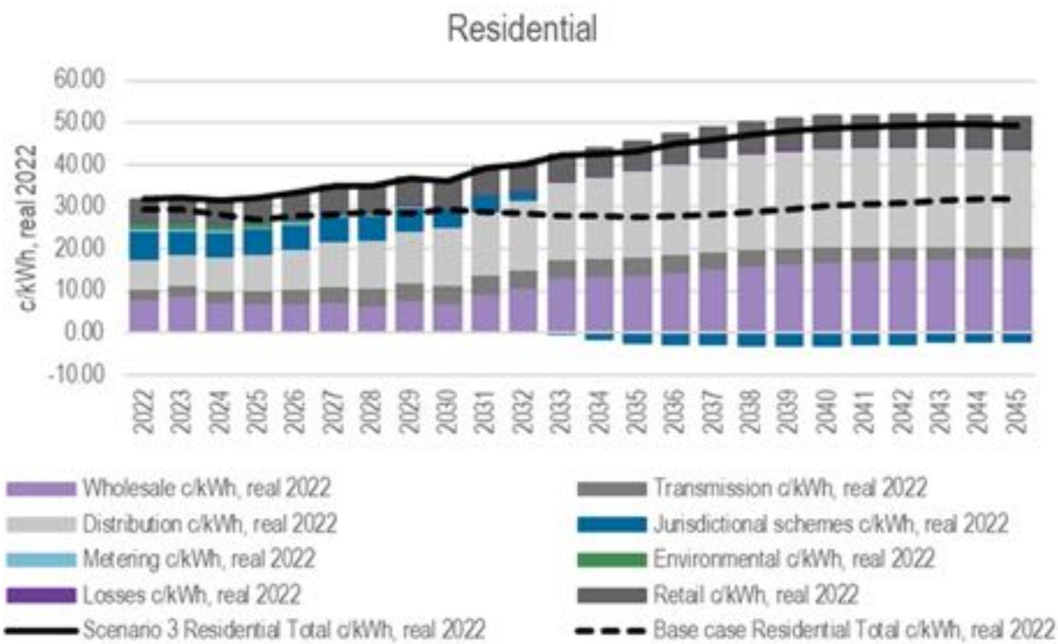
In Scenario 3, real retail prices for residential, LV commercial and HV customers are projected to increase by 55 per cent, 36 per cent and 22 per cent respectively over the period from 2022 to 2045, compared to nine per cent, 19 per cent and five per cent in the base case. Key drivers of the increase are the wholesale and distribution costs which are partially offset by a decline in the cost of the large FiT payments over the period.

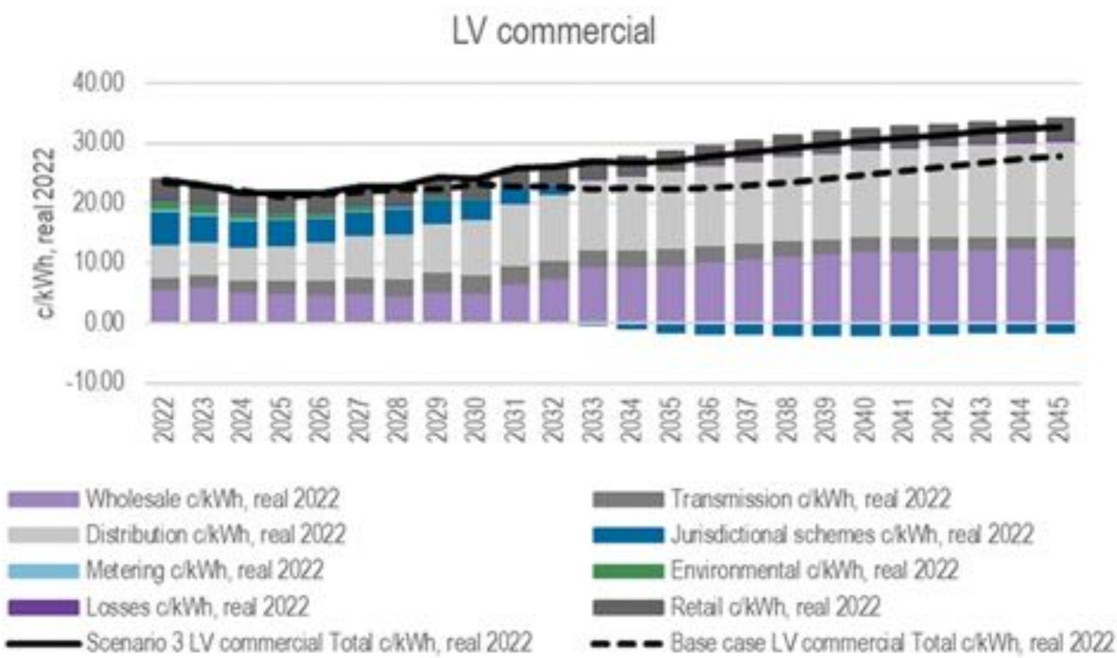
The projections by component are discussed further below.

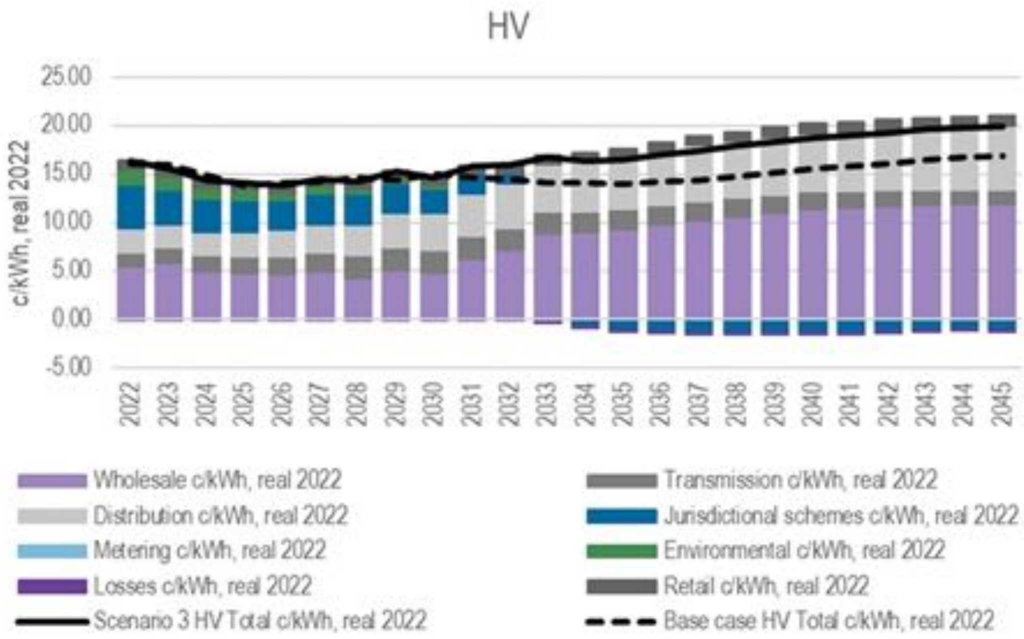
- Wholesale component – is projected to remain at current low levels until around 2029 given the significant amount of new large-scale grid supply assumed to enter the market under state-based schemes and also due to an increase in supply from behind-the-meter solar generation. From 2030, the projected wholesale component rises, reflecting the closure of several major coal fired power stations and growth in demand from projected electrification, including ZEV uptake. From around 2040, projected wholesale prices are capped at the long-run cost of new entrant supply.

- Network component (transmission) – is projected to rise over the period to 2030 because of projected capital expenditure to support major transmission network augmentations. After 2030, accelerated consumption growth in the broader NSW region is projected to surpass revenue growth, resulting in a declining transmission component.
- Network component (distribution) – is projected to grow significantly over the period to 2045, with a projected faster rate of growth over the period to 2035 and a slower growth between 2035 and 2045, in line with the projected capital expenditure to support major distribution network augmentations.
- 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 around 2034, the large FiT is expected to return net revenues to customers.
- Network component (metering) – is projected to decline over the period to 2030 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 customers, this component is projected increase over the period to 2045 consistent with higher retailing costs and declining consumption over time. For high voltage customers, 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 162 Projected retail prices in the ACT, by component, by customer type (c/kWh, real 2022) – Scenario 3 vs base case







Source: ACIL Allen

8.6.5 Retail bill

We have estimated projected retail bills for different customers (see Figure 163) by multiplying the projected retail price (see Section 8.6.4 above) by the projected average consumption per customer.[36]

Projected average consumption per customer declines over the period to around 2045 because of the projected increase in penetration of rooftop solar PV and high levels of energy efficiency improvements, which are only partially offset by increases in demand from electrification.

Over the period to 2030, projected retail bills for residential, LV commercial and HV customers are projected to decline in real terms by six per cent, increase by one per cent and decline by 10 per cent, respectively. This is the result of the projected decline in large FiT payments and costs associated with the Commonwealth Government's environmental schemes offsetting projected increase in transmission and distribution network costs.

Over the period from 2030 to 2045, projected retail bills for residential, LV commercial and HV customers increase by 10 per cent, 20 per cent and 30 per cent, respectively. These increases reflect the projected increase in wholesale and distribution network costs, which are only partially offset by the projected decline in large FiT payments and transmission network costs.

In Scenario 3, the retail bills for residential, LV commercial and HV customers (in real terms) are projected to increase by three per cent, 21 per cent and 17 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 19 per cent, 19 per cent and 12 per cent, respectively).

At the start of the projection period, wholesale costs comprise around 30 per cent of the residential bill, distribution costs 20 per cent, and large FiT costs 20 per cent. By 2045, wholesale costs grow to 40 per cent of the residential bill, distribution costs grow to 40 per cent and large FiT costs decline to around 3 per cent. A similar trend is projected for the low and high voltage commercial bills.

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[36] 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.

Figure 163 Projected retail bill (left chart), by component, by customer type ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS) – Scenario 3 vs base case; Projected customer numbers (right chart)

Source: ACIL Allen

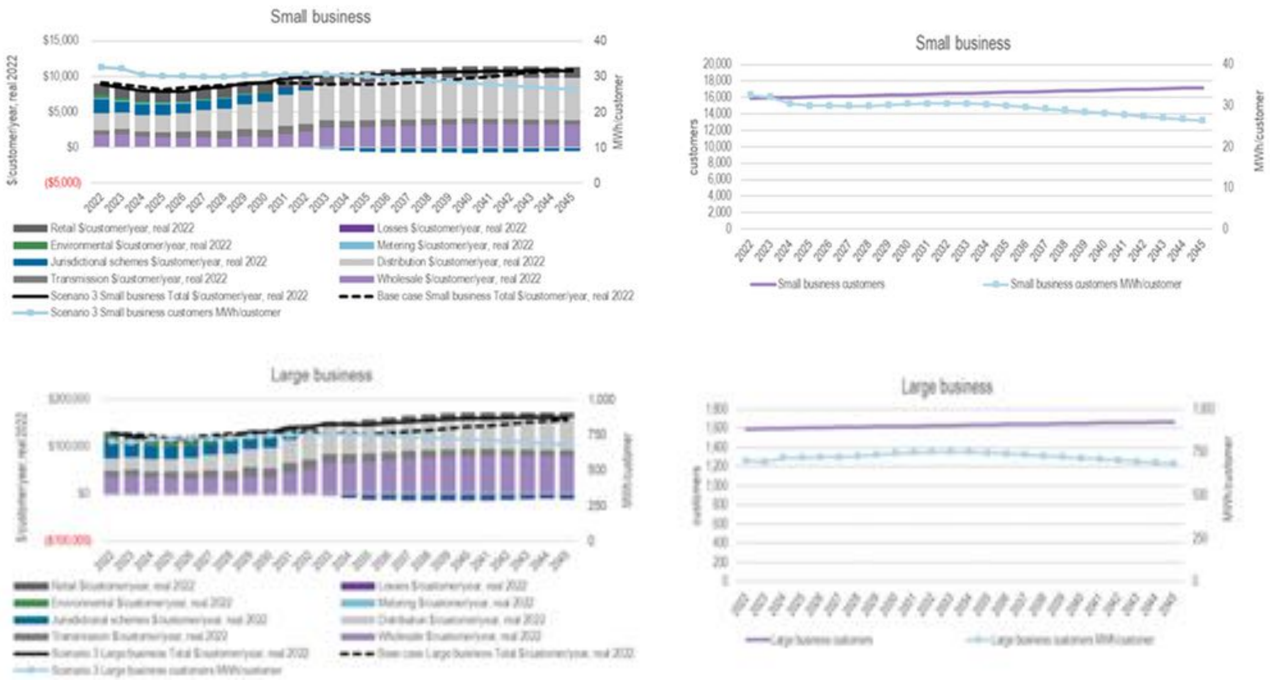
8.6.5.1 Retail bill using AER customer classes

This section discusses projected retail bills in Scenario 3 based on AER categories. Figure 164 shows projected retail bills for small and large business customers based on the AER categories. Under both the Evoenergy and AER classifications residential customers are identical.

In Scenario 3, the retail bills for small and large business customers (in real terms) are projected to increase by 21 per cent and 25 per cent respectively over the period from 2022 to 2045 (in contrast to the base case where the bills increase by 20 per cent and 21 per cent respectively). While projected bills in 2045 are very similar between the base case and Scenario 3, the pathway to this point is slightly different. Similar to Scenario 2, Scenario 3 projected average consumption per customer is lower than the base case, which offsets the higher costs to the customer (in c/kWh).

At the start of the projection period, wholesale costs comprise around 20 per cent of the small business bill, distribution costs 27 per cent, and large FiT costs 23 per cent. By 2045, wholesale costs grow to 30 per cent of the residential bill, distribution costs grow to 56 per cent and large FiT costs decline to around four per cent. A similar trend is projected for the large business bill, except that in 2045 wholesale costs grow to a larger proportion (50 per cent) and distribution costs to a lesser proportion (44 per cent) of the total bill.

Figure 164 ***Projected retail bill (left chart), by component, of small and large business customers ($/customer/year, real 2022) (LHS) and projected consumption per customer (MWh/customer) (RHS); Projected customer numbers (right chart)***



Source: ACIL Allen

8.7 Costs and benefits to ACT economy

As per Scenarios 1 and 2, the transition of the ACT energy system under the alternative decarbonisation scenarios will come with a range of costs and benefits compared to the base case. This section presents the change in costs related to increasing renewable electricity usage, along with a range of benefits associated with reductions in gas, petrol and diesel usage and their associated costs in Scenario 3. In addition, there will be extra reduction in GHG emissions under the alternative decarbonisation scenarios compared to the base case.

Table 19 summarises the various direct costs and benefits of Scenario 3 compared to the base case.

8.7.1 Costs

In total, there are expected to be an additional $10.1 billion in costs (with a net present value of $4.4 billion, using a seven per cent real discount rate (NPV7)) associated with the increased electricity usage. This is substantially higher than the estimated costs in Scenarios 1 and 2, driven largely by the need to undertake significant upgrades and changes to the electricity network to ensure security of supply whilst the rapid transition away from gas occurs. Compared to the base case, this comprises:

- $7,978 million (or NPV7 of $3,262 million) of additional capital expenses associated with upgrading the ACT electricity network (taken from the RAB figures – worst-case estimates).
- $1,270 million (or NPV7 of $669 million) of additional capital expenses associated with installing large scale and community batteries (with capital costs in each year taken from *PowerMark*).
- $1,295 million (or NPV7 of $746 million) of additional capital expenses associated with behind the meter residential and commercial rooftop PV systems and battery storage (with capital costs in each year taken from *PowerMark*).
- $951 million (or NPV7 of $405 million) of additional vehicle purchase costs associated with buying ZEVs instead of conventional and hybrid ICE vehicles. (Note, that this upfront cost is offset by reduced petrol and diesel purchases which are included in (10) below.).
- $7.1 million (or NPV7 of $5.7 million) of additional purchase and installation costs for converting gas appliances to electric.
- -$1,447 million (or NPV7 of -$707 million) of additional retail electricity costs for consumers. That is, in Scenario 3, there is a net reduction in the total cost of electricity purchased from the grid by consumers. This is driven by the large uptake of behind the meter generation and storage. For consistency in presentation with the other scenarios, this electricity line item has been grouped with the other electricity costs.
- No costing of the energy efficiency improvements has been undertaken, but the benefits are included in (6). Scenario 3: *Policy drives change*, assumes a strong and sustained suite of government measures for energy efficiency, and rapid improvements in efficiency standards, which leads to high energy savings of around an additional 880 GWh by 2045 (315 GWh or around 80 per cent more energy savings than the base case).

8.7.2 Benefits

In terms of benefits, Scenario 3 is expected to save ACT consumers $4.4 billion (or NPV7 of $1.6 billion) in gas and fuel costs compared to the base case. This is substantially higher than the estimated benefits in Scenarios 1 and 2, driven largely by the reduction in gas usage (which goes to zero by 2035). This comprises savings of:

- $56.7 million (or NPV7 of $24.3 million) of reduced capital expenditures related to maintaining the gas network (from the assumptions underlying the retail pricing model for the gas market projections).
- $2,185 million (or NPV7 of $789 million) of reduced gas purchases by ACT consumers.
- $1,923 million (or NPV7 of $708 million) of reduced petrol and diesel expenses related to running ZEVs in Scenario 3 instead of ICE vehicles in the base case.
- $218 million (or NPV7 of $80 million) of reduced human health costs associated with a reduction in noxious emissions from ICE vehicles as a result of the increased uptake of ZEVs in Scenario 3 compared to the base case.

8.7.3 Net cost and GHG emissions

The net change in the direct costs of Scenario 3 compared to the base case is estimated to be +$5,672 million (or NPV7 of +$2,779 million). Note that this costing does not include the cost of achieving the 880 GWh of energy efficiency improvements by 2045 (which are around 80 per cent more than in the base case).

In addition to the benefits discussed above, Scenario 3 will also result in a reduction of GHG emissions over the period to 2045 of 5,012 kt CO_2-e compared to the base case, which is more than double the additional GHG emissions reduction achieved in Scenarios 1 and 2. This reduction in GHG emissions comprises:

- A reduction of 1,690 kt CO_2-e associated with reduced fuel use in passenger vehicles. This is based on the emission intensity of fuels as per DITRDC (2021).
- A reduction of 3,322 kt CO_2-e associated with reduced gas use in the ACT (taken from the gas market projections).
- No change in GHG emissions associated with the additional electricity consumed (as per Scenarios 1 and 3).

8.7.4 Implied emissions abatement cost

Comparing the net cost of Scenario 3 to the base case with the reduction in GHG emissions, it is possible to calculate the implied emission abatement cost. As per (E) in Table 19, the total undiscounted net cost of Scenario 3 implies a GHG emission abatement cost of +$1,132/t CO_2-e, with an NPV7 abatement cost of +$554/t CO_2-e.

Table 19 Costs and benefits of Scenario 3, relative to the base case

		Total	NPV4	NPV7	NPV10
	Description	real A$m	real A$m	real A$m	real A$m
	COSTS				
	Additional CAPEX (relative to the base case)				
1	Electricity network and distribution	7,977.9	4,449.6	3,261.6	2,529.2
2	Grid connected batteries	1,270.0	816.9	669.4	594.0
3	Behind the meter PV and batteries	1,295.5	874.0	745.8	614.1
4	ZEVs cost premium	951.2	536.5	404.6	312.4

		Total	NPV4	NPV7	NPV10
	Description	real A$m	real A$m	real A$m	real A$m
5	Appliances (net)	7.1	6.0	5.7	5.6
6	Net additional retail electricity cost	-1,447.1	-883.3	-701.1	-580.9
7	Energy efficiency capital expenses	*Not costed*	*Not costed*	*Not costed*	*Not costed*
A	Total change in costs [=1+2+3+4+5+6+7]	10,054.7	5,799.8	4,380.2	3,474.4
	BENEFITS				
8	Reduced gas network and distribution CAPEX	56.7	32.6	24.3	19.1
9	Net reduction in retail gas cost	2,185.1	1,127.4	789.3	568.5
10	Reduced vehicle retail fuel cost	1,922.7	979.4	707.6	509.3
11	Reduced vehicle human health costs	218.4	110.9	80.1	57.4
B	Total benefits (excl. GHG) [=8+9+10+11]	4,382.9	2,250.4	1,601.2	1,154.3
C	Net change in costs (relative to the base case) [=A-B]	5,671.7	3,549.4	2,778.9	2,320.1
	REDUCTION IN GHG EMISSIONS	kt CO_2-e	kt CO_2-e	kt CO_2-e	kt CO_2-e
12	Reduced vehicle fuel use	1,689.5	1,689.5	1,689.5	1,689.5
13	Reduced gas use	3,322.5	3,322.5	3,322.5	3,322.5
14	Changes in electricity consumption	0	0	0	0
D	Total reduction in GHG emissions [=12+13+14]	5,012.0	5,012.0	5,012.0	5,012.0
		\$/t CO_2-e	\$/t CO_2-e	\$/t CO_2-e	\$/t CO_2-e
E	Implied abatement cost [=C/(D/1000)]	1,131.6	708.2	554.5	462.9

Note: All dollars are in real 2022 terms. Pricing for (6) Net electricity costs, excludes the pass through of capital expenditure (1) to customers. The additional cost of (2) Grid connected batteries, includes additional annual fixed operating and maintenance costs. There is no change in emissions from electricity given the policy of purchasing 100% renewable electricity.

Source: ACIL Allen

8.8 ACT economy-wide analysis

This Section presents the projected macroeconomic impacts using CGE modelling (as detailed in the discussion at Scenario 1).

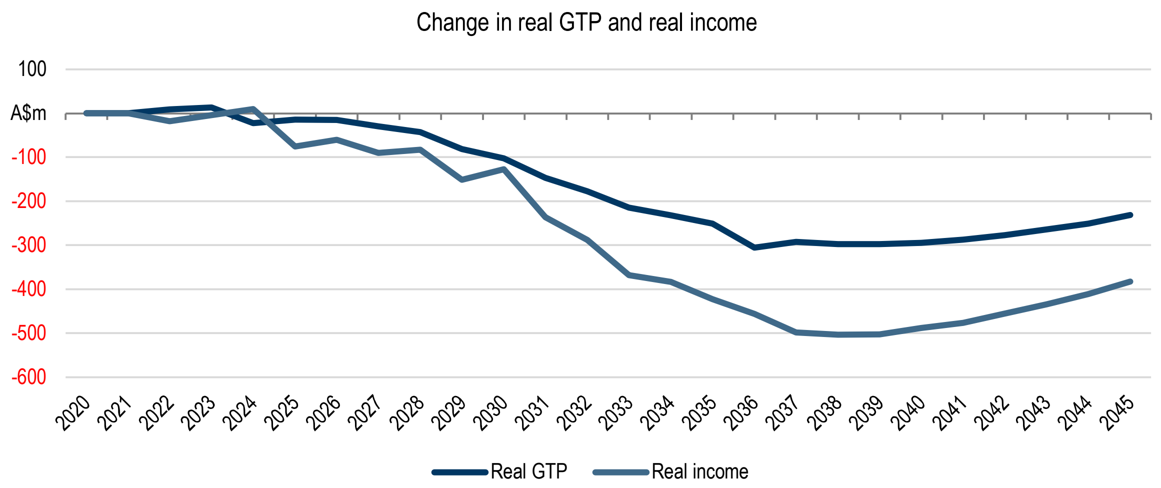
8.8.1 Macroeconomic impacts

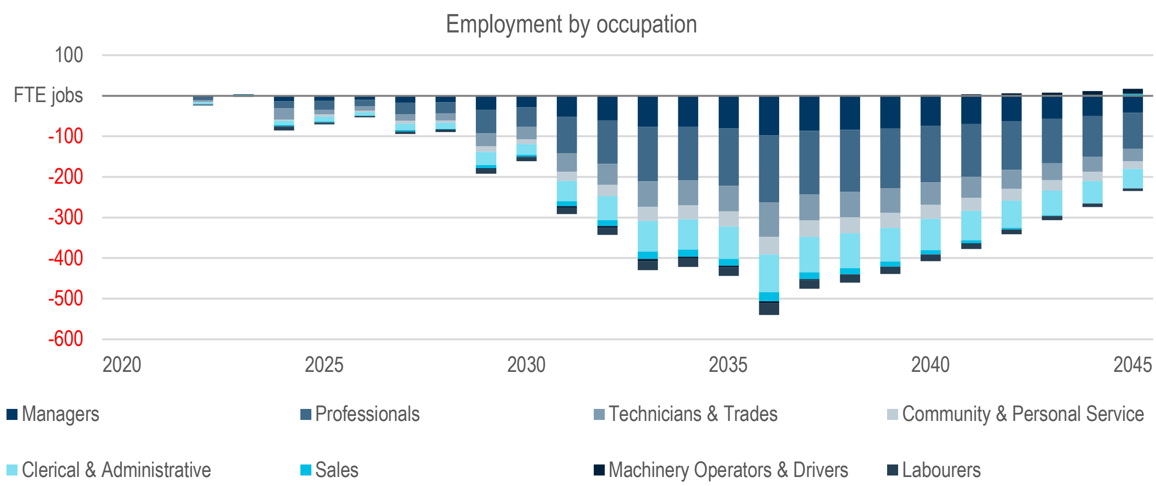
Figure 165 presents the annual macroeconomic and employment impacts of Scenario 3, relative to the base case while Table 20 presents the cumulative impacts over the period to 2045.

As can be seen, there are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, electricity prices and volumes, gas prices and volumes, and vehicle fuel purchases. In total, over the period to 2045 the cumulative difference of Scenario 3 relative to the base case is:

- -$4,106 million (or NPV7 of -$1,390 million) change in the real GTP of the ACT while initially there is little net impact due to the large additional capital program, it is negative in the longer term due to the higher consumer prices (particularly for non-residential customers) and the longer-term cost of the investment relative to the benefits and the crowding out of other investments
- -$6,910 million (or NPV7 of -$2,397 million) change in the real income of ACT residents
- -6,510 FTE employee years of employment (annual average change of -260 FTE jobs a year) in line with the lower real income.

Figure 165 Annual macroeconomic impacts of Scenario 3, relative to the base case





Source: ACIL Allen

Table 20 Total macroeconomic impacts of Scenario 3, relative to the base case

	Total	NPV4	NPV7	NPV10
	real A$m	real A$m	real A$m	real A$m
Real economic output (GTP)	-4,106.0	-2,527.1	-1,390.0	918.7
Real income	-6,910.5	-4,289.6	-2,397.3	-1,610.1
	Total	**Annual average**		
	FTE jobs	FTE jobs		
Employment	-6,510	-260		

Note: All dollars are in real 2022 terms.

Source: ACIL Allen

9. Comparative analysis

This Chapter explores the key differences in relation to the outcomes under each scenario.

9.1 Scenario analysis

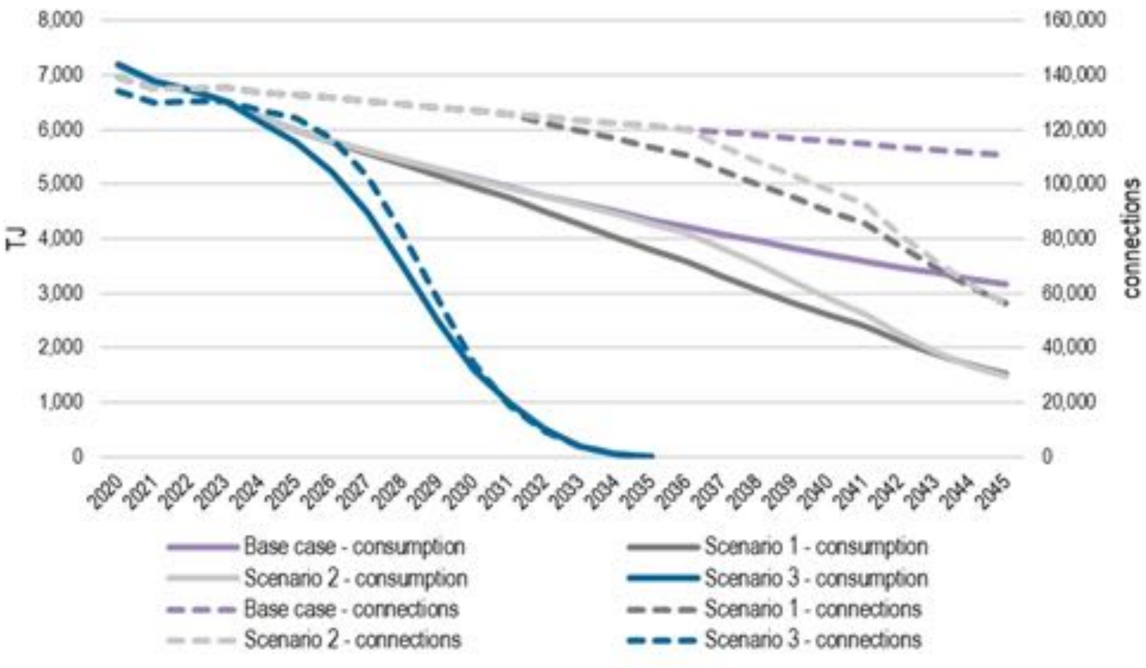
9.1.1 Gas market

9.1.1.1 Gas network demand

The base case sees gas demand from the network drop by 60 per cent, driven by a combination of lower consumption per connection and less connections (as some customers move to electrify). There is no overall network growth given Government policy. Scenarios 1 and 2 look to increase this downwards trend resulting in an 80 per cent reduction in gas demand by 2045. Under Scenario 2, the decrease follows the base case trajectory until 2035 (to bolster the economic viability of the network until them), but then falls away more rapidly (in comparison to Scenario 1).

Scenario 3 sees the natural gas network close by 2035. The majority of consumers leave the network by 2033, with the remaining few customers transitioning over the following two years. Figure 166 shows gas consumption under each scenario.

Figure 166 Projected total gas consumption and connections – all scenarios



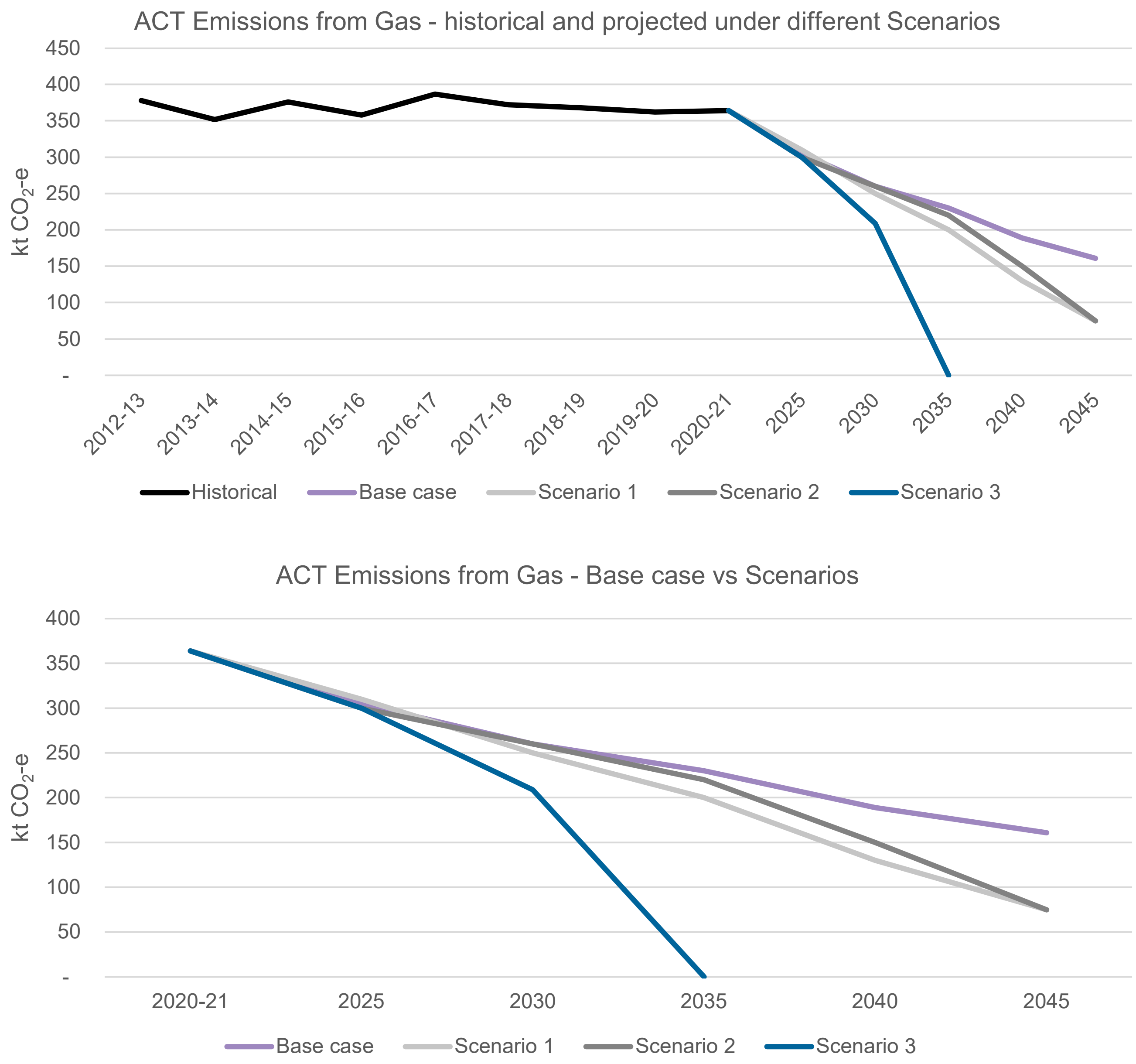
Source: ACIL Allen

9.1.1.2 Gas related emissions

Figure 167 shows the potential reduction in emissions from natural gas network for the base case and each scenario (the top figure includes historical emissions). Scenario 1 and Scenario 2 show a significant gain in comparison to the base case, with both generating an additional cut in emissions of around 85 kt by 2045 (albeit Scenario 1 realises these additional cuts at a faster rate initially).

Scenario 3 sees emissions from the natural gas network reducing more rapidly and falling to zero from 2035. However, it is anticipated that there will be some continuing use of gas following the closure of the gas network in 2035. There will be some residual gas use by customers unable to electrify and some industrial use as a feedstock or where electric equipment options may be limited/unavailable. Biogas or hydrogen may provide suitable low emission alternatives, and if green gas is not a practicable alternative, offsets will need to be purchased to deliver on the Territory's net zero goals (offset costs are not factored into the modelling).

Figure 167 ACT natural gas related emissions



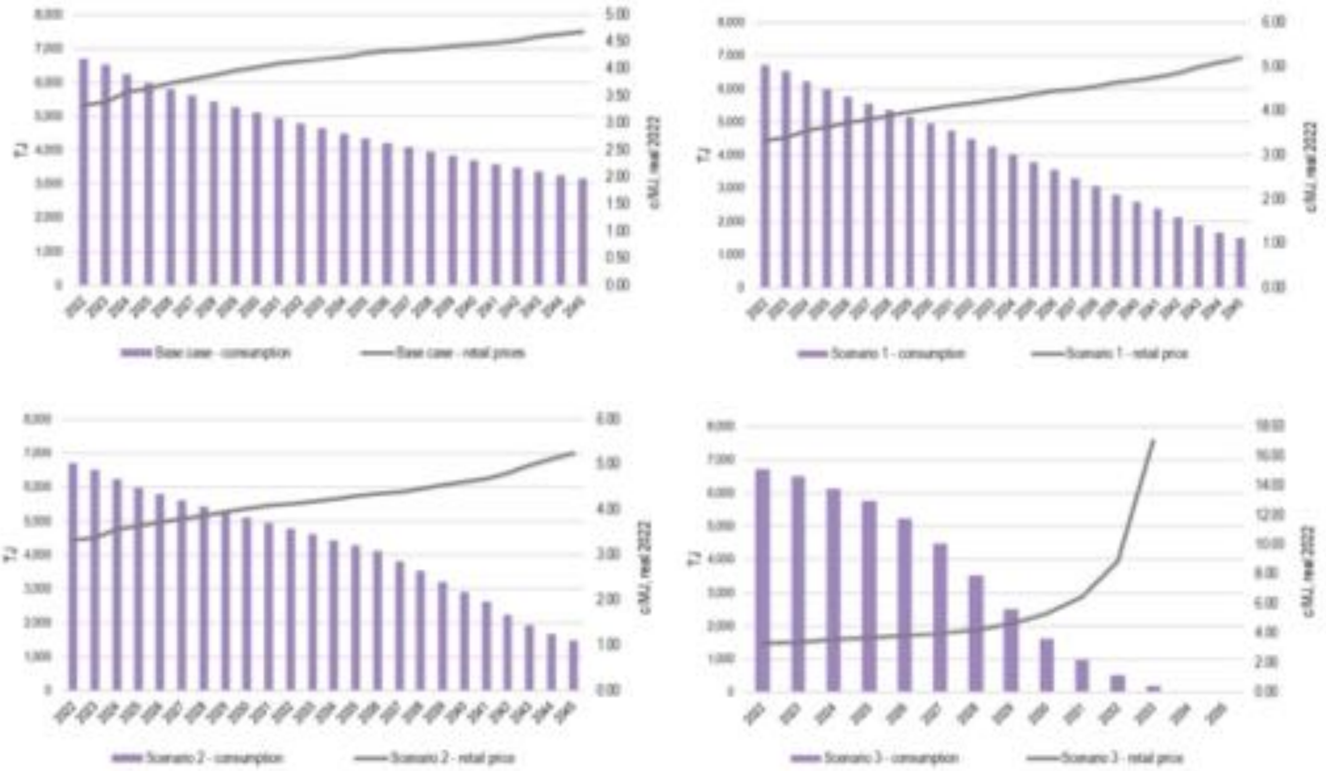
Source: ACIL Allen, GHD

9.1.1.3 Gas pricing

The base case delivers the smallest impact on gas prices with retail prices increasing from around $3.3 cents/MJ to around $4.5 cents/MJ by the mid-2040s (approximately 35 per cent). Scenarios 1 and 2 both exhibit a higher price rise, close to 60 per cent. This is primarily driven by the projected increase in distribution tariffs under both scenarios.

As shown in Figure 168, retail prices under Scenario 3 are similar to other scenarios until the mid-2020s, after which they rapidly escalate (by 2032 prices will have tripled).

Figure 168 Projected total retail gas prices and consumption – all scenarios



Source: ACIL Allen

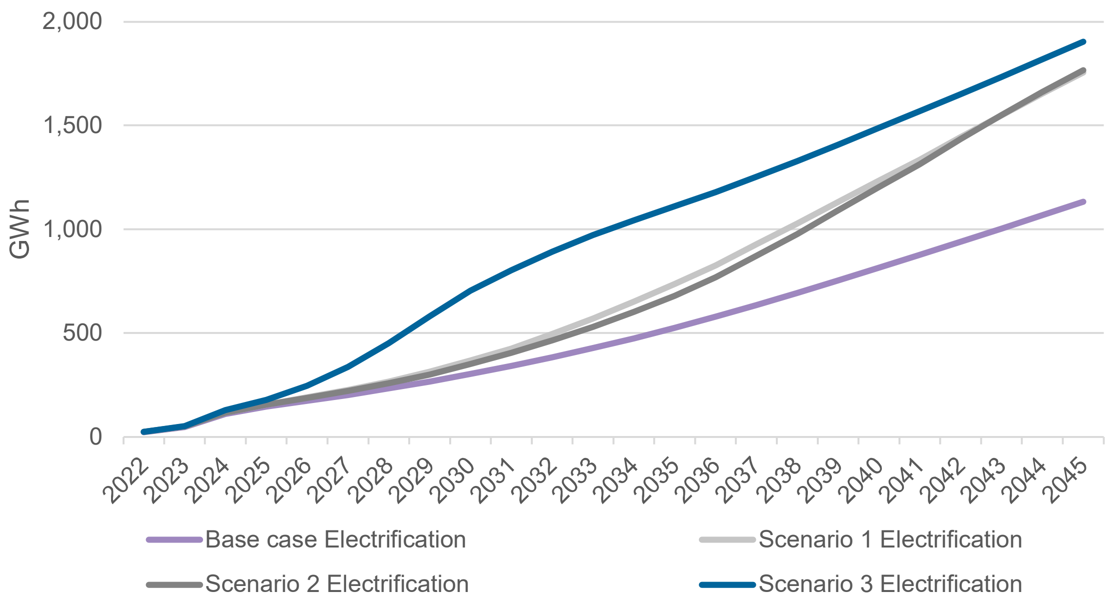
9.1.2 Electricity market

9.1.2.1 Electrification

The falling demand for gas from the gas network and the uptake of ZEVs under the base case and scenarios drives electrification as shown in Figure 169.

The base case and Scenarios 1 and 2 follow similar trajectories to 2030, with Scenarios 1 and 2 accelerating after 2030 due to higher ZEV uptake and faster gas conversion. Scenario 3 brings forward electrification needs much earlier with rapid change during the period 2025-32 aligning with the rapid drop in gas consumption during this time.

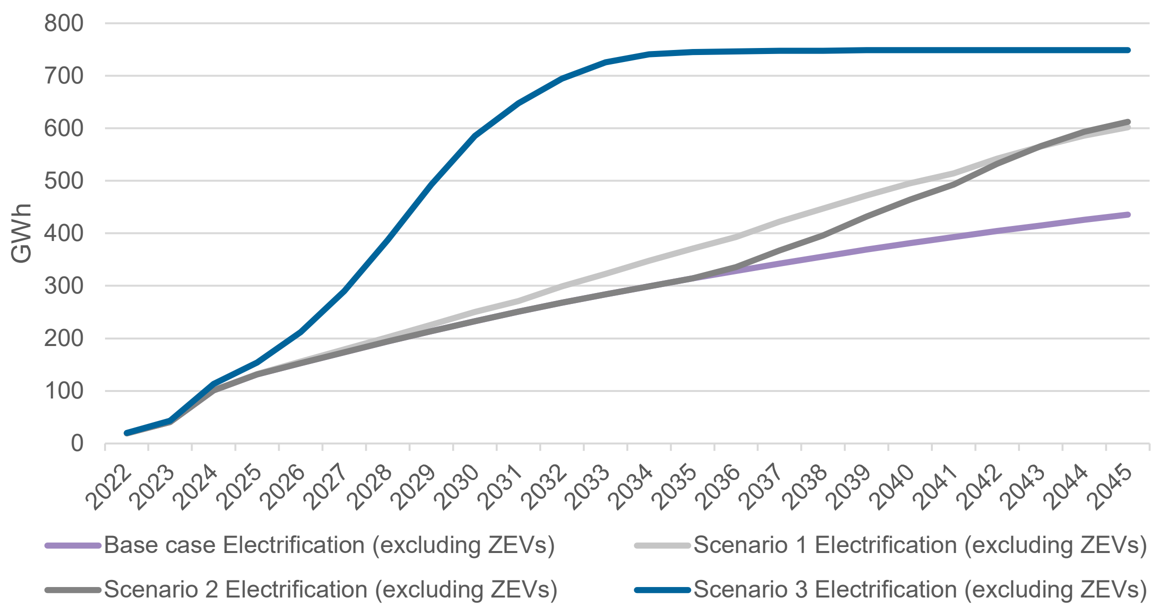
Figure 169 *Electrification demand– all scenarios*



Note: Electrification includes electricity demand from ZEVs and gas customer switching
Source: ACIL Allen

Figure 170 shows electrification demand from gas conversion only.

Figure 170 *Electrification demand from gas conversion – all scenarios*



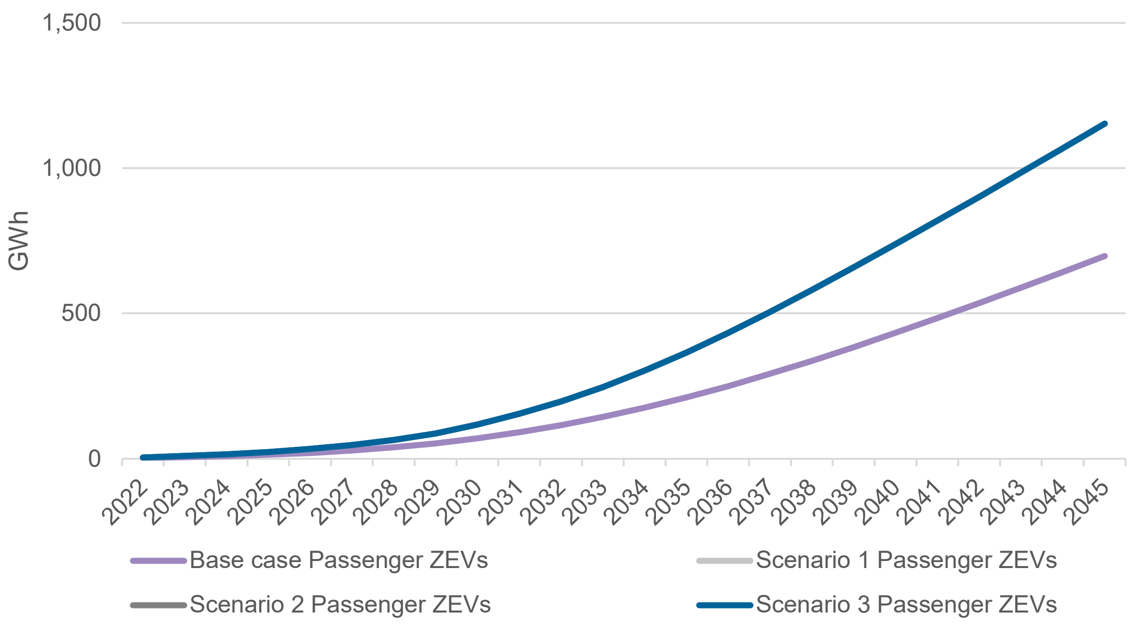
Note: This chart shows electricity demand from gas customer switching and excludes ZEVs
Source: ACIL Allen

9.1.2.2 ZEV emissions - impact underestimated

All three scenarios use the same assumptions concerning the deployment of EVs (the base case assumes 41 per cent of the fleet are ZEVs by 2045; this grows to 68 per cent under each of the scenarios). The deployment of ZEVs creates additional grid demand (see Figure 171) which is offset to varying degrees by PV penetration, battery deployment and use of ZEVs for V2G and V2H purposes. This in turn factors into the Government's 100 per cent renewal electricity requirements and the extent to which the purchase of renewable electricity is required.

This highlights the risk of looking at the electricity system in isolation, even with gas projections taken into consideration. As highlighted in the **Base case Report,** transport emissions account for around 57 per cent of the Territory's overall emissions.[37] The relatively small impact ZEVs have on electricity demand and subsequent action necessary to maintain the 100 per cent renewable target is disproportionate to the decrease in transport emission of the order of 50-60 per cent under all three scenarios arising from ZEV roll-out. A holistic view examining emissions from all sources and their interactions is essential to understanding the ACT's transition to a net zero emissions society.

Figure 171 ZEV impact on electricity demand – all scenarios



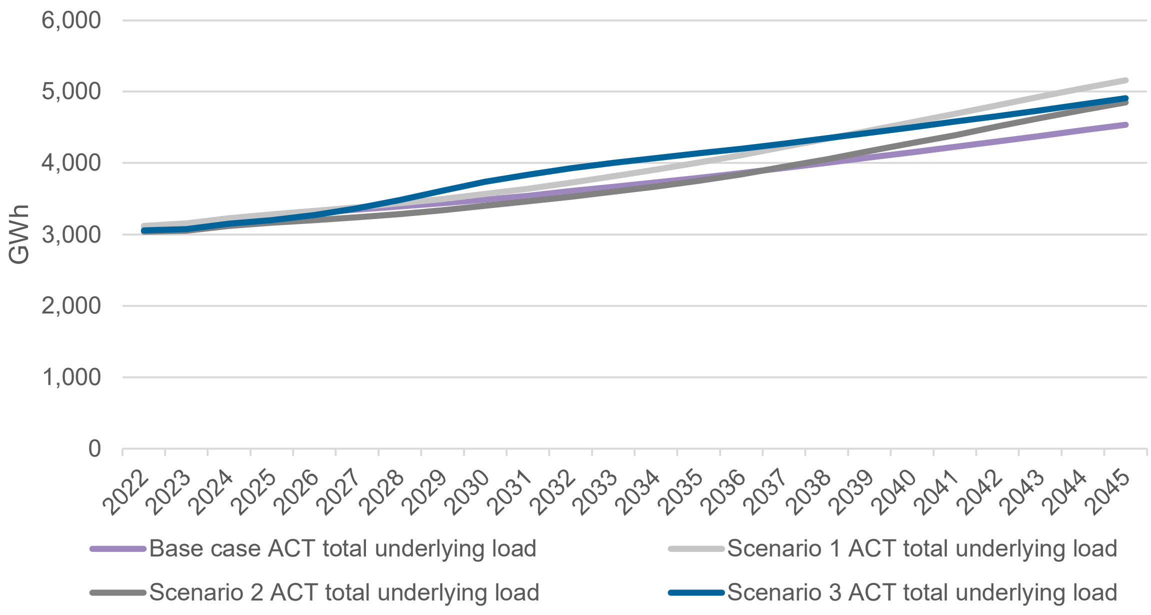
Note: ZEV impact on electricity demand in Scenarios 1, 2 and 3 are identical.
Source: ACIL Allen

9.1.2.3 Electricity demand

Figure 172 shows the underlying total load[38] for all scenarios. The base case results in the lowest underlying load by 2045. All scenarios follow similar upward trajectories reflecting the additional demand due to ZEV uptake and the transition away from gas (even though Scenario 3 rises more sharply in the early years as the gas network moves towards closure in 2035). Scenario 1 has the highest final load, reflecting lower levels of energy efficiency in this scenario.

[37] Strategy. Policy. Research: "ACT Greenhouse Gas Inventory for 2019-20", October 2020
[38] Underlying load (or underlying energy requirements or underlying demand) is defined as 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.

Figure 172 Underlying load – all scenarios



Source: ACIL Allen

The difference between the scenarios is starker when considering grid demand (see Figure 173Figure 176).[39]

The three scenarios all result in reduced demand from the grid compared to the base case for the majority of the period, with only Scenario 1 resulting in greater demand for the final three years of the projection period.

Both the base case and Scenario 1 trend upwards reflecting overall energy requirements, albeit Scenario 1 rises at a slower rate, reflecting greater PV deployment. Grid demand under both Scenarios 2 and 3 remain essential flat with demand offset by greater PV penetration and energy efficiency improvements.

The accelerated impact of the phase out of gas by 2035 is clearly seen in the convex ‘bump’ in the Scenario 3 trace.

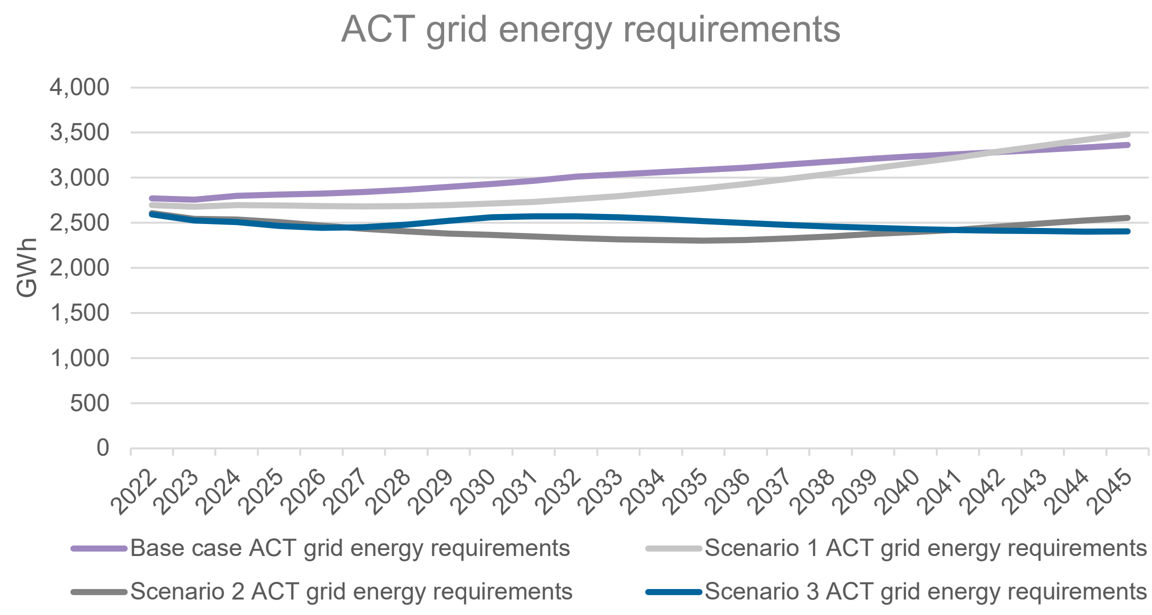
Peak demand is projected to follow a similar trajectory to the base case in the scenarios, with additional peak demand growth (above the base case) occurring due to higher levels of gas transition.

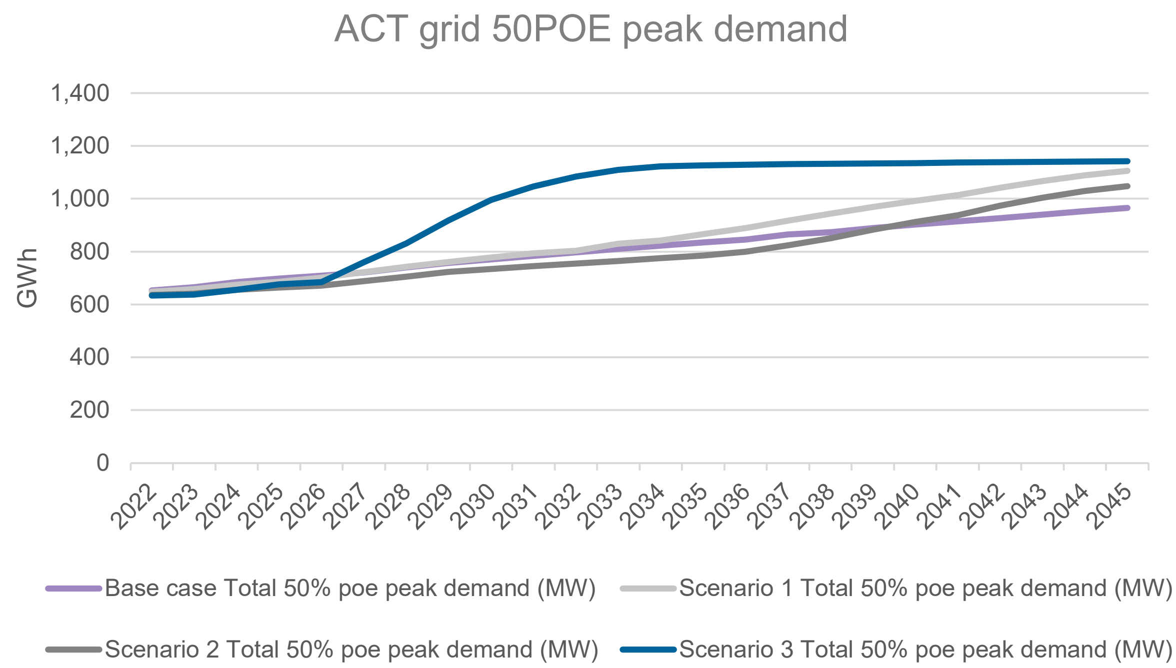
In Scenario 3, this occurs much earlier (from around 2027), while under Scenarios 1 and 2 it occurs later in the period.

The growth in peak demand in all scenarios is predominantly driven by electrification of space heating requirements during winter mornings. Home batteries are assumed to charge during the middle of the day and discharge during the evening peak (which addresses much of the demand from electrification of space heating requirements during winter evenings). V2H batteries also discharge to meet some of the morning space heating requirements.

[39] Grid demand (or grid energy requirements) is defined as all the electricity sourced from the grid, at the point of the consumer’s meter. Energy requirement (demand) is the total amount of electricity consumed over a period (in this case, a year) and is measured in gigawatt hours (GWh). Peak demand refers to the maximum amount of electricity used at any one time (in this case, a half hour period) and is measured in megawatts (MW). 50 ‘probability of exceedance’ (POE) refers to the median or middle value in a range of peak demand outcomes that could be expected to occur.

Figure 173 Projected total annual grid energy requirements and annual grid peak demand – all scenarios vs base case





Note: Grid energy requirements and grid peak demand refers to the electricity sourced from the grid, measured at the point of the consumer's meter.
Source: ACIL Allen

9.1.2.4 Maintaining the 100 per cent renewable electricity commitment

The base case and all three scenarios all incorporate a third auction in 2025, which is assumed to be two 200 MW wind farms in NSW to ensure the Government can continue to deliver it commitment to 100 per cent renewable electricity. Taking into account the current policy, which allows renewable electricity in excess of the 100 per cent target to be 'banked', with credits carrying over to future years, all scenarios 'deliver' against the commitment (see Figure 174), with the base case falling slightly short at the end of the period.

While the base case falls short from 2043, the NEM is projected to source more of its generation from renewables over time which will more than offset the shortfall (if the policy is changed to allow the NEM's contribution to be considered). Furthermore, a policy change of this nature would allow reconsideration of the timing and magnitude of the 2025 auction, particularly under Scenarios 2 and 3.

Figure 174 ***Meeting the 100% renewable electricity commitment – all scenarios***

Source: ACIL Allen

Network augmentation

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

- investment is primarily driven by growth in network demand due to ACT population growth and, to a lesser extent, the forecast dependence on electricity for heating in the absence of gas, and the recharging of ZEVs
- growth in demand will be offset, to varying degrees, by improvements in energy efficiency and increased penetration of rooftop PV systems, coupled with batteries
- in the base case investment will be 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 comparison of changes in the network RAB is shown in Figure 175 and Figure 176 below. The faster gas transition in all scenarios drives higher network investment expenditure, given additional infrastructure is required to meet the rising demands. In Scenario 3 where transition is most rapid the investment in the network is more significant than in the other cases. All cases show significant growth in DER which has contributed to the significant investment in the network to ensure that they can connect without having an adverse effect on the supply to customers.

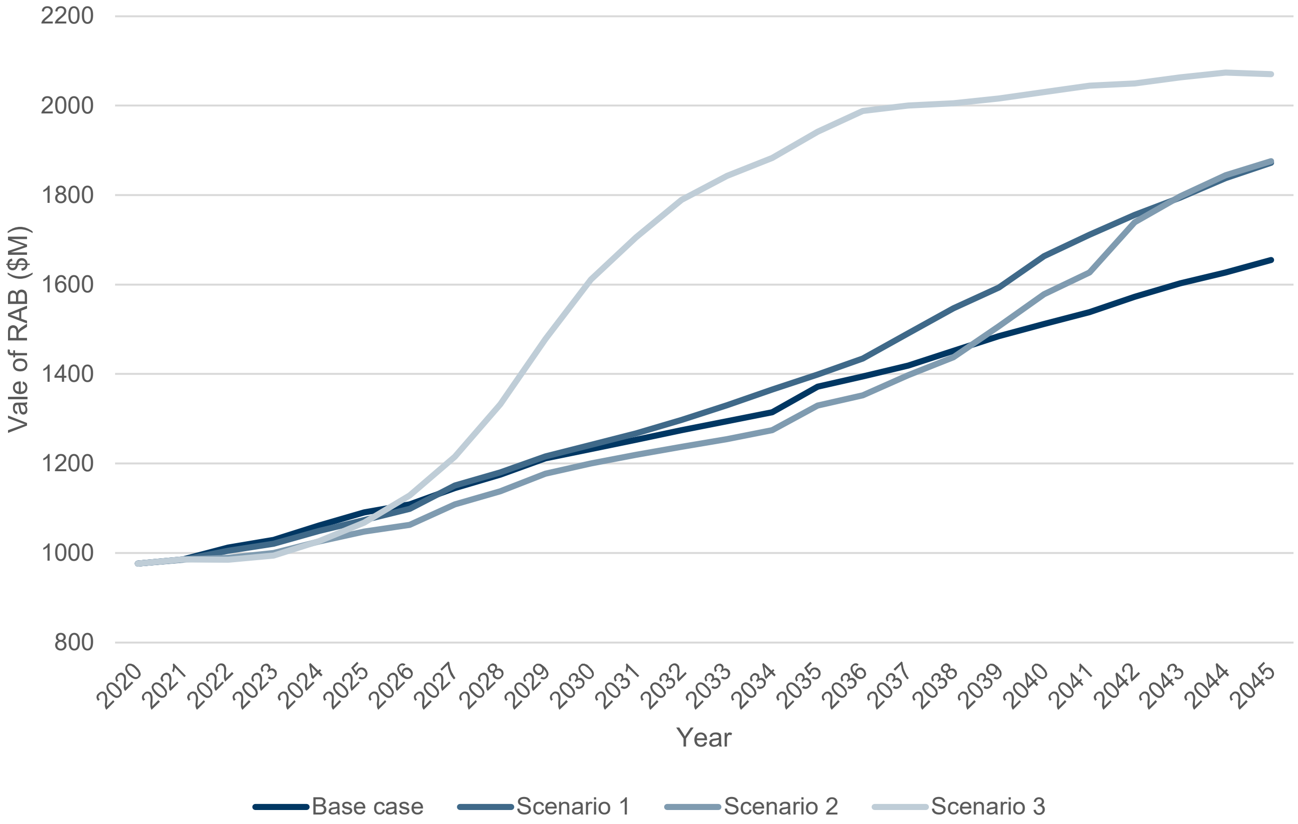
In Scenario 1 it is observed the investment in location specific investments is slightly less than the base case, this has been driven by the increase in roof top PV and batteries (both grid connected and household) slightly deferring some projects outside of the period.

Under Scenario 3, investment reduces late in the projection period, whereas under Scenarios 1 and 2 it continues to increase. The decrease in Scenario 3 is due to the significant DER and batteries somewhat flattening the peak demand. In Scenarios 1 and 2 the growth of DER and batteries have already deferred some projects by around a year as the growth in demand is not as high as Scenario 3.

Figure 175 Change in value of the distribution asset base 2020-2045, $ million

Source: GHD

Figure 176 Change in cumulative value of the distribution asset base 2020-2045, $ million over time



Source: GHD

Electricity retail bill

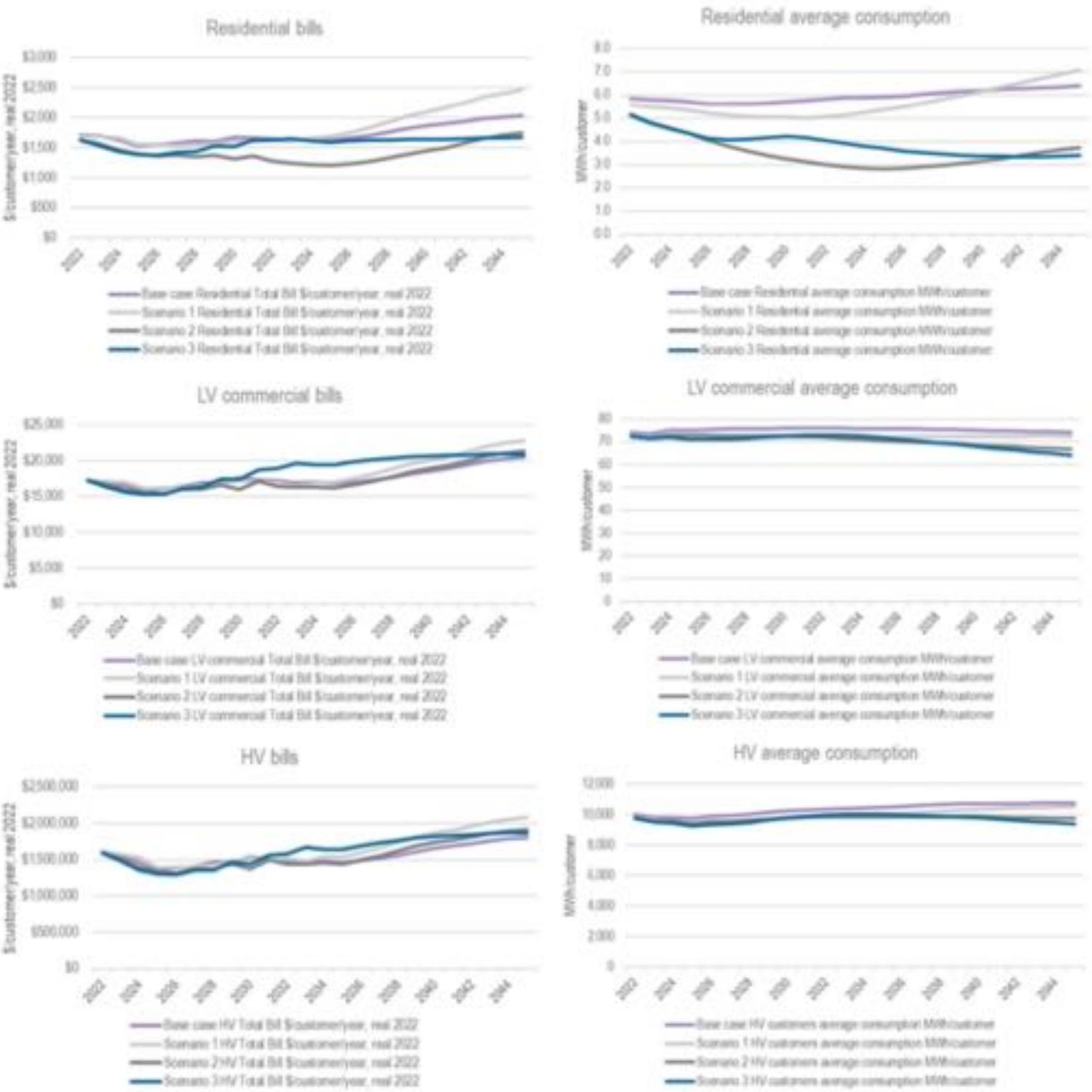
Figure 177 below shows the total retail bill by customer class (residential, commercial and HV) for the base case and each scenario.

Residential bills are projected to be lowest under Scenario 2 due to lower projected average consumption per customer (driven by higher assumed levels of energy efficiency and rooftop PV uptake), which offsets higher projected retail prices (in c/kWh) (which are primarily driven by higher wholesale and distribution network costs). Scenario 3 retail bills have similar drivers to Scenario 2 (lower average consumption offsetting the higher cost per unit of consumption). However, between around 2028 and 2042, Scenario 3 bills are higher than Scenario 2, given a significant amount of electrification is assumed to brought forward in Scenario 3.

On the other hand, residential bills are projected to be highest under Scenario 1 due to a combination of higher projected average consumption per customer and higher projected retail prices (in c/kWh). Higher projected average consumption and retail prices are the result of higher projected demand from electrification, which increases the projected cost to the residential customer (primarily via higher wholesale costs).

A similar trend is projected for LV and HV commercial bills, but to a lesser extent as a result of differences in average consumption being less pronounced for these customer types.

Figure 177 Retail bill and average consumption by customer class – all scenarios



Source: ACIL Allen

9.2 Scenario assessment

This Section assesses the relative benefits (and shortcoming) of each scenario so as to enable a choice as to the optimal pathway towards net zero. This assessment needs to be overlain with the 'tipping point' and economic impacts that follow. A summary of results is provided at Figure 178.

Base case:

- Delivers the least cost outcome in terms of gas bill impact to consumers and electricity network (RAB) upgrade investment requirements.
- Involves the lowest level of electrification and underlying electricity load, but has a high grid demand, given lower PV penetration.
- Requires the lowest level on new investment (RAB) in the grid.
- Delivers the least impact from an emissions perspective with less reduction in natural gas emissions and generates the highest pressure in terms of the need for further wind farm purchases to meet the 100 per cent renewable electricity commitment.

Scenario 1 and Scenario 2:

- Both scenarios deliver similar outcomes in terms of gas demand; reduction in natural gas emissions; bill impact on gas customers; result in similar electrification profiles; and have similar electricity network (RAB) upgrade investment requirements.
- Both require similar levels of (RAB) investment.
- Despite the level of electrification being essentially the same, Scenario 1 results in both higher underlying load and grid demand, as compared with Scenario 2. This difference is driven by the greater deployment of rooftop PV and energy efficiency improvements.
- Scenario 2 delivers better renewable electricity outcomes, along with lower retail bill impacts in comparison with to Scenario 1.

Scenario 3:

- Delivers the best emission reduction outcomes with CO_2 emissions from natural gas reducing to zero, coupled with the best overall renewable electricity delivery.
- The overall impact on electricity retail bills is on a par with the best outcomes delivered by other scenarios. Even though retail prices under Scenario 3 are some of the highest (mainly due to high distribution network costs), the low average consumption reduces the overall bill impact.
- Requires the highest level on new investment (RAB) in the grid.
- These outcomes come at a considerable cost, especially to gas consumers in the lead up to the closure of the gas network when gas prices spike.
- Furthermore, there are additional costs not encompassed in the modelling including the write-down of Evoenergy's gas network and possible Government support to 'smooth' the closure of the gas network and the transition of the last customers. While these costs are unique to Scenario 3 at this stage, they will eventually apply to all scenarios, should the natural gas network cease operations (a possibility under other scenarios). The 'tipping point' analysis will provide insights as to whether or not and when these costs might apply to Scenarios 1 and 2.

Figure 178 Benefits and results of scenarios versus base case

Projected emissions reduction								
	Base case		Technology drives change		Decentralisation is king		Policy drives change	
Projected emissions	Projected emissions reduction of 358 kt of CO_2 to 158 kt of CO_2		Projected emissions reduction of 358 kt of CO_2 to around 80 kt of CO_2.		Projected emissions reduction of 358 kt of CO_2 to around 80 kt of CO_2.		Projected emissions reduction of 358 kt of CO_2 to around 0 kt of CO_2.	
Emissions reduction % change	↓	57% fall	↓	77% fall	↓	77% fall	↓	100% fall
Projected gas consumption								
Natural gas consumption	Projected fall from 7,000 TJ to 3,0000 TJ		Projected fall from 7,000 TJ to <2,000TJ		Projected fall from 7,000 TJ to <2,000TJ		Projected fall from 7,000 TJ to 0 TJ	
Consumption % change	↓	57% fall	↓	71% fall	↓	71% fall	↓	100% fall
Gas connections	Total gas connections projected to decrease from 140,000 to 110,000		Total gas connections projected to decrease from 140,000 to 60,000		Total gas connections projected to decrease from 140,000 to 60,000		Total gas connections projected to decrease from 140,000 to 0	
Connections	↓	30,000 fall	↓	80,000 fall	↓	80,000 fall	↓	140,000 fall
Rate of switching	↑	2.5% p.a	↑	3.5% p.a	↑	3.5% p.a	↑	4%-70%
Projected demand								
ACT total grid energy requirement	Growth in total grid energy requirements from 2,772 GWh in 2022 to 3,367 GWh in 2045.		Growth in total grid energy requirements from 2,772 GWh in 2022 to 3,481 GWh in 2045.		Decline in total grid energy requirements from 2,772 GWh in 2022 to 2,553 GWh in 2045		Decline in total grid energy requirements from 2,772 GWh in 2022 to 2,486 GWh in 2045	
Percentage growth	↑	21% increase	↑	25% increase	↓	8% decrease	↓	11% decrease
Peak grid demand	Increase in peak grid demand from 654 MW in 2022 to 966 MW in 2045		Increase in peak grid demand from 654 MW in 2022 to 1,184 MW in 2045		Increase in peak grid demand from 654 MW in 2022 to 1,048 MW in 2045		Increase in peak grid demand from 654 MW in 2022 to 1,143 MW in 2045	
Peak grid growth	↑	48% increase	↑	79% increase	↑	68% increase	↑	75% increase
Projected retail price								
Total retail prices	Increase in retail prices for residential, LV commercial and HV customers		Increase in retail prices for residential, LV commercial and HV customers		Increase in retail prices for residential, LV commercial and HV customers		Increase in retail prices for residential, LV commercial and HV customers	
Retail electricity price change	↑	9% (residential), 19% (LV) and 5% (HV)	↑	14% (residential), 33% (LV) and 22 (HV)	↑	48% (residential), 35% (LV) and 21% (HV)	↑	55% (residential), 36% (LV) and 22% (HV)
Gas retail price change	↑	3.3¢/MJ to around 4.5¢/MJ	↑	3.3¢/MJ to around 5.2¢/MJ	↑	3.3¢/MJ to around 5.2¢/MJ	↑	3.3¢/MJ to around 15¢/MJ
Network investment								
Network Value (2028)	$1,654 million		$1,873 million		$1,876 million		$2,870 million	
Additional investment required	$678 million		$896 million		$899 million		$1,893 million	

9.3 Sensitivities

We have undertaken sensitivity analysis on three key parameters:

- Battery deployment
- EV market penetration
- RAB investment requirements.

These parameters were selected on the basis that they may significantly impact outcomes, constitute areas of greatest uncertainty and/or are amenable/influenced by policy/regulatory intervention.

9.3.1 Battery deployment

To test the sensitivity in relation to battery deployment, we have increased community battery storage capacity so that peak demand in 2045 is reduced by 25 MW (or 2.4 per cent) in Scenario 1, 40 MW (or four per cent) in Scenario 2 and 40 MW (or 3.6 per cent) in Scenario 3. It has been assumed that the increase in community battery storage ramps up over the projection period.

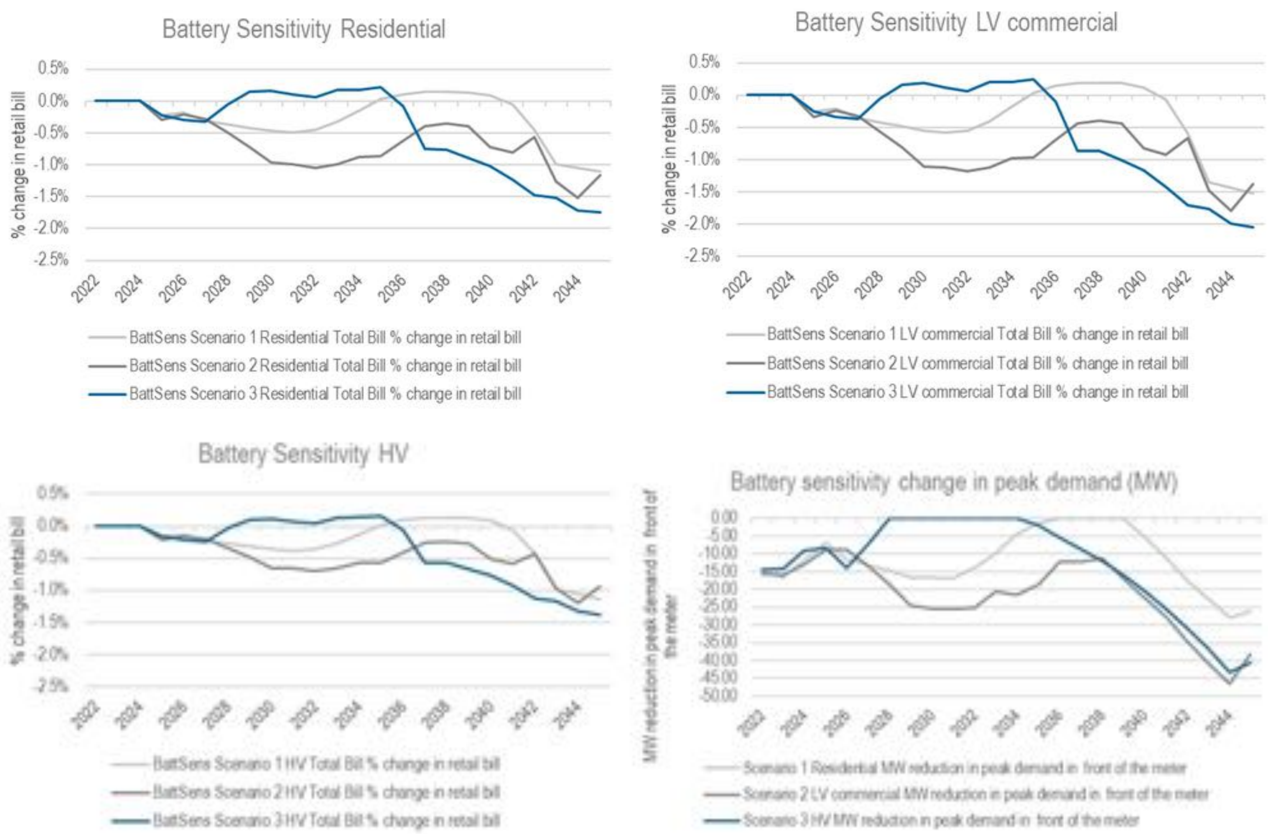
Batteries could theoretically be used in specific locations with optimised charging and discharging profiles to defer network investments and in some cases defer them to beyond 2045. However, as the size and location of the individual batteries is largely unknown, the worst-case option of the batteries being distributed around the network, proportional to the demand, has been used.

Increasing the size of the network batteries decreased peak demand which resulted in deferral of a number of investments within the investment period in all scenarios and in Scenario 2 deferred one investment planned for 2045 to outside of the period.

The increase in battery storage in this sensitivity results in a reduction in the retail bill for all customer types of around 1.5 per cent by 2045 (see Figure 179). The impact on the retail bill reflects the reduction in peak demand and the resulting change in the distribution component of the retail tariff.

The analysis shows that the deployment of additional batteries located across the distribution network will both lower peak demand and reduce retail bills. The reduction in bills presented here is conservative, given it is assumed that the batteries are distributed evenly across the network. In theory, optimising the location and operation of the batteries in the network should result in greater savings in bills due to deferred network investment.

*Figure 179 **Battery sensitivity all scenarios – retail bill impact by customer and change in peak demand (MW)***



Note: % change in retail bill is measured as the difference between the scenario and the sensitivity retail bills. Change in peak demand is measured ‘in front of the meter’, given that is where the batteries are assumed to be located.
Source: ACIL Allen

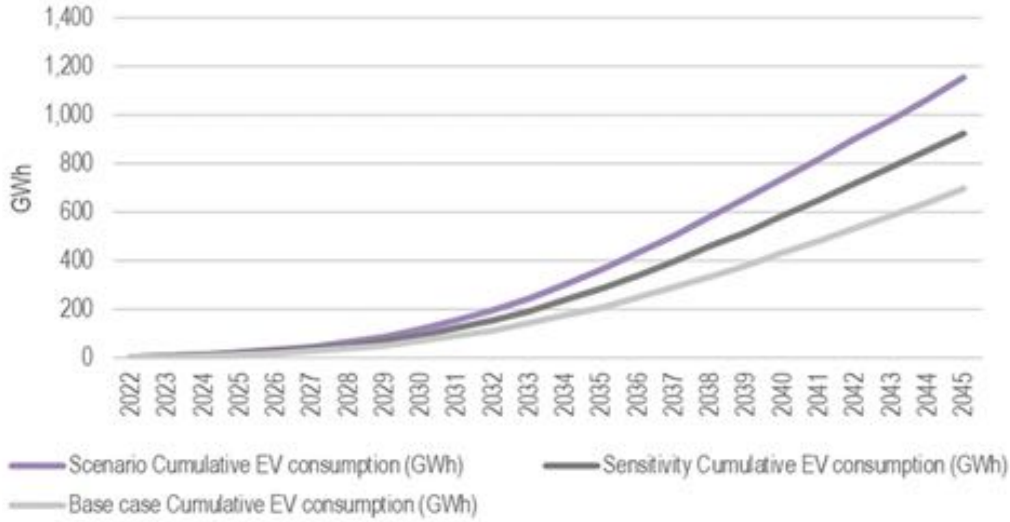
9.3.2 EV market penetration

To test the sensitivity in relation to EV market penetration, we have assumed the energy requirements for EVs are around 20 per cent lower[40] than that required under Deloitte’s ‘optimistic’ EV uptake projections assumed in all three scenarios. The scenarios assume ZEV uptake reaches 68 per cent by 2045, compared to 41 per cent in the base case. This falls mid-way between the base case and the scenarios, as shown in Figure 180. This translates to a decrease in total ACT grid energy requirements and 50POE peak demand of around six per cent and one per cent, respectively.

Decreasing the growth of EVs decreased the growth in maximum demand which resulted in deferral of a small number of investments within the investment period in all scenarios and in Scenario 2 deferred one investment planned for 2045 to outside of the period.

[40] Equivalent to a reduction of around 53,000 ZEVs by 2045 (as compared to the optimistic projection).

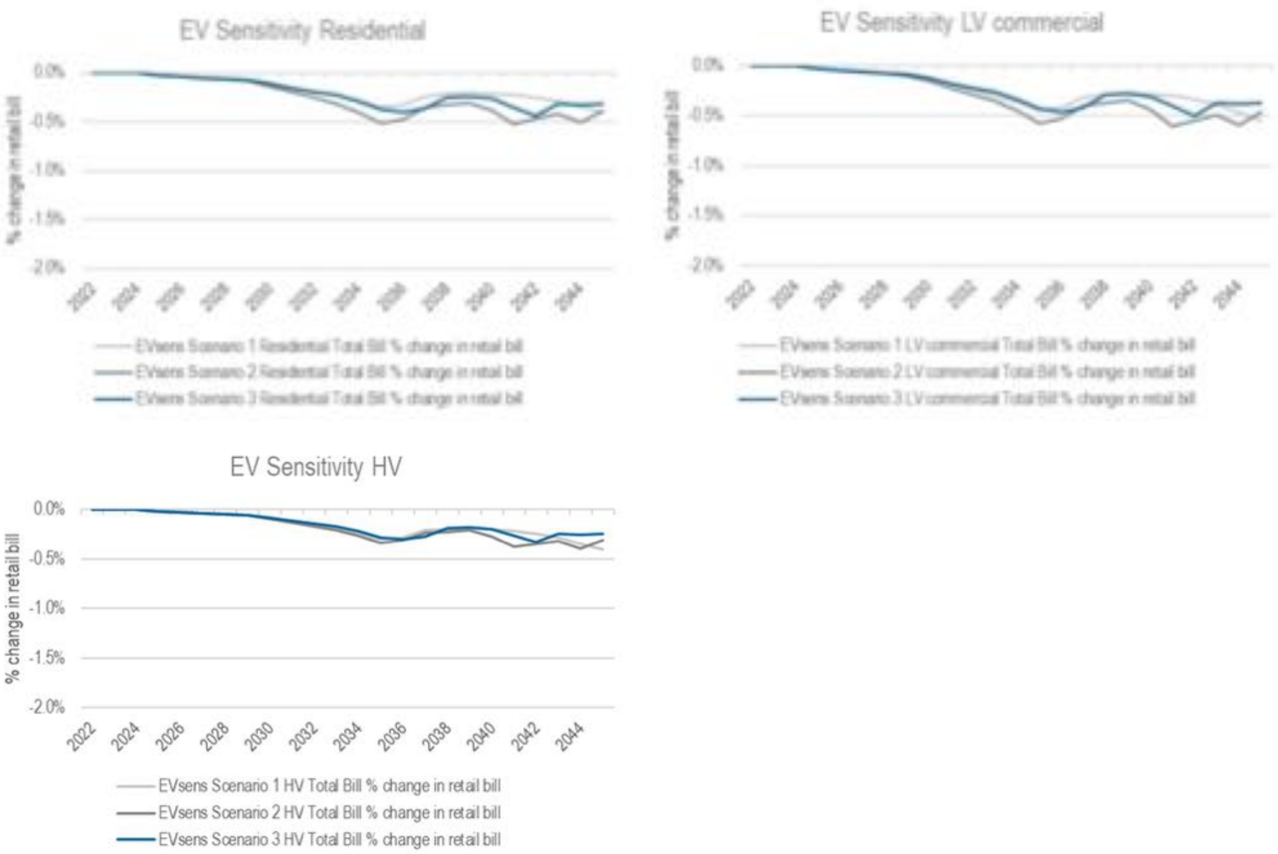
Figure 180 Cumulative EV consumption (GWh)



Source: ACIL Allen

In all scenarios, a 20 per cent reduction in energy requirements for EVs results in a very small reduction in the retail bill for all customer types, ranging between 0.1 per cent and 0.5 per cent from 2030 to 2045. The impact on the retail bill reflects the reduction in total ACT grid demand and the resulting change in the distribution component of the retail tariff. The analysis suggests that EV penetration rates are a policy lever the Government can draw on with the knowledge that it will not impact retail bills to any discernible level and only modestly impact ACT grid energy requirements. However, in terms of overall CO_2 emissions reductions from liquid fuels the impact will be significant.

Figure 181 EV sensitivity all scenarios – retail bill impact by customer



Note: % change in retail bill is measured as the difference between the scenario and the sensitivity retail bills
Source: ACIL Allen

9.3.3 RAB investment requirements

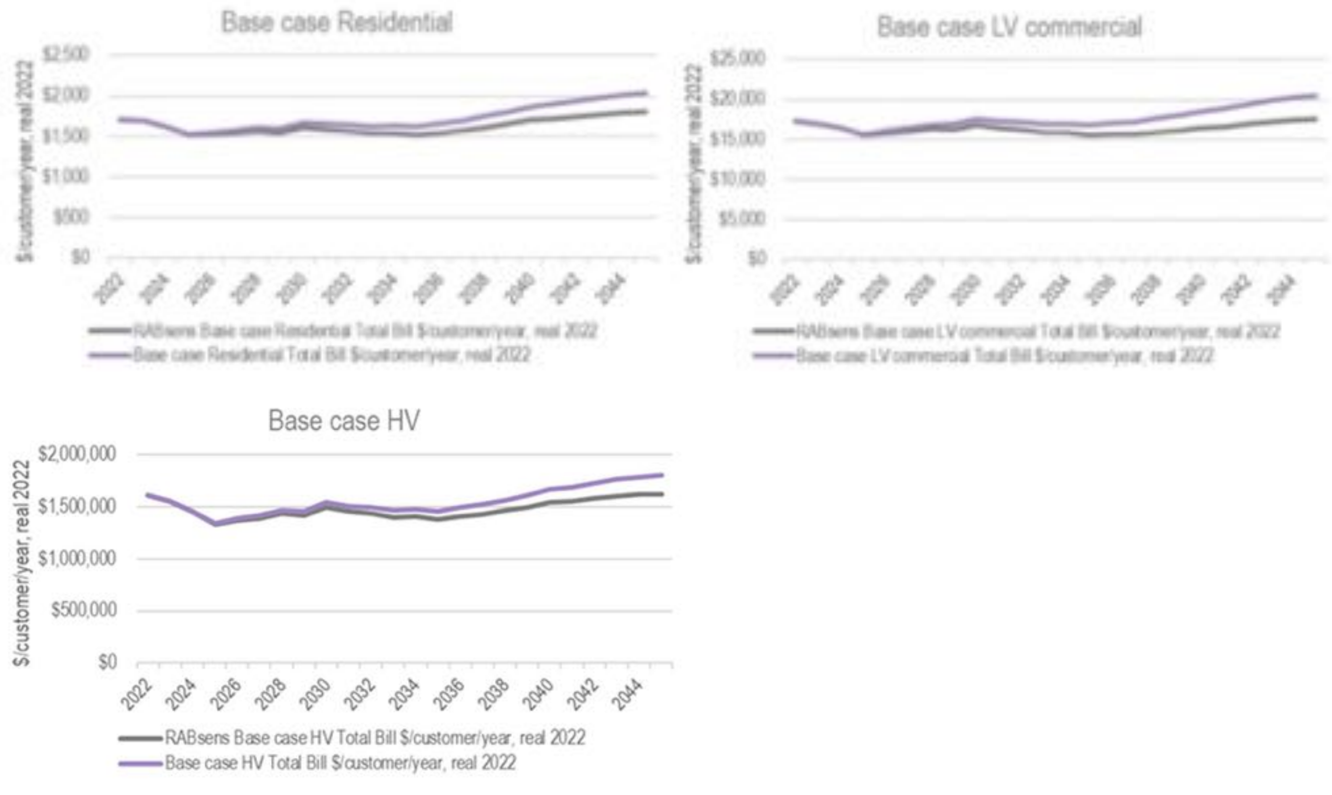
As discussed in the **Base case Report** we have adopted a conservative approach to setting RAB requirements (given the number of unknown factors that may impact final expenditure needs and timing).

Alternative optimistic RAB trajectories have been developed for the base case and each scenario, which result in significantly lower upgrade costs/expenditure as shown at Figure 43 (base case); Figure 74 (Scenario 1); Figure 112 (Scenario 2); and Figure 147 (Scenario 3) the respective RAB reductions by 2045 are 28 per cent for the base case; 34 per cent for Scenario 1; 33 per cent for Scenario 2; and 37 per cent for Scenario 3.

In the base case, a reduction in the RAB of 28 per cent by 2045 results in a reduction of the residential, LV commercial and HV retail bill by 11 per cent, 14 per cent and 10 per cent, respectively, by 2045 (see Figure 182).

The analysis shows that RAB requirement will have a material impact on retail bills under all scenarios from around 2030 onwards. While there is considerable uncertainty as to final RAB requirements it is expected that retail bill outcomes would fall between what are essentially the upper and lower bounds shown in the figures below.

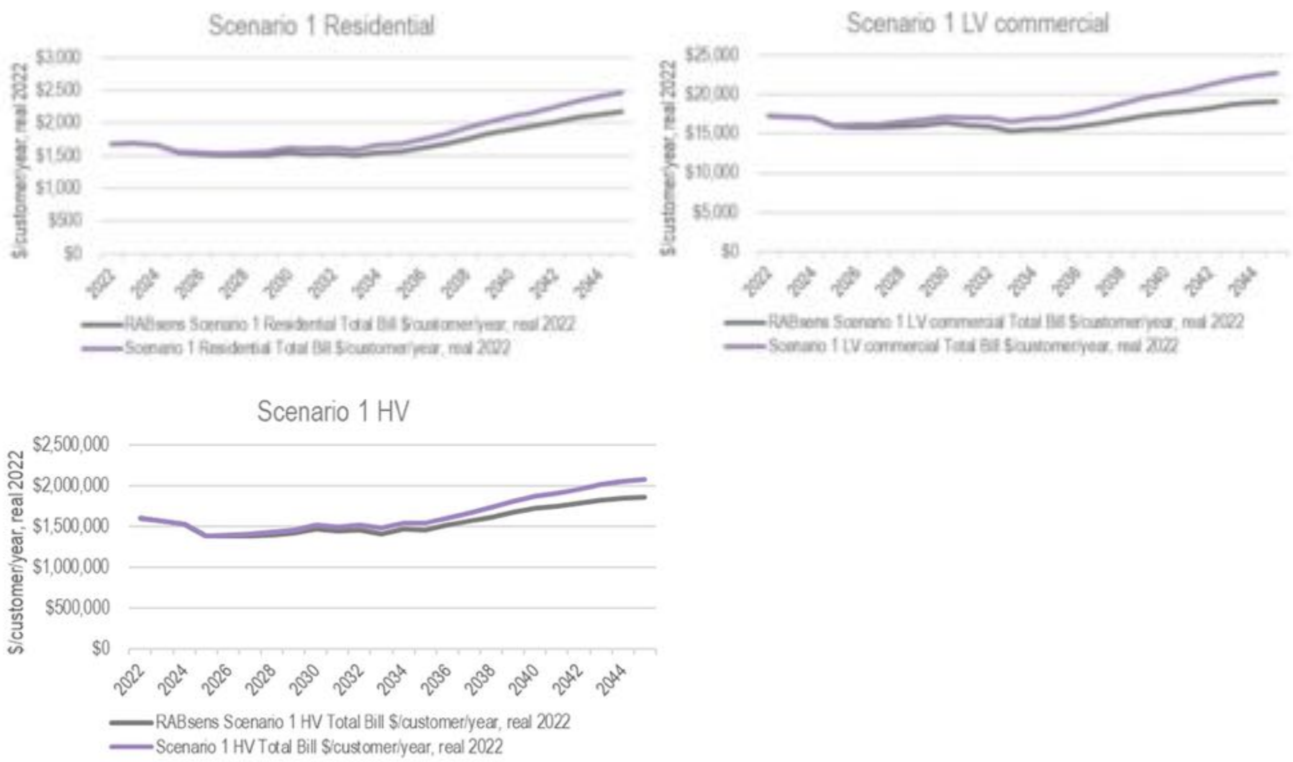
Figure 182 RAB sensitivity on base case – retail bill impact by customer



Source: ACIL Allen

For Scenario 1, a reduction in the RAB of 34 per cent by 2045 results in a reduction of the residential, LV commercial and HV retail bill by 11 per cent, 15 per cent and 11 per cent, respectively, by 2045 (see Figure 183).

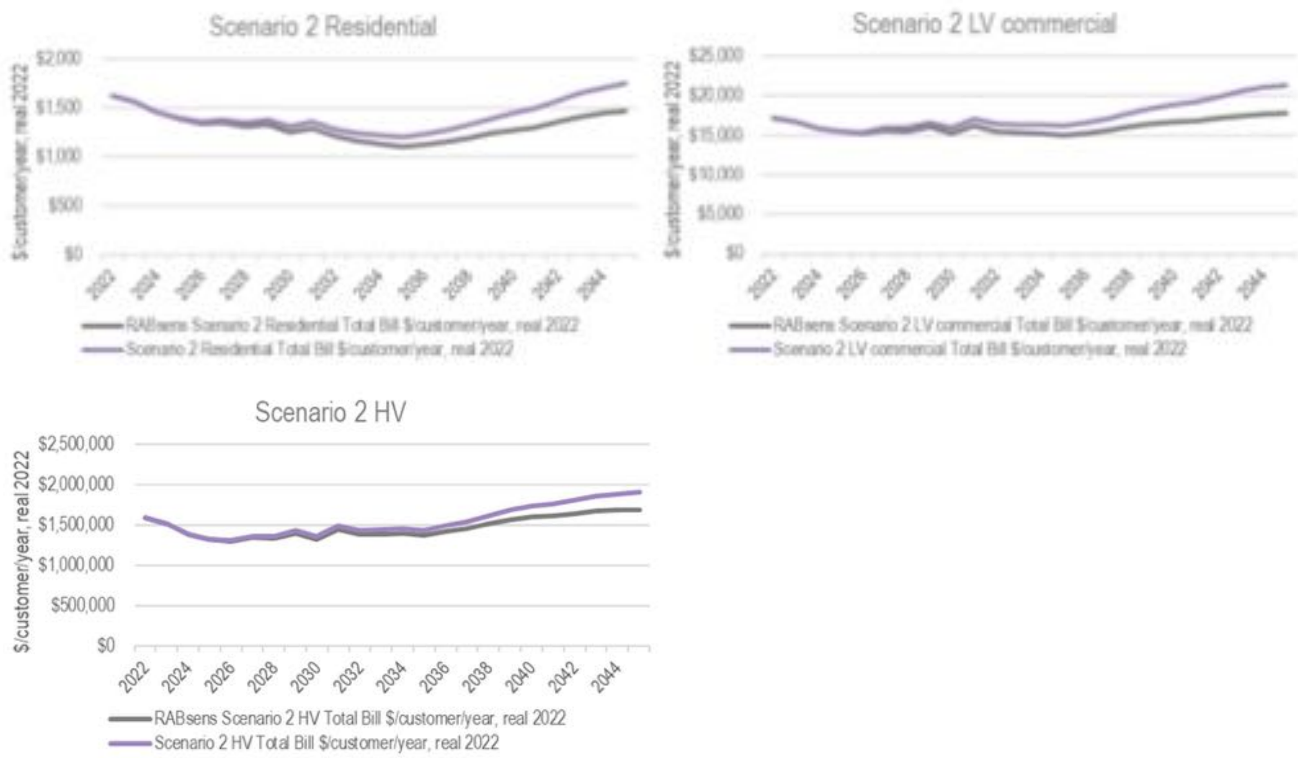
Figure 183 RAB sensitivity, Scenario 1 – retail bill impact by customer



Source: ACIL Allen

For Scenario 2, a reduction in the RAB of 33 per cent by 2045 results in a reduction of the residential, LV commercial and HV retail bill by 15 per cent, 17 per cent and 12 per cent, respectively, by 2045 (see Figure 184).

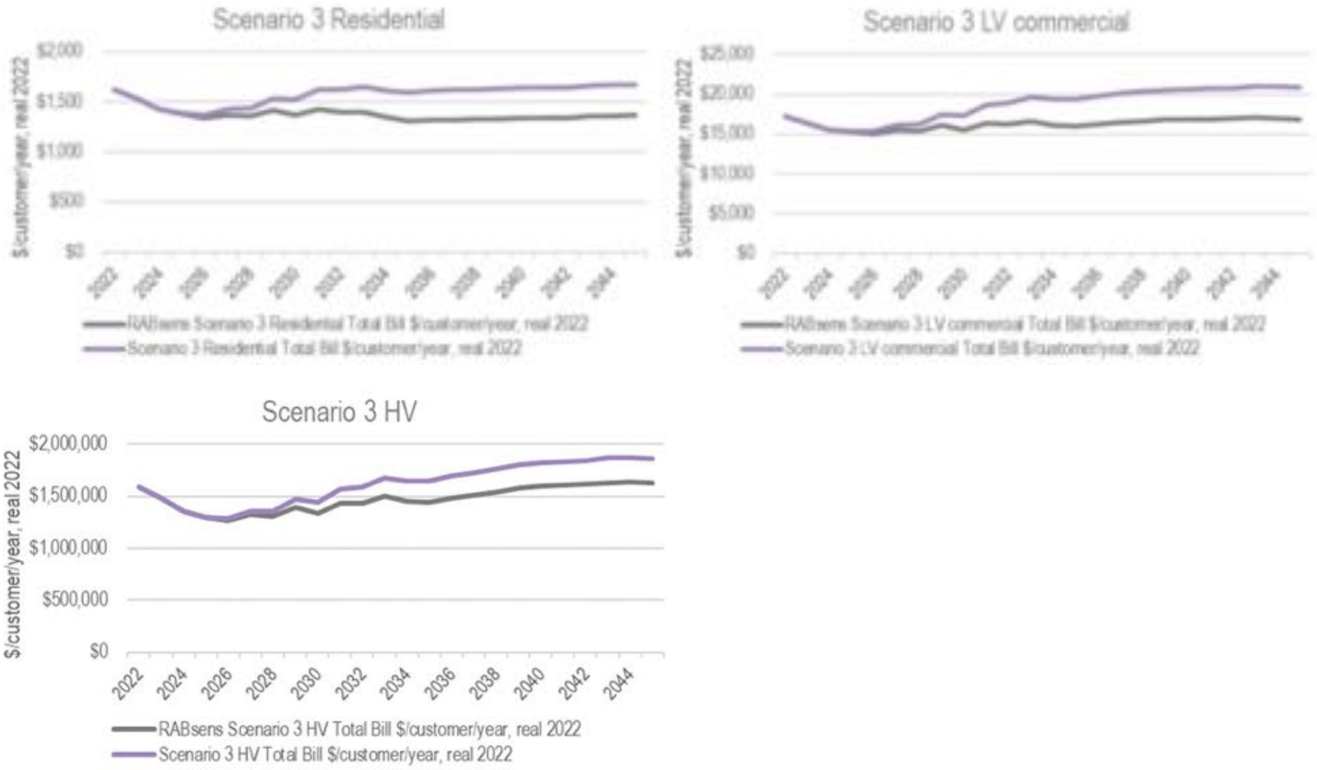
Figure 184 RAB sensitivity, Scenario 2 – retail bill impact by customer



Source: ACIL Allen

For Scenario 3, a reduction in the RAB of 37 per cent by 2045 results in a reduction of the residential, LV commercial and HV retail bill by 17 per cent, 20 per cent and 13 per cent, respectively, by 2045 (see Figure 185).

Figure 185 ***RAB sensitivity, Scenario 3 – retail bill impact by customer***



Source: ACIL Allen

9.4 Gas 'tipping point'

A significant question that is raised from an analysis like this is what might happen to the gas network over time as the level of gas consumption declines considerably. ACIL Allen has attempted to analyse where the 'tipping point' may occur for the Evoenergy network as gas consumers increasingly convert to electricity.

Two methodologies were considered for this analysis – to estimate:

- consumer savings from switching to electricity and determine at what point it is highly unlikely that gas consumers would continue to use gas
- when the network ceases to be economically viable from the point of view of distributor's revenue projections, and projections on costs, rates of return etc.

ACIL Allen has chosen the first method for this analysis and builds off work recently completed examining household switching (gas to electricity) in the ACT. Moreover, ACIL Allen is not privy to the detailed Evoenergy financial data (asset valuations, investment strategy, financing models etc) that would be required to undertake the analysis from the point of view of the distributor.

The results of this analysis show that many households already have an incentive to electrify, and over time consumer savings increase significantly if gas users switch to electricity. Eventually there becomes a point where it is difficult to envisage that gas consumers will not convert to electricity, unless physical (or legal) constraints prevent conversion. The analysis considers the increase in projected retail gas bills under the base case and the three scenarios and infers whether disconnections might happen more quickly than projected.

The work focuses on the time at which this point could occur in the future. Once prices reach a point where the consumer savings significantly favour switching from gas to electricity, a tipping point will occur. At this point, disconnections are likely to accelerate rapidly resulting in pressures on Evoenergy's revenue base. Increasing prices (if allowed by the regulator) to support the revenue base will exacerbate the problem leading to spiralling breakdown of the gas network.

9.4.1 Methodology

The methodology used for this analysis is built upon recent work undertaken by ACIL Allen for the ACT Government in 2020 on energy choices for ACT households. This work investigated what the consumer savings/impacts would be if different gas users switched from gas to electricity. It adopts the consumer's perspective in deciding whether or not to electrify in each year of the analysis – presented in net present value terms over a 15-year period. A conclusion is then made on whether the switch from gas to electricity for these households is financially beneficial.

Our analysis updates these previous findings and then examines how this might impact gas connections. The analysis presupposes that a decision to convert is purely on an economic rational basis. However, there will be a range of other personal considerations that come into play – preference for gas cooktops over electric, capital and installation cost and capacity to finance the conversion, age and residual life/value of existing appliances, building fabric and structural constraints and long-term renovation plans etc. While there are already economic signals pointing to the advantages of conversion, the fact this is not happening to a greater extent suggests there are large frictions which are difficult to observe and quantify directly.

While more complex methodologies could be adopted, given time and budget constraints, this analysis is considered appropriate to determine when the tipping points might occur. For a more specific and detailed assessment, sophisticated and dynamic modelling is required, coupled with a detailed understanding of the long-term objectives of the distributor, its financial and profit maximisation objectives, and the role of the gas network in its overall business portfolio. Decisions around shut down for a network are complex and beyond the scope of this analysis.

The analysis looks to determine at what point consumer savings become so substantial that they drive significant switching to electricity. ACIL Allen will then infer (a speculative view) at what point continuing operation of the Evoenergy gas network becomes doubtful. It shows the general period (e.g. the most likely what regulatory cycle, such as 2026-31 or 2036-41) during which it is likely that the consumer savings from switching from gas to electricity are large enough to bring into question the continuing economic viability of the network.

9.4.1.1 Household energy choice modelling

In simple terms, the objective of the methodology is to understand the relative costs to ACT householders in choosing between electricity and gas. Gas is a less versatile fuel in comparison to electricity, with substitution limited to the following three activities from a practical perspective:

- space heating
- water heating
- cooking.

The appliances used for these activities tend to be expensive, long-lived, and are usually fixed in place. For these reasons, the decision to use electricity or gas is one that is made when buying appliances, or even during property design and construction. This decision is broader than just the choice of the fuel itself. The cost involved in this choice includes the upfront cost of buying and installing the relevant appliance and the cost of any modifications that might be required to the home itself.

These 'choices' will vary depending on aspects of the household, and the householder, in question. For example, people living in apartments may not have control over the fuel used for water or space heating, given this may be centralised. In other cases, there may not be sufficient physical space to replace an instantaneous gas water heater with a much larger electric heat pump. Appliance choice also depends on how it will be used and individual householder preference (e.g. gas vs electric cooktops).

Options for the installation of solar PV may also have a bearing on household decisions. Some consumers may elect to install PV in conjunction with a gas to electric conversion, seeking to defray electricity costs, notwithstanding the initial capital outlay.

The analysis takes these differences into account by evaluating the changeover costs that would be faced by a group of 12 indicative households. The analysis can be thought of as a series of hypothetical case studies which are intended to resemble people living in the ACT and the choices they face. However, they are not necessarily representative of all of the households in Canberra or the relative number of households of each type.

To ensure a focus on the difference between the cost of using gas and the cost of using electricity, the analysis rests on two 'cases':

- a counterfactual case, in which the household in question is assumed to continue using gas
- a policy case, in which the household in question is assumed to switch from gas to electricity (including some that concurrently install solar PV).

The analysis focuses on the cost that households would incur if policy settings were in place such that households choose to switch. Therefore, we do not consider the extent to which households would choose to switch, rather we assume that they have chosen to switch and examine the difference in cost. The results show the estimated savings households obtain from switching to electricity from converting to electric water heating, cooking and space heating, accounting for connection/disconnection costs and the cost of appliances and installation.

9.4.2 Assumptions

The assumptions used in this analysis are generally in line with those in in ACIL Allen's previous work for the ACT Government (referred to above).[41] Key assumptions for this analysis include:

- type of house (e.g. unit, townhouse, house)
- size of household (one person, two-person etc)
- appliance costs and installation costs
- energy use profiles for the different household types
- electricity and gas prices.

Besides updating electricity and gas price inputs, the other assumptions remained the same (given the original work was completed just over a year ago).

9.4.2.1 Electricity and gas prices

The analysis is based on updated electricity and gas price projections that have been incorporated in the base case and used throughout this project. These prices were fed into the household energy saving model. A summary of projected gas and electricity prices under the base case and each of the three scenarios modelled is presented in the report at Figure 168 and Figure 177 respectively.

[41] ACIL Allen: Household Energy Choice in the Act - Modelling and Analysis, November 2020

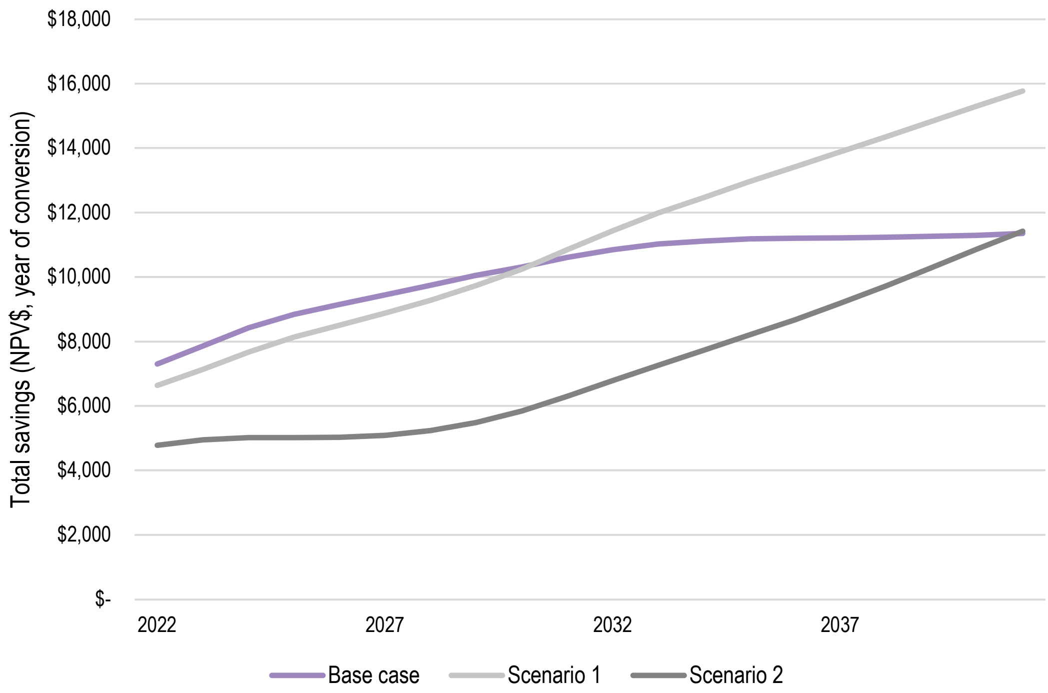
9.4.3 Modelling outcomes

The modelling outcomes for the different scenarios are represented in Figure 186 below. The figure shows that as gas prices increase for the base case and Scenarios 1 and 2, the potential cost savings from converting in any particular year increase out to 2041 (modelled over a 20-year period). (Scenario 3 is not presented, given that the retail price analysis for the scenario clearly indicates that the viability of the network is challenged from around 2030.)

For example, the average residential user's total savings from converting to electricity in 2025 in the base case is around $9,000 – that is, the household is facing a $9,000 decision in that year (to be realised over the following 15 years) if they have not already electrified. However, in Scenario 2, the saving is less at around $5,000. This is due to electricity prices in Scenario 2 increasing at a faster rate, as well as being higher over the entire modelled period. Therefore, the gas consumer in Scenario 2 saves less from switching because electricity prices are also increasing on a per unit basis more than in the base case or Scenario 1.

However, this analysis does not incorporate the estimated decline in average consumption per customer as presented in earlier chapters. This analysis is focused on the cost savings from moving to electricity from gas and consuming the same amount of energy, on a per unit basis. A larger disparity between gas prices and electricity prices (on a per unit basis) is observed in the base case and Scenario 1, while under Scenario 2 the difference is less. This leads to a smaller cost saving in Scenario 2.

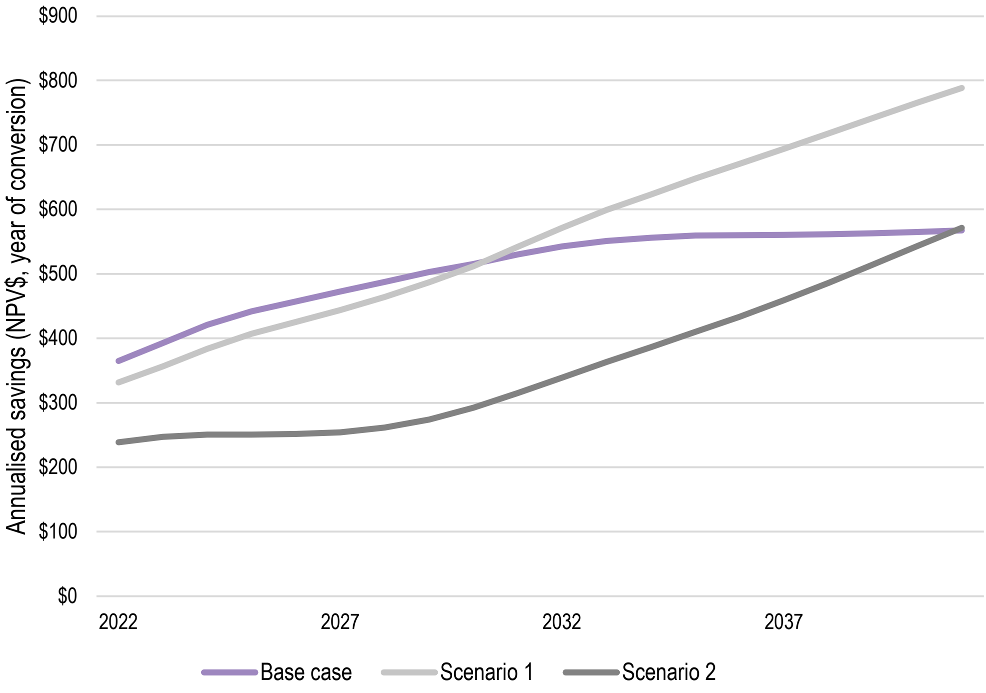
Figure 186 Residential consumer saving from switching to electricity, total savings (NPV$)



Source: ACIL Allen

Figure 187 shows these results on an annualised basis. This demonstrates the savings on an annual basis if customers switched in a particular year. What this clearly demonstrates is that at current gas and electricity prices, gas users would be better off financially by converting to electricity as soon as possible. The savings on an annualised basis for the period suggest gas users would be saving around $350-380 per year in the base case and Scenario 1 from 2022, rising to levels around $600 by 2040 in the base case and over $800 in Scenario 1.

Figure 187 Average residential consumer saving (NPV$, annualised basis)



Source: ACIL Allen

In Scenario 2, the cost savings on an annualised basis are much lower in comparison, but still indicate that a move to electricity is financially beneficial. However, in this scenario the decision to move to electricity is not as clear cut.

9.4.4 Sensitivities

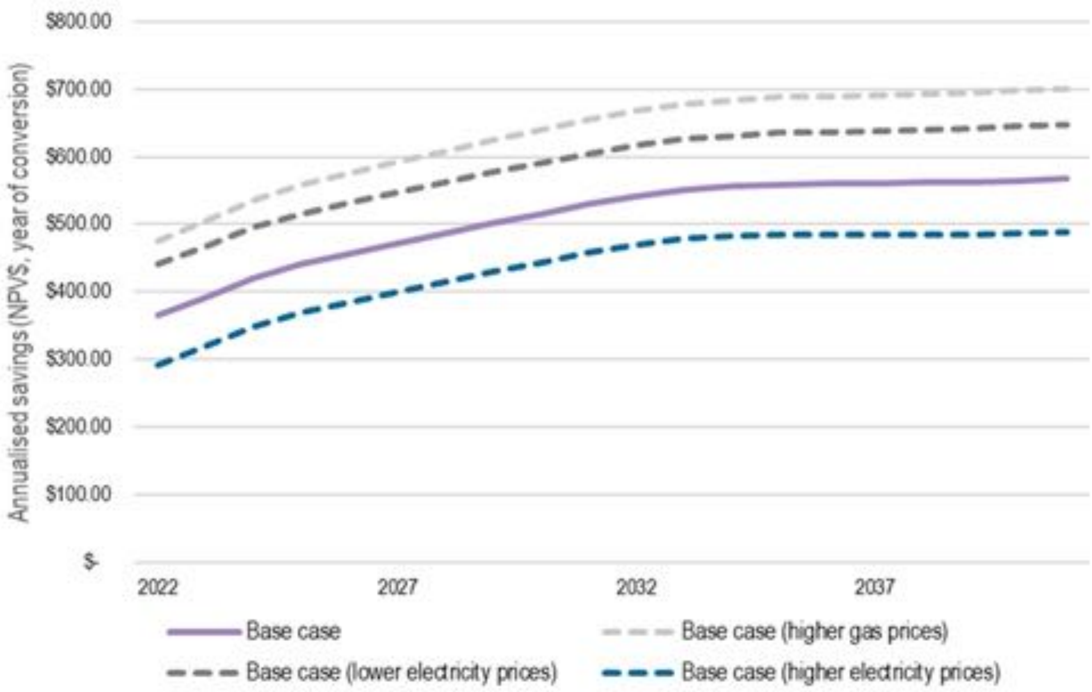
9.4.4.1 Price sensitivities

Were projected gas prices higher or electricity prices lower, this would impact the results of the analysis. For the purposes of the report, we have used conservative gas price assumptions. Therefore, our analysis is likely to under estimate the possible consumer conversion savings. Accordingly, we have tested the sensitivity of the analysis assuming gas prices were 10 per cent higher. The outcome from higher gas prices and lower electricity prices for the base case is shown in Figure 188.

The annual cost saving is around $125 per year more if gas prices did rise by 10 per cent. The results for Scenarios 1 and 2 are similar, with the additional saving varying between $80 and $100 per annum (not shown). These outcomes add further weight to the argument that the incentive to switch from gas to electricity is likely to occur earlier in the projection period.

Alternatively, a similar outcome would occur if electricity prices were 10 per cent lower. In addition to showing higher gas prices and lower electricity prices, we have also tested the impact from 10 per cent higher electricity prices. The estimated savings from switching are lower than in the base case in this case. However, a key finding is that the impact on estimated savings is larger when gas prices move, compared with a change in electricity prices of the same magnitude.

Figure 188 Average residential consumer saving, base case, higher gas price and higher/lower electricity prices (NPV$, annualised basis)

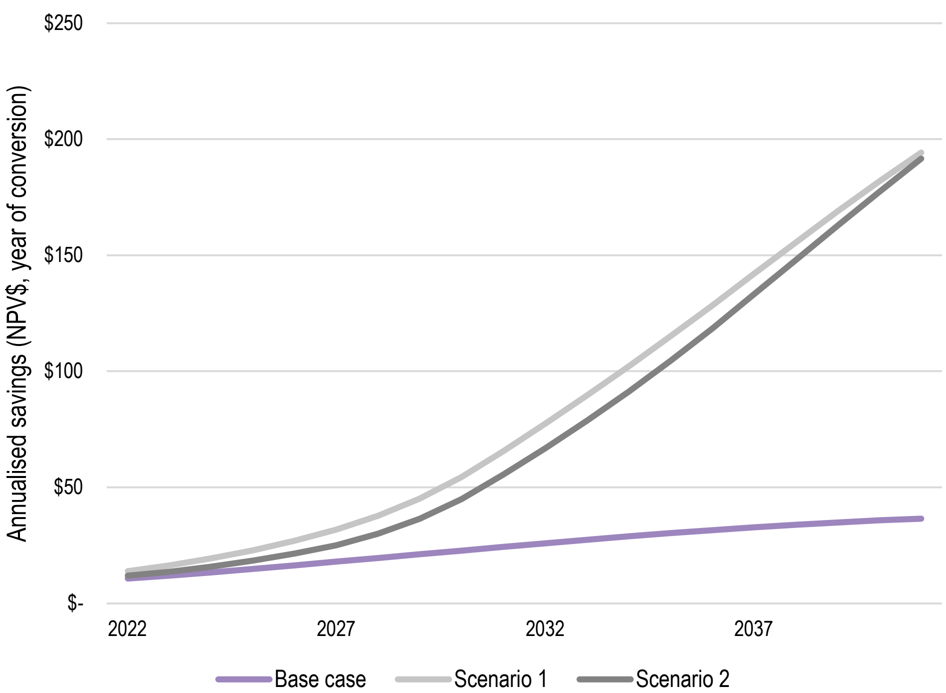


Source: ACIL Allen

9.4.4.2 Impact of rising fixed connection costs

Rising fixed connection costs have a significant impact on overall cost savings (savings projections include changes in fixed connection costs). Over time, as the number of gas connections fall, the fixed network costs are spread over a smaller number of customers. Accordingly, higher fixed costs increase the potential cost saving from switching from gas to electricity. Figure 189 shows the impact rising fixed connection costs have on the overall cost saving.

Figure 189 Average residential consumer saving from fixed connection costs (NPV$, annualised basis)



Source: ACIL Allen

It shows that under the base case the fixed network cost contributes a much smaller amount of the cost savings as disconnections trend lower at a slower rate. However, the situation is different for Scenarios 1 and 2 which see larger reductions in the number of gas connections. As this occurs under these scenarios, higher fixed connection costs result.

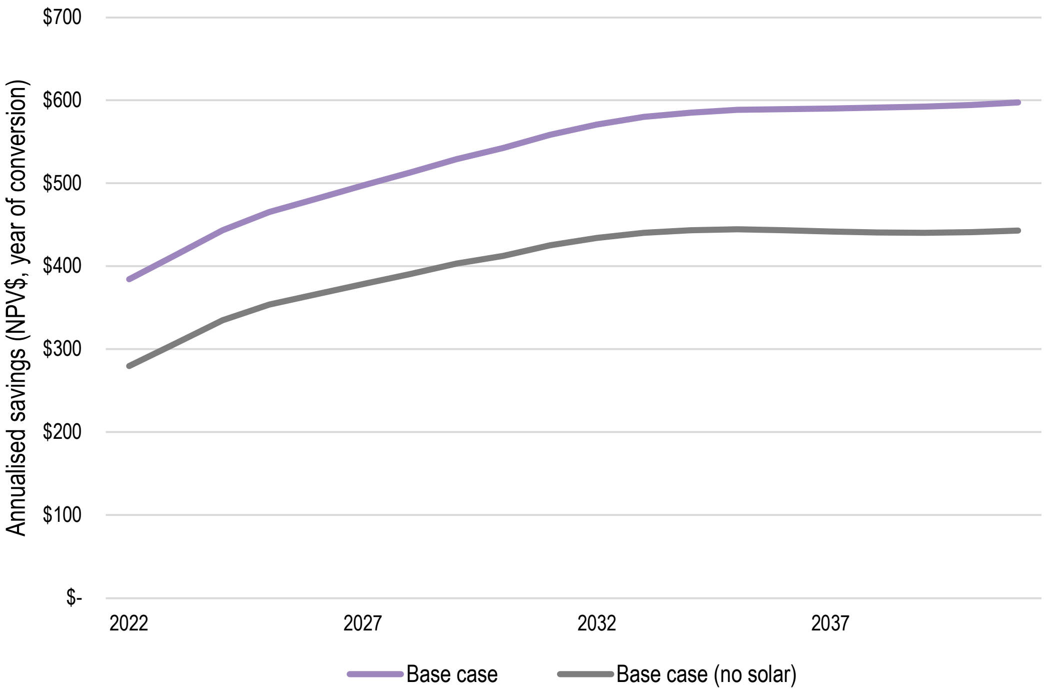
Post 2030, the cost savings increase in Scenario 1 and 2, given higher disconnection rates as customers choose to switch to electricity to avoid higher fixed connection fees (required to recover network costs from a small customer base).

9.4.4.3 Solar PV vs non-solar PV

A further key sensitivity is that the results represent the average of two alternatives that could apply as gas consumers switch to electricity. In one case the consumer switch occurs concurrent with solar PV installation, in the other, the addition of solar PV is excluded.

Figure 190 presents the results of cost savings to gas users switching to electricity both with, and without, solar PV for the base case. This clearly shows the added value in terms of possible cost savings from switching from gas to a premises with electricity appliances when solar PV is also installed at the same time (PV capital and installation costs are incorporated into the modelling).

Figure 190 Average residential consumer saving, solar vs average, for the base case (NPV$, annualised basis)



Source: ACIL Allen

9.4.4.4 Difference in dwelling type

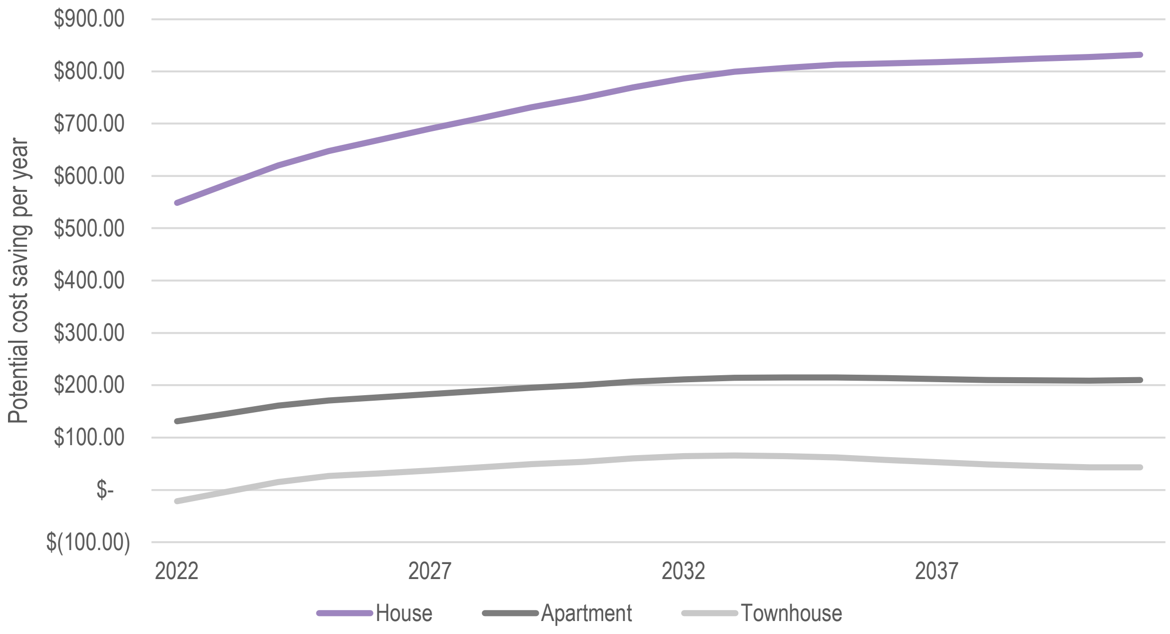
The analysis concludes that cost savings are estimated to be higher for houses in comparison to townhouses/units. Space heating accounts for the largest source of energy in standalone houses. For multi-unit dwellings, the cost saving is less, given smaller premises do not realise the same efficiency gains (from heating a smaller space with electrical heating rather than gas heating). They also typically have fewer options to switch, for example, not having space for a hot water heat pump which requires a large water tank, and typically have less access to rooftop solar PV.

For units and townhouses, the cost savings over time are much lower on an annualised basis. As shown at Figure 191, while the incentive for standalone houses to switch is clear in many cases, the incentive is much lower for townhouses and apartments.

This is an important factor that may have bearing on the overall continued viability of the gas network and delay the tipping point, given the recent trend in growth in new connections has been from smaller housing, such as townhouses and apartments. From 2006 to 2016, the share of the total housing stock which were standalone houses was 75 per cent. However, the proportion for standalone houses in 2016 had fallen to 67 per cent.[42] Over the period from 2006 to 2016, more than 16,000 multi-unit dwellings were built, compared to around 3,500 standalone houses.

This trend is likely to become more pronounced going forward (in line with forecasts in *ACT Planning strategy - Diverse Canberra*). The impact on the gas network will depend on the Government's evolving policy in relation to future gas connections for infill and urban redevelopment projects.

Figure 191 Average residential consumer saving, by household type, base case (NPV$, annualised basis)



Source: ACIL Allen

9.4.5 The tipping points

The analysis clearly shows potential cost savings only get higher over time. The question is then at what point does it become self-evident that that gas consumers would be very unlikely to continue to use gas (unless 'locked in' by other factors). Given the scenario analysis in earlier chapters does not consider the impacts from higher retail gas prices, there is a strong potential for the rate of disconnection to accelerate to higher levels than those projected in each scenario.

The five-year regulatory cycles for the Evoenergy network are the logical timeframes in which to consider these outcomes. The current regulatory period finishes in the 2025-26 financial year. The next period will commence from 2026-27 and run through to 2030-31. Our approach is to look to identify the regulatory period during which the tipping point is most likely to occur. While the analysis does not lead to a re-adjustment of the projections on gas connections

[42] Australian Bureau of Statistics: 2016 Census Quick Stats data for Canberra

and consumption, it is possible to make inferences as to the period Evoenergy could face increasing disconnection rates and inadequate revenues to support the continued operation of the network.

9.4.5.1 Base case and Scenario 1

Under the price projections estimated in the report, it is clear that, even in 2022, there is an economic case to switch from gas to electricity under the base case and Scenario 1. This is most evident for standalone households where the cost savings from more efficient electrical heating appliances potentially outweigh gas heating. For other dwelling types, the incentive is less significant.

By the early-mid 2030s the potential cost savings are much higher across all dwelling types. In annualised terms, gas consumers would be hundreds of dollars worse off each year under the base case and Scenario 1. This is largely on the back of retail prices escalating by more than 30 per cent (compared to 2022 levels). By the early to mid-2030s, it is likely that Evoenergy will face pressures to pass on higher fixed connection costs (particularly undern Scenario 1) and variable charges in the order to recoup costs. At this point, remaining gas consumers are likely to find themselves significantly worse off if they stay connected, and accordingly they can be expected to convert to electricity as soon as possible.

Based on the analysis, it is likely that a significant number of additional disconnections (in comparison to the base case) would be likely by the beginning of the 2037-41 regulatory cycle (possibly earlier in Scenario 1 - during the 2031-36 cycle). For example, by the early 2030s, the network could have around 12,000 to 15,000 less gas connections. By 2037, this could rise to 30,000 fewer connections. Given the financial savings that could be achieved from switching to electricity, the disconnection rates could be significantly higher, placing the viability of the network under more pressure earlier in the regulatory cycles.

9.4.5.2 Scenario 2

The case for switching under Scenario 2 is less clear. The potential cost savings from switching for the average household are smaller, albeit still positive. When assessed by dwelling type, the incentive to switch for apartments and townhouses is far less likely than standalone households.

The key reason for this is that under Scenario 2 the cost of electricity on a per unit basis is increasing at a faster rate than in comparison to the base case and Scenario 1. This limits the potential cost savings for gas users switching to electricity. In this case, it may not be until late in the 2030s that gas users would be far worse off (under all dwelling types) and switch to electricity.

Taking account of other results from this study, particularly the lower average electricity consumption per household, may further reduce the pressure to convert. If the projected difference in prices on a per unit basis are considered, this may push the potential tipping point to later in the modelling period, for example closer to 2040.

9.4.5.3 Scenario 3

Scenario 3 was not included in this analysis, given the gas price projections paint a very clear picture. In this scenario with such drastic reductions in connections from as soon as 2027, Evoenergy will be under significant pressure to pass on much higher costs to cover its operational costs. Large write-downs of the network would be likely to enable continuing supply gas to a rapidly declining customer base at affordable prices.

If not, it is likely the distribution network could be unviable as early as the late 2020s and the supply of much smaller volume of customers in the years post 2030 would be better serviced by tank gas.

9.4.6 Conclusion

The analysis demonstrates that the cost savings to gas users switching to electricity only increase over time. Those cost savings are already significant for standalone households under all cases as they could potentially reap financial benefits of more efficient and cost-effective space heating. In other dwelling types, this is not as significant. However, the cost savings are significant for all scenarios post 2030.

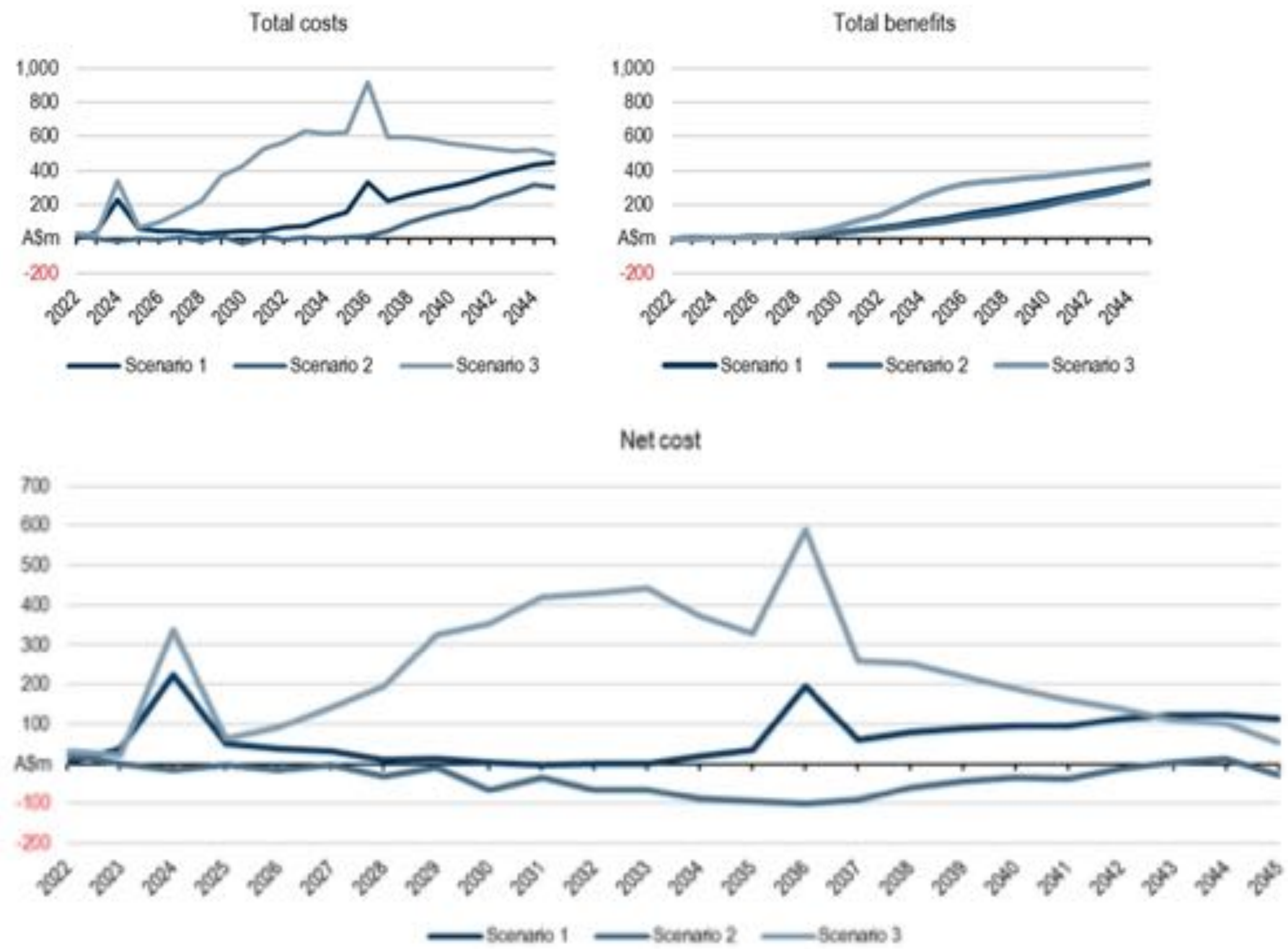
Rising fixed connection costs also contribute significantly to the potential cost savings that can be accrued over time. In Scenarios 1 and 2, this cost increases exponentially with higher rates of gas disconnections projected to occur. In Scenario 3 it is very clear what pressure the gas network would be under.

Cost savings under all scenarios are only set to rise and become stronger. By the 2030s, and particularly by the mid-2030s, cost savings are substantial and it is likely that disconnections will start increasing at a much higher rate than is projected. Therefore, the ACT distribution network and its assets could be unviable earlier than 2040, particularly in the case of extreme cuts in gas consumption such as under Scenario 3.

9.5 Economic impact - costs and benefits

The transition of the ACT energy system under the alternative decarbonisation scenarios will come with a range of costs and benefits compared to the base case. Broadly, there will be a range of additional expenses related to increasing renewable electricity usage, but these will be offset by reductions in gas, petrol and diesel usage and their associated costs. In addition, there will be extra reduction in GHG emissions under the alternative decarbonisation scenarios compared to the base case. Figure 192 presents the annual total costs, total benefits and net cost for each scenario, relative to the base case, while Table 21 presents a summary of the various direct costs and benefits of each scenario compared to the base case.

Figure 192 Total costs, benefits and net cost of each scenario, relative to the base case



Note: The cost 'spike' in 2024 relates to the additional large and community battery installation costs (the 2036 'spike' corresponds to the refresh of these batteries)
Source: ACIL Allen

9.5.1 Costs

In total, the additional costs relative to the base case, related to the shift toward electrification (including electricity related network, distribution, generation, storage, vehicle, appliances, and changes in retail prices) are projected to be:

- +$1,606 million under Scenario 1
- +$497 million under Scenario 2
- +$4,380 million under Scenario 3.

Scenario 3 is expected to have the largest additional costs relative to the base case, driven by the need to undertake significant capital expenditure on upgrading the electricity network.

Notwithstanding the additional generation of electricity behind the meter using rooftop PV, consumers in Scenario 1 are projected to be buying an additional $192 million of electricity from the grid relative to the base case (in NPV7 terms), while the total value of electricity purchased from the grid, relative to the base case, falls in Scenarios 2 and 3 (by $815 and $707 million, respectively).

At $405 million, the additional cost of ZEVs is the same in all scenarios relative to the base case (given the base case uses the Deloitte 'conservative' projections, while all of the scenarios use the 'optimistic' projections).

9.5.2 Benefits

In total, the additional benefits relative to the base case, related to the shift away from gas and ICE vehicles (including gas related network and distribution costs, gas and vehicle fuel costs, and changes in human health costs associated with reduced noxious emissions from vehicles) are projected to be:

- +$906 million under Scenario 1
- +$842 million under Scenario 2
- +$1,601 million under Scenario 3.

Scenario 3 is expected to have the largest additional benefits relative to the base case, driven by the largest savings in gas purchases by consumers.

At $708 million and $80 million, the savings in vehicle fuel purchases and human health costs associated with the switching from ICE vehicles to ZEVs respectively, are the same in all scenarios (given the base case uses the Deloitte 'conservative' projections, while all of the scenarios use the 'optimistic' projections).

9.5.3 Net cost and GHG emissions

The net change in the direct costs and GHG emissions compared to the base case is projected to be:

- +$700 million under Scenario 1, with a cumulative reduction of 2.3 Mt CO_2-e
- –$344 million under Scenario 2, with a cumulative reduction of 2.1 Mt CO_2-e
- +$2,779 million under Scenario 3, with a cumulative reduction of 5.0 Mt CO_2-e.

While Scenario 3 is projected to have the largest reduction in GHG emissions compared to the base case (driven primarily by the rapidity with which gas is removed from the ACT energy system), it is also the scenario with the highest additional net costs (driven by the large capital expenses needed to boost electricity supply earlier in the projection period and to ensure security of supply).

The net cost of Scenario 2 relative to the base case is negative, meaning that the overall reduction of gas and other fuel costs (and human health benefits) are greater than the increased costs associated with the additional electricity-related expenses.

However, these costs do not include any allowances for the cost of achieving the various additional energy efficiency measures assumed to take place in the scenarios relative to the base case (while the benefits in terms of reduced energy requirements are included). Without including this cost item, it is not possible to make a definitive assessment of the relative merits of the base case projection nor of the various scenarios.

9.5.4 Implied emissions abatement cost

Notwithstanding the caveat regarding the missing costing of energy efficiency improvements relative to the base case, it is possible to estimate the implied marginal emissions abatement cost of the additional emissions reduction in each scenario. The implied a GHG emission abatement cost associated with each of the scenarios is:

- +$301/t CO_2-e under Scenario 1
- -$166/t CO_2-e under Scenario 2
- +$554/t CO_2-e under Scenario 3.

Table 21 Costs and benefits of each scenario, relative to the base case

		Scenario 1 (NPV7)	Scenario 2 (NPV7)	Scenario 3 (NPV7)
	Description	**real A$m**	**real A$m**	**real A$m**
	COSTS			
	Additional CAPEX (relative to the base case)			
1	Electricity network and distribution	433.5	134.5	3,261.6
2	Grid connected batteries	273.1	263.7	669.4
3	Behind the meter PV and batteries	301.0	507.9	745.8
4	ZEVs cost premium	404.6	404.6	404.6
5	Appliances (net)	1.8	1.4	5.7
6	Net additional retail electricity cost	191.9	-814.8	-707.1
7	Energy efficiency capital expenses	*Not costed*	*Not costed*	*Not costed*
A	**Total change in costs [=1+2+3+4+5+6+7]**	**1,605.9**	**497.3**	**4,380.2**
	BENEFITS			
8	Reduced gas network and distribution CAPEX	3.5	1.9	24.3
9	Net reduction in retail gas cost	114.8	52.1	789.3
10	Reduced vehicle retail fuel cost	707.6	707.6	707.6
11	Reduced vehicle human health costs	80.1	80.1	80.1
B	**Total benefits (excl. GHG) [=8+9+10+11]**	**905.9**	**841.6**	**1,601.2**
C	**Net change in costs (relative to the base case) [=A-B]**	**699.9**	**-344.3**	**2,778.9**
	REDUCTION IN GHG EMISSIONS	kt CO_2-e	kt CO_2-e	kt CO_2-e
12	Reduced vehicle fuel use	1,689.5	1,689.5	1,689.5
13	Reduced gas use	635.0	387.7	3,322.5
14	Changes in electricity consumption	0	0	0
D	**Total reduction in GHG emissions [=12+13+14]**	**2,324.6**	**2,077.3**	**5,012.0**
		\$/t CO_2-e	**\$/t CO_2-e**	**\$/t CO_2-e**
E	**Implied abatement cost [=C/(D/1000)]**	**301.1**	**-165.8**	**554.5**

Note: All dollars are in real 2022 terms. Pricing for (6) Net electricity costs, excludes the pass through of capital expenditure (1) to customers. The additional cost of (2) Grid connected batteries, includes additional annual fixed operating and maintenance costs. There is no change in emissions from electricity given the policy of purchasing 100% renewable electricity.

Source: ACIL Allen

9.6 ACT economy-wide impacts

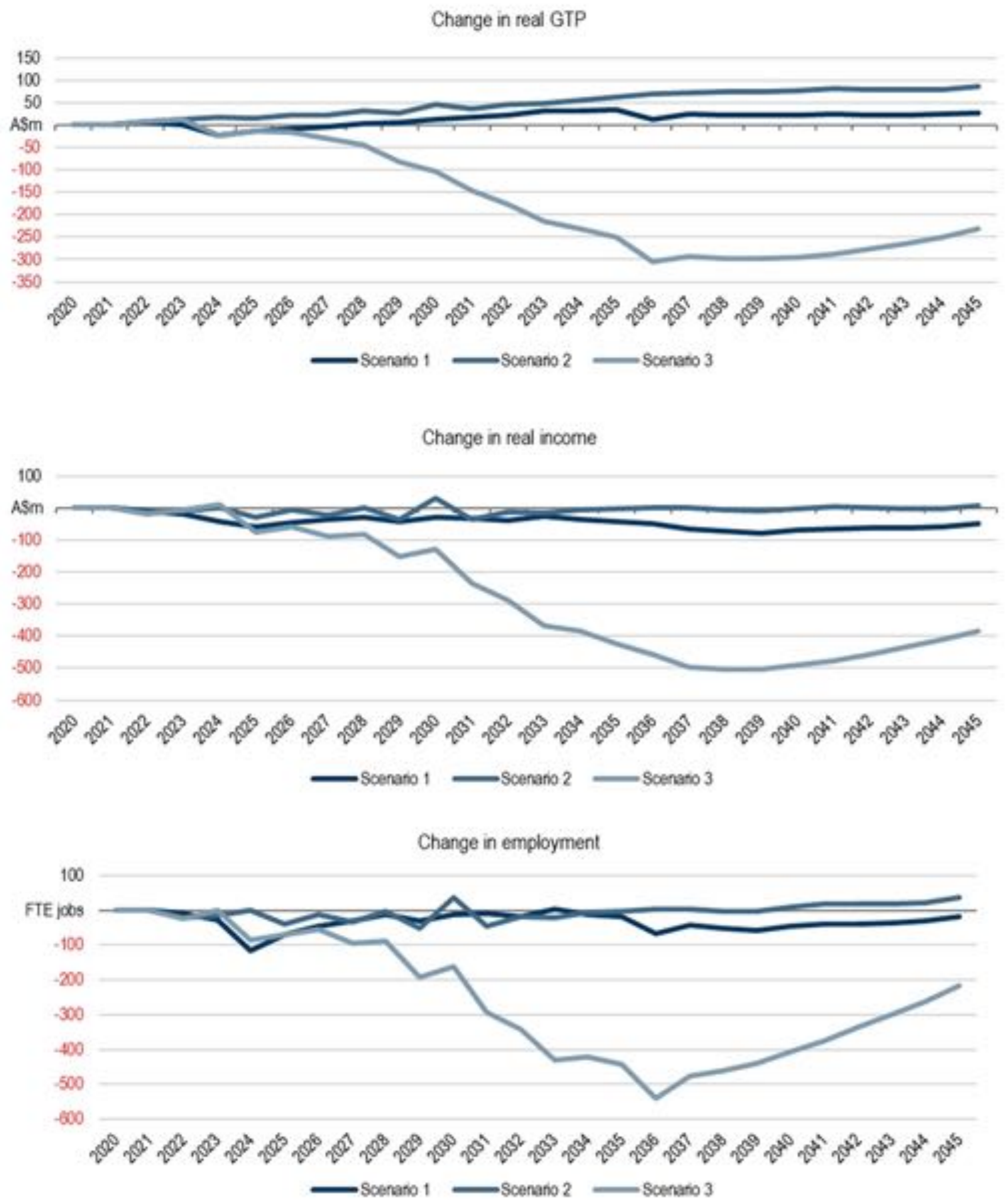
Figure 193 shows the annual macroeconomic and employment impacts of each scenario, relative to the base case. There are significant changes in the projected impacts through time. This is driven by the relative timing of different major drivers of the impacts including the timing and size of changes in investment, electricity prices and volumes, gas prices and volumes, and vehicle fuel purchases.

From a macroeconomic perspective Scenario 2 clearly delivers the best outcome in terms of GTP, real income and employment. It is also the most economically stable scenario with the smallest year on year fluctuations.

As discussed earlier, the best macroeconomic indicator of the change in the welfare of ACT residents is the change in real income. In total, over the period to 2045 the cumulative change in the real income of ACT residents, relative to the base case, (using NPV7) is:

- -$474 million under Scenario 1
- +$102 million under Scenario 2
- -$2,397 million under Scenario 3.

Figure 193 Macroeconomic impacts of each scenario, relative to the base case



Source: ACIL Allen

10. Net zero implementation pathway

The scenarios discussed in this report highlight a range of pathways the ACT Government could adopt to decarbonise the economy and contribute to the 2045 net zero target. While there are significant costs in reaching this goal, net zero will also bring significant benefits and opportunities, such as economic growth and jobs in new green sectors, reducing air pollution with benefits for health, and enhancing biodiversity.

Other considerations that will impact on achieving net zero emissions by 2045 are set out within this Chapter.

10.1 A strengthened systems approach to delivery

The integration and alignment of decisions and investments across Government, including policies, programs, regulatory design, infrastructure planning and expenditure activities that will have an impact on emissions is critical for attainment of a net zero transformation.

The ACT Government's current approach reflects a systems approach in that it premises action in dynamic policy making that considers the net costs and benefits to the environment, society, and economy as parts of an interconnected system.

Continuance and strengthening of this approach will help to ensure the design of policy is intrinsically linked to the net zero commitments of the ACT Government, whilst supporting the maximisation of benefits including maintaining a holistic view across the economy. Better integration across Government will further support the development and enhancement of new and existing initiatives to support business and the community as they adopt low emission technologies and practices.

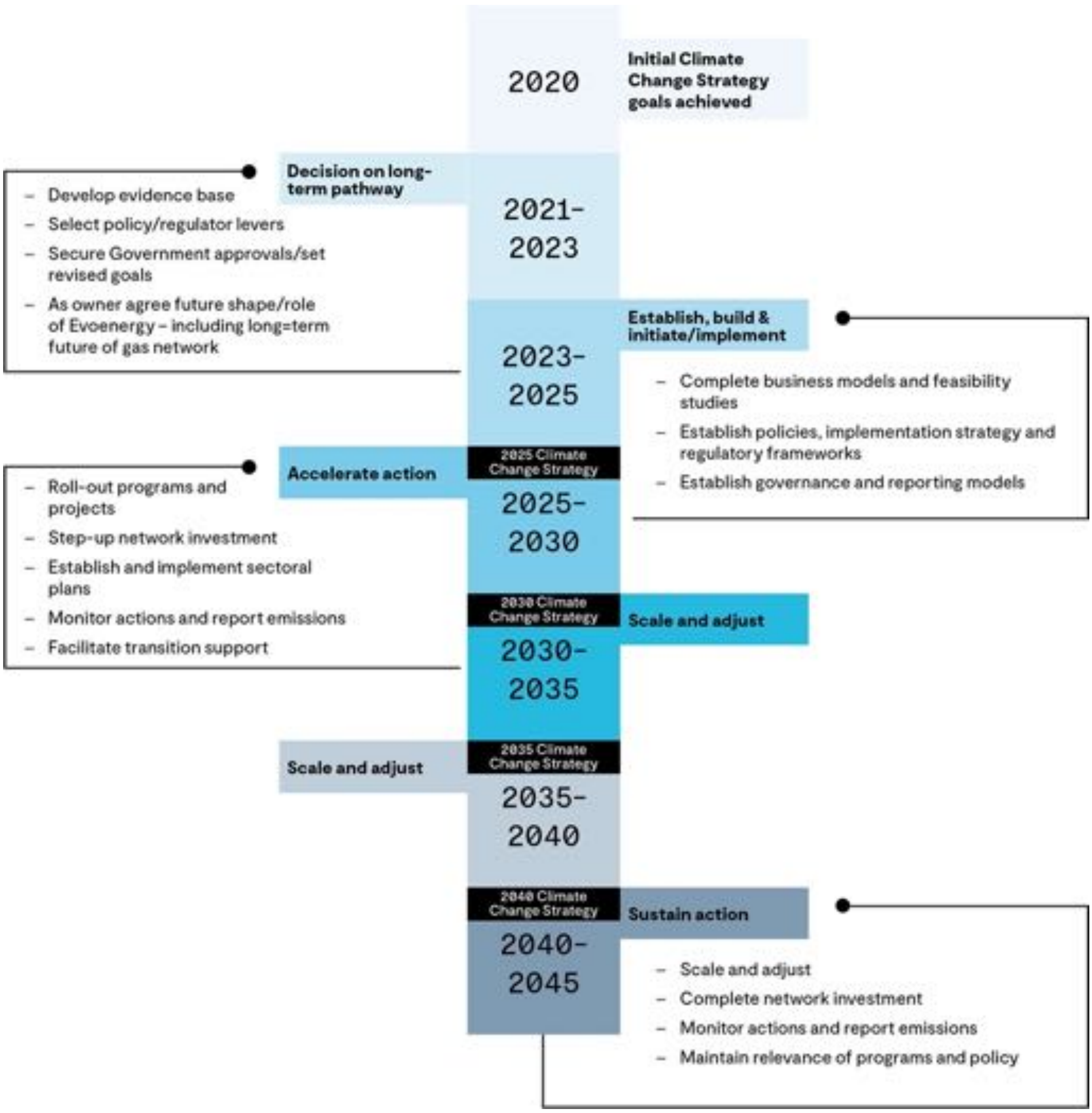
10.1.1 Sectoral roadmaps

Progress towards net zero will require the development and implementation of integrated sectoral plans that support economy wide emission reduction action. Sectoral roadmaps will importantly allow for the tracking of tangible emission reduction actions to confirm if the ACT Government is on-track to achieve net zero by 2045. The roadmaps selected will need to align to the scenario pathway selected by the ACT Government and should take a 5-year forward vision allowing for adjustment and amendment to reflect real-time emission reduction achievement. Periodic reviews of the scenario and roadmap (at least every five years) will support readjustments based on changing circumstances, as well as evidence progress towards the overall 2045 net zero target.

10.2 Early action to support transformation

Achieving this transformation will require early action/'wins' and a sustained focus on implementing policy and supporting investment programs to reduce GHG emissions and supporting resilient and sustainable communities. Detailed timelines with supporting GHG emissions targets will be required following down-selection of the net zero pathway selected by the ACT Government. Figure 194 highlights the indicative phases of planning and delivery required to meet the 2045 net zero timeline.

Figure 194 Indicative phases of planning and delivery required to meet 2045 net zero timeline



10.3 Policy considerations

10.3.1 New and enhanced frameworks

To achieve its ambitious 2045 net zero target, implementation of frameworks that sufficiently prioritise net zero emissions across Government will be required to support better policy development and the implementation of change in support of the 2045 vision. Frameworks and supporting policy need to be aligned to the scenario transition pathway adopted by the ACT Government. This will require new and/or modified policy and regulatory frameworks and funding. Any gaps in mechanisms that will support the selected transition pathway will need to be designed and considered in future budget years. This consideration will need to occur early to allow for maximum opportunity to capitalise on any additional emission reduction strategies and activities necessary to meet the 2045 net zero target.

10.3.2 Public discourse

The ACT Government, in addition to its policy and activities, will need to implement a supporting communications program that provides information setting out benefits and challenges of transitioning to a net zero emissions economy and what will be required at an individual (household) level. This means more awareness raising of the 'what, why and when'.

Support for low carbon and environmental practices will require people and businesses to make green choices. Government has a role to play in making these decisions as easy, attractive, and accessible as possible. The net zero journey must be a joint one and will be affected by how engaged and supportive the public are.

Across the Territory, the take-up of low emissions technologies is not limited to big business and industry. Households are increasingly adopting products and services that both reduce the cost of living and protect the environment through reduced emissions. Despite this support, there remains a lack of understanding of the rapid and societal transformations that will be required to achieve a net zero future by 2045.

The rollout of low-carbon solutions relies on positive public reception and demand to adopt them. Consumers need to have access to the right technologies, understand their benefits, and have confidence that they will be protected if they use them.

10.4 Technology considerations

The exact technology and energy mix leading up to 2045 cannot be known now, and the ACT's transition to net zero will respond to the innovation and adoption of new technologies over time. It is important to note that new innovations may emerge, enabling the market to move more quickly or at lower cost than expected, while in other areas progress may be hindered by unexpected deployment challenges as technologies are brought to scale.

The technologies that will be needed to achieve the transition of the energy sector towards a net zero future are already largely available, with many being economically competitive in commercial terms. The growth and maturity in global demand for low emissions products and services are driving down the prices for low emission technologies. It is expected that this reduction in costs will produce opportunities that support economic growth, employment opportunities and business competitiveness through adoption of those technologies that generate a cost saving in energy use.

With the transition also comes the possibly of high upfront capital costs associated with the deployment of some technologies (and related infrastructure) dependent on the scenario path that the Government selects. Examination and resolution of unnecessary barriers to entry for those specific technologies would need to be addressed to support net zero transition.

Further, the deployment of low emission products and services at scale does pose the potential for socio-economic challenges as they pertain to at-risk segments of society who cannot readily make the transition to low emissions technologies, given specific location or individual circumstance. Addressing socio-economic aspects of transitions will require currency of policies, programs, projects and actions that reflect community expectations with regards to affordability and equitable and just access for disadvantaged and vulnerable households.

10.5 Other transformation dependencies

10.5.1 Reforms focused on maintaining electricity system security and reliability

A key reform currently underway to support the energy transition in the NEM is the ESB *Post-2025 Market Design*. This is a collaborative work between all the market bodies to transition the NEM, which also includes the ACT, into a modern energy system to "… meet consumer's evolving need and demands".[43] Focus areas of the reforms under the ESB include:

- resource adequacy mechanisms to ensure that the ageing fleet of coal fired generators are replaced with renewable generation without affecting consumer reliability
- essential system services and scheduling, and ahead mechanisms, which are critical to ensure system security through the management of power system frequency, voltages and inertia
- integration of DER and flexible demand to leverage the continuously expanding installation of rooftop solar PV generation, and the expected uptake of residential batteries and electric vehicles
- transmission and access to the network for new generation, including governance around the development of renewable energy zones.

In addition to the broad ESB work across the NEM, are more specific initiatives, including national electricity rules changes such as the review of the NEM Reliability standard. The AEMC has recently extended the time for ruling on changes to the standard, with a final report by the Reliability panel due August 2022.[44] Once in place this will affect matters such as the Retailer Reliability Obligation (RRO), which determines the obligation to ensure resource adequacy, as well as how much energy a retailer must procure from renewable sources.

Continued observations of the developments coming from reforms such as these, amongst others will be important to ensure the ACT net zero initiative can benefit from the opportunities created thus created, as well as maintaining awareness of the fast-moving regulatory landscape within which the ACT initiative is being rolled out under.

10.5.2 Electricity infrastructure pipeline – accelerating investment

The future development of electrical infrastructure is crucial to the achievement of national and regional decarbonisation goals. The incentivisation of the development of sufficient infrastructure to connect future large scale renewable generation and the sending of the right signals to investors in renewable generation, are both needed to maintain security and reliability standards. To support this AEMO annually publishes the ESOO and biennially, the ISP. Together these documents outline opportunities and project the major infrastructure developments that will be needed in the NEM.

Separately, there are further rules changes underway or proposed to remove regulatory barriers to contestability of transmission development. To date, and outside of Victoria, only the incumbent state-based network service provider was permitted to operate electrical infrastructure in a given state. While the design and construction were able to be contested in many instances, the owning and operation of network assets was often viewed as the key incentive for

[43] **https://esb-post2025-market-design.aemc.gov.au/**
[44] **https://www.aemc.gov.au/rule-changes/extension-time-and-reduction-scope-2022-reliability-standard-and-settings-review**

investors. The AER is considering whether the introduction of full contestability to build, own and operate infrastructure across all regions would incentivise development and reduce overall costs to consumers.

Combined with the clear signalling of opportunities, and the removal of barriers to contestability, there are also reforms underway to make it easier to connect and operate large scale renewable generation[45]. If successful, these reforms will likely see an acceleration in the development of large-scale renewable generation, which in turn may bring about acceleration of infrastructure investments, as well as potentially continue to decrease the wholesale cost of electricity. Conversely it may also create more volatility in the market as we will likely see accelerated withdrawal of base load generation that could create more price volatility. In any case, developments in this space are important to consider in the ongoing development and implementation of the ACT Net Zero strategy.

10.5.3 NEM – improved policies

In addition to the reforms outlined in the previous subsections, there are a large number of initiatives underway to improve the efficiency and effectiveness of the NEM. AEMO is focused on a consumer centric evolving of the NEM to ensure reliable and affordable energy. There is more reform proposed by the market operator for many of the traditional process of managing the system. Many of these processes will not be fit for purpose in the future, as they are based largely on the generating fleets and technologies that were available at time of market start in the late 1990's. It will be important to maintain awareness of initiative proposed by AEMO in the operation and market management of the NEM as these will likely affect energy policy across the east coast regions.

Energy markets and power system operation are in turn affected by the rules and requirements that govern them. No more than in the NEM is the rate of change of new rules more apparent. The AEMC, the rules maker, generally has many rules changes that it is consulting on. These rules changes can be proposed by any electricity market participant and as such retailers, utilities, generators, and sometimes even large consumers will propose changes that they believe will improve the effectiveness of the NEM and support the achievement of the National Electricity Objectives.[46]

Development (and implementation) of any regional energy policy should consider the changes applied to the NER that will affect the realisation of such energy policy. Furthermore, the changes also reflect the sentiments of the NEM participants and can shed valuable insights into the issues that may affect the NEM as a whole or individual regions specifically.

[45] **https://aemo.com.au/en/newsroom/news-updates/cec-and-aemo-lead-grid-connections-reform**

[46] **https://www.aemc.gov.au/regulation/regulation#:~:text=The%20National%20Electricity%20Objective%20as,Electricity%20Law%20(NEL)%20is%3A&text=price%2C%20quality%2C%20safety%20and%20reliability,of%20the%20national%20electricity%20system.%22**

11. Recommendations

Findings set out in within this **Strategic Report** indicate that achieving a net zero economy is both technically and economically possible for the ACT by 2045. However, the pathway to getting to net zero will require significant transformational change – across both policy, regulation and activity-based initiatives to support community and industry action.

The Evoenergy gas network faces inevitable closure given current policy settings (no new connections). Collaboration between the ACT Government (as an owner), Evoenergy and AER will be critical for the purposes of establishing clear business planning for the network closure noting that the natural gas network future (and closure timing) will be determined by both the 'push' from consumers switching to electricity and 'pull' of distribution operator economics

However, the gas network tipping point is closer than envisaged with the economic drivers already in place. Some of the community will be disadvantaged if the transition (closure of the gas network) if not planned appropriately. To provide for an energy transition that considers the socio-economic impact on the most vulnerable in our community, greater insight is required as to tipping point issues from the distributor's viewpoint.

This will require early establishment activities that are focused on considering the key interactions between sectors, technologies and the energy system. Action premised on a whole-economy perspective, will provide for a more balanced and integrated approach to achieving net zero whilst ensuring a just transition to net zero emissions that supports the most vulnerable in our community.

The results of the of the scenario modelling and analysis set out in this **Strategic Report** suggest that whilst there are many different approaches to decarbonisation that could be pursued, a decentralised pathway akin to Scenario 2 would appear to offer the best overall benefits. This is due to expected benefits of cost, the long-term economic viability of the Evoenergy gas network and the forecast reduction in GHG emissions.

To confirm decarbonisation as the preferred pathway to a net zero emissions future, the ACT Government will need to undertake further work to support the analysis completed to date. Recommended early activities to support pathway confirmation are set out as follows:

RECOMMENDATIONS

1. Transition planning:

- **Recommendation 1(a)** Conduct in-depth studies to accurately identify the numbers and types of consumers who may face transition difficulty/limitations due to physical/legal constraints (building type/envelope; strata title restrictions); financial constraints (capital to transition); industrial (feedstock) requirements.
- **Recommendation 1(b)** Conduct in-depth studies as to residual gas customers - who, where located, barriers to transition/electrification, and possible alternatives.
- **Recommendation 1(c)** Develop policy and program options to ease the energy transition (especially for low-income households) for Government consideration.

2. Network impacts:

- **Recommendation 2(a)** Undertake a Feasibility Study as to options to convert parts of Evoenergy gas network to 'mini-systems' for the purposes of supplying large industrial users and niche applications, including options for hydrogen in such applications.

3. Renewable electricity:

An additional auction of renewable electricity will be necessary to maintain the ACT Government's commitment to 100 per cent renewable electricity in perpetuity, as included in modelling.

- **Recommendation 3(a)** Review the existing policy for calculating the commitment to 100 per cent renewable electricity to allow consideration and alignment with the 'greening' of the NEM, noting that this will have timing implications for auction purchases (and may reduce quantum).
- **Recommendation 3(b)** Review and confirm the role that carry-over credits will have in the scenario pathway adopted by Government.

4. Incentivising technology uptake:

As set out in the report across all scenarios, declining gas consumption will translate into increased electricity energy requirements, which can be offset by PVs, EVs and batteries (large-scale distributed and community batteries, behind-the-meter BESS and V2G/V2H) and the optimised deployment, uptake and placement of various DER.

- **Recommendation 4(a)** Investigate and develop economic drivers and options to incentivise the uptake of PVs and implement an appropriate program including the 'optimised' deployment, uptake and placement of various DER options.
- **Recommendation 4(b)** Investigate and develop economic drivers and options to incentivise the uptake of EVs, including an implementation program.
- **Recommendation 4(c)** Conduct more granular modelling of the network to optimise community battery deployment (including size, location, network implications) as optimisation of battery charge/discharge profiles for each location could significantly reduce investment.
- **Recommendation 4(d)** Conduct detailed modelling of V2H and V2G impacts - timing, quantum, network impacts and incentives to drive uptake.

5. RAB Investment:

RAB analysis conducted as part of this study was premised on limited commercial data. More detailed investment project scoping could determine with more accuracy material/labour breakdown improving the RAB determinations.

- **Recommendation 5(a)** Conduct more granular modelling of the RAB to improve the accuracy of investments needed to deliver electrification across the ACT through consideration of Evoenergy commercial data (asset lives; depreciation schedules etc).
- **Recommendation 5(b)** Drawing on improved RAB data, model the impact and implications for various parameters (e.g. PV, BESS, EV, V2H/V2G etc) for the preferred scenario to improve understanding of investment requirements and timing.
- **Recommendation 5(c)** Identify and establish linkages between significant Government infrastructure developments (current and planned) and network investment.

Appendices

Appendix A

Modelling assumptions

Core assumptions for electricity 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. <u>Wind</u> - $2,070/kW in 2021 - $1,780/kW in 2030 - $1,530/kW in 2040 - $1,445/kW in 2050 <u>Solar</u> (single axis tracking) - $1,435/kW in 2021 - $1,145/kW in 2030

Assumption	Basis for assumption
	- $960/kW in 2040 - $890/kW in 2050 Battery storage (four hours) 1. $1,745/kW in 2021 2. $1,035/kW in 2030 3. $885/kW in 2040 4. $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	
Purpose of modelling	- 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.
Assumptions that have minimal impact on the outcomes	

Assumption	Basis for assumption
Exchange rate	Market exchange rate: 0.75 AUD/USD
Consumer Price Index (CPI)	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 NSW and transmission augmentation costs are shared by all customers in ACT and NSW regardless of the location of the augmentation. Changes in transmission costs in the retail price in electricity have been forecast using wholesale electricity modelling assumptions.
Source: ACIL Allen	

Core assumptions for gas 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	1. Source of gas production is primarily east coast; including coal seam methane from Queensland 2. 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	
Purpose of modelling	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

Assumption	Basis for assumption
CPI	Treasury long term average target: 2.5% p.a.
Source: ACIL Allen	

Core components of the retail price impacts model

Assumption
- 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 - a further renewable electricity auction in 2025 - base case and all scenarios assume an additional 400 MW (2 x 200 MW wind farms) - 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.

Appendix B

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	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.

	out of fossil-fuel gas in the ACT, and demonstrate national best practice.	
	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 retrofitting of charging infrastructure in existing buildings.	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 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	In the absence of specific standards or energy efficiency outcomes to be delivered

	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 dwellings despite these constraints, with a goal of 600 additional dwellings by 2025-26.	by the additional public housing stock it is unclear how this materially impacts electricity demand. Not incorporated in the base case.
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	Unclear how this directly impacts electricity demand. Not incorporated in the base case.

	supply purposes, that are supported by the community.	
	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 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.	Unclear how this directly impacts electricity demand. Not incorporated in the base case.
	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	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.

	light rail networks through feeder services and expanding the Park and Ride network.	
	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 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.	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 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's 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
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.	

		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 - 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 C

Study models

GasMark

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

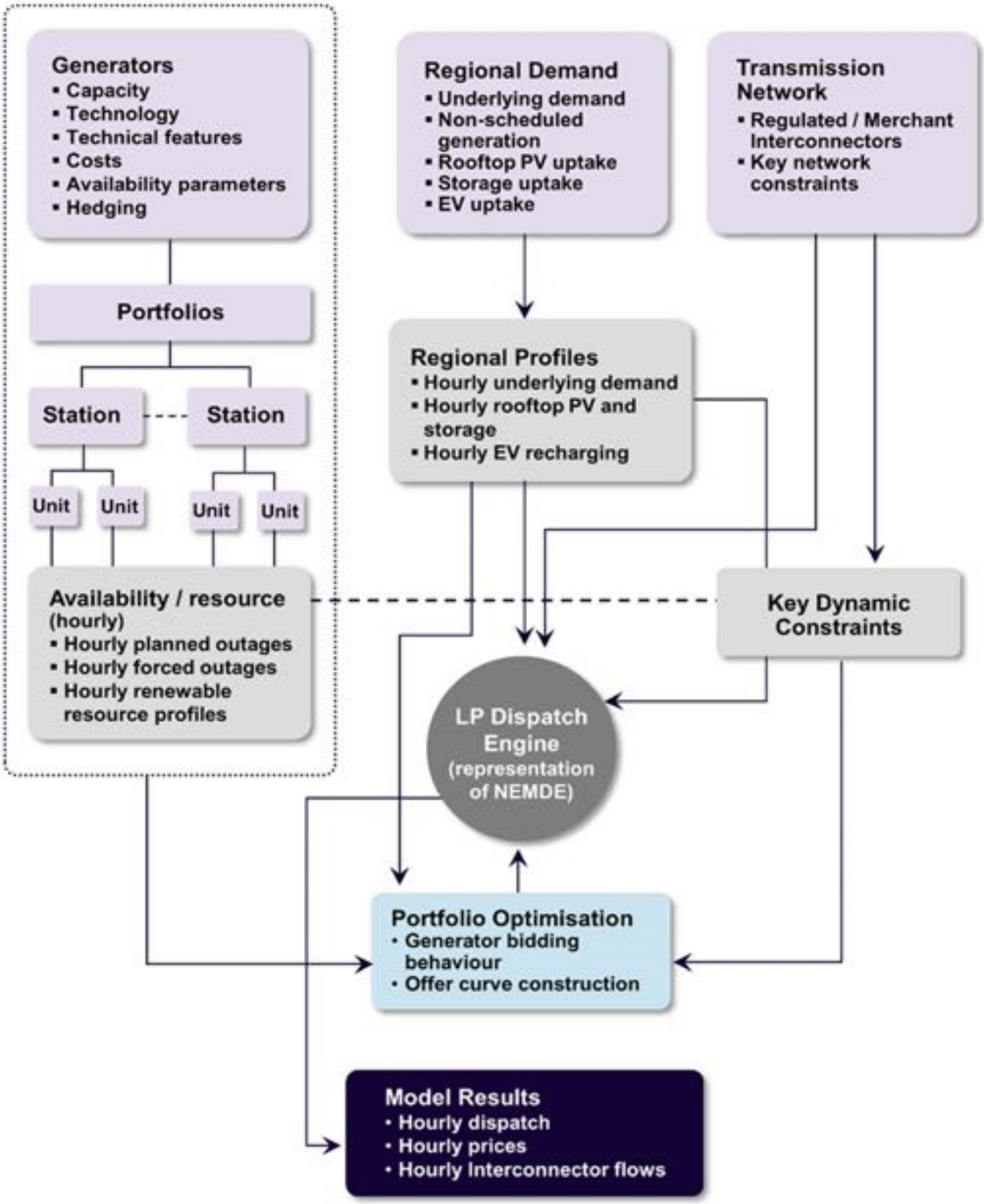
PowerMark has been developed over the past 20 years in parallel with the development of the NEM, the National Electricity Market of Singapore (NEMS) and the Philippine Wholesale Electricity Spot Market (WESM). ACIL Allen uses the model extensively in simulations and sensitivity analyses conducted on 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.



Tasman Global

Tasman Global is a dynamic, global computable general equilibrium (CGE) model that has been developed by ACIL Allen for the purpose of undertaking economic impact analysis at the regional, state, national and global level.

A CGE model captures the interlinkages between the markets of all commodities and factors, taking into account resource constraints, to find a simultaneous equilibrium in all markets. A global CGE model extends this interdependence of the markets across world regions and finds simultaneous equilibrium globally. A dynamic model adds onto this the interconnection of equilibrium economies across time periods. For example, investments made today are going to determine the capital stocks of tomorrow and hence future equilibrium outcomes depend on today's equilibrium outcome, and so on.

A dynamic global CGE model, such as *Tasman Global*, has the capability of addressing total, sectoral, spatial and temporal efficiency of resource allocation as it connects markets globally and over time. Being a recursively dynamic model, its ability to address temporal issues is limited. In particular, *Tasman Global* cannot typically address issues requiring partial or perfect foresight. However, as documented in Jakeman et al (2001), it is possible to introduce partial or perfect foresight in certain markets using algorithmic approaches. Notwithstanding this, the model does have the capability to project the economic impacts over time of given changes in policies, tastes and technologies in any region of the world economy on all sectors and agents of all regions of the world economy.

Tasman Global was developed from the 2001 version of the Global Trade and Environment Model (GTEM) developed by ABARE (Pant 2001) and has been evolving ever since. In turn, GTEM was developed out of the MEGABARE model (ABARE 1996), which contained significant advancements over the GTAP model of that time (Hertel 1997).

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before an economic disturbance and one following). A dynamic model such as *Tasman Global* is beneficial when analysing issues for which both the timing of and the adjustment path that economies follow are relevant in the analysis.

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database is derived from the Global Trade Analysis Project (GTAP) database (Aguiar et al. 2019). This database is a fully documented, publicly available global data base which contains complete bilateral trade information, transport and protection linkages among regions for all GTAP commodities.

Appendix D

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Appendix E

Stakeholder 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

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