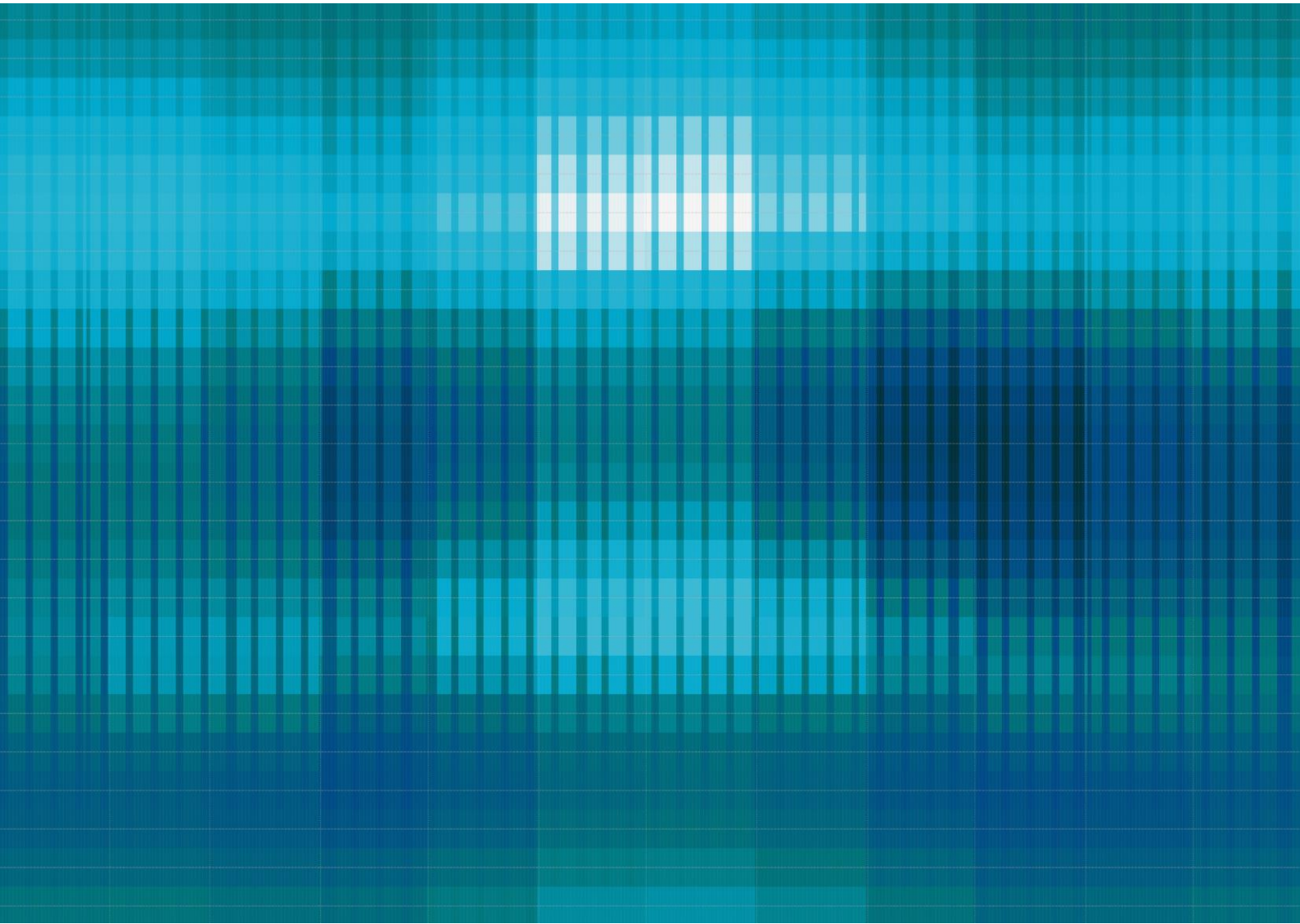




Towards FlexCost:

A method for estimating comparative costs of demand side resources

June 2026



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Acknowledgement of Country

CSIRO acknowledges the Traditional Owners of the lands, seas and waters of the areas that we live and work on across Australia and pays its respects to Elders past and present. CSIRO recognises that Aboriginal and Torres Strait Islander peoples have made, and will continue to make, extraordinary contributions to Australian life including in cultural, economic, and scientific domains.

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Cover image

The cover shows a stylised illustration of the variation in net demand in the National Electricity Market over 24 hours per day, 365 days per year, aggregated by month and workday/non-workday. For more about this and related images, refer to Section 2.3.

Foreword

When you go to the hardware store looking for a drill, what you typically want is a hole, not a drill. The same holds for our energy system - consumers do not want kilowatt hours or petajoules, they want hot showers, cold drinks, and reliable transportation.

Meeting consumer needs for energy services most affordably requires a paradigm shift in the way we plan our energy system. We can move away from presuming that the only approach is industry-owned and developed infrastructure, replete with faraway power plants and long transmission lines to bring them to our communities.

This report represents the first step in moving towards energy plans that enable a true comparison of different ways to meet our energy needs. FlexCost provides a methodology for valuing the efficient and flexible energy resources in consumers' homes and businesses, allowing them to be compared with supply-side options. Determining the true cost of "demand-side" energy resources increases the likelihood that we invest in the lowest-cost solutions to meet consumer needs and reduce energy costs for all.

Energy Consumers Australia is proud to have supported the development of the FlexCost methodology in partnership with CSIRO. As the national voice for household and small business energy consumers, we funded this work because better information leads to better decisions, which leads to better outcomes for consumers.



Brian Spak

General Manager, Advocacy and Policy



Table of Contents

Foreword	2
Abbreviations	5
Executive Summary	8
Key points	8
1 Introduction	12
1.1 Demand-Side Resources and the Energy Trilemma	12
1.2 The imperative for least cost energy solutions	13
1.3 The role of FlexCost	15
1.4 FlexCost Development and Consultation Process	19
1.5 Next steps	20
2 Defining energy resource requirements	21
2.1 Defining metrics for energy resources	21
2.2 Defining constrained energy periods	25
2.3 Electricity generation market constraints	26
2.4 Locational and network constraints	35
3 Selecting Demand-side Resources	38
3.1 Key concepts and definitions	38
3.2 Choosing Demand Flexibility options	39
3.3 Uptake potential - types of potential or factors outside costs	43
3.4 Relationship between cost and uptake	44
4 Defining costs of Demand-side Resources	49
4.1 Demand-side Resource Costs	49
4.2 Categorising costs	50
4.3 Costs inclusion/exclusion criteria	61
4.4 Levelised-cost of demand-side technology and facilitation	64
4.5 Methodological considerations, excluded costs and limitations of the analysis	65
4.6 Time horizon and learning curves	68
4.7 Operating modes	69
4.8 Data adequacy and data gathering	71
5 Flexible demand technologies	72

5.1	Home batteries (new & existing for coordinated dispatch)	73
5.2	EVs with smart charging.....	80
5.3	EVs with Vehicle to Home (V2H) or to Grid (V2G).....	85
5.4	Storage Water Heaters (solar soaking).....	93
5.5	Solar pre-cooling and pre-heating.....	99
5.6	Pool pumps and pool heaters (load shifting)	106
6	Energy efficiency technologies.....	111
6.1	Space heating and cooling upgrades.....	112
6.2	Insulation and thermal efficiency retrofits.....	116
6.3	Heat pump water heaters	120
6.4	Retirement and replacement of inefficient appliances	124
7	Illustrative inputs and outputs	128
	Appendix A: Managing uncertainty in forecasting energy constraints.....	132
	Appendix B: Technology Parameters	138
	References	147

Abbreviations

\$/kW-yr — Dollars per kilowatt per year (capacity or capacity deferral value)

\$/MWh — Dollars per megawatt-hour (energy value)

ACE — Available Coincident Energy (demand-side energy available in the specified period of analysis)

AEMO — Australian Energy Market Operator

AS/NZS — Australian/New Zealand Standard

BCA — Benefit-Cost Analysis

BCR — Benefit-Cost Ratio

BESS — Battery Energy Storage System

BOS — Balance-of-system

CCS2 — Combined Charging System 2

CER — Consumer Energy Resources

COP — Coefficient of Performance

CP — Constrained (energy) period. A period in which expected electricity demand may approach or exceed expected supply.

CPP — Critical Peak Pricing

DF — Demand Flexibility

DER — Distributed Energy Resources

DNSP — Distribution Network Service Provider, manages local distribution networks (poles and wires to homes/businesses)

DR — Demand Response

DRM1/DRM2/DRM3 ... — Demand Response Modes under AS/NZS 4755

DRPA — Demand Response Potential Assessment

DSOO — Demand-Side Statement of Opportunity (Australia).

DSR — Demand-Side Resources

ECA — Energy Consumers Australia

EE — Energy Efficiency

EER — Energy Efficiency Ratio

EV — Electric Vehicle

EVSE — Electric Vehicle Supply Equipment

Facil — Facilitation Cost perspective

FCAS — Frequency Control Ancillary Services

FR — Frequency Regulation

IRP — Integrated Resource Planning

ISO-NE — Independent System Operator – New England.

ISP — Integrated System Plan (AEMO)

LCODF — Levelised Cost of Demand-Side Facilitation (term proposed in this report)

LCODT — Levelised Cost of Demand-Side Technology (term proposed in this report)

LCOE — Levelised Cost of Electricity

LCOEF — Levelised Cost of Energy Flexibility

LCOF — Levelised Cost of Flexibility

LCOS — Levelised Cost of Storage

Meta — Metadata (parameters other than performance, CapEx/OpEx and performance, constraints)

NEM — National Electricity Market (Australia)

NPV — Net Present Value

O&M — Operation and maintenance

PAC (test) — Program Administrator Cost

PCT (test) — Participant Cost Test

PJM — PJM Interconnection

PoA — Period of analysis

PS — Peak Shaving

PV — Photovoltaics

RIM (test) — Ratepayer Impact Measure

RIS — Regulatory Impact Statement

RTE — Round-trip efficiency

RTP — Real-Time Pricing

SCT (test) — Societal Cost Test

SOC — state of charge (for batteries)

SOH — state of health

SR — Spinning Reserve

SRES — Small-scale Renewable Energy Scheme (Australia).

STC / STCs — Small-scale Technology Certificate(s) under SRES.

T&D — Transmission and Distribution (network).

Tech — Technology Cost Perspective

TNSP — Transmission Network Service Provider, manages high-voltage transmission networks

TOU — Time-of-Use (e.g. tariff).

TRC (test) — Total Resource Cost test

V2G — Vehicle-to-Grid

V2H — Vehicle-to-Home

VPP — Virtual Power Plant

Executive Summary

Since 2018, CSIRO has published the annual GenCost Report. The GenCost Report draws on the best available data and evidence to quantify the costs of generating electricity (including integration costs for renewable energy generation). Energy Consumers Australia has commissioned CSIRO to develop 'FlexCost' as a demand-side analogue of GenCost. To achieve this, FlexCost would be a standardised inventory of cost components and levelised unit costs for end-use demand flexibility and energy efficiency. With the rising share of generation coming from variable output wind and solar generation, flexible resources are becoming more important. With the shift towards electrification, greater efficiency of electricity use is also becoming more crucial.

FlexCost will aim to evaluate demand-side options that can substitute for supply-side investment. Developing a demand-side complement to GenCost can help to ensure that demand flexibility and energy efficiency options are valued on a comparable basis with generation and storage technologies. FlexCost will be designed to characterise the indicative costs and potential quantities of demand flexibility and energy efficiency measures.

The proposed future FlexCost reports are intended to serve as a tool to identify representative and actionable demand flexibility and energy efficiency options that are technically viable, economically efficient, and practically achievable. FlexCost is intended to support consistent cost comparison of demand-side options with each other and with generation and network investments in planning and policy contexts.

The aim of this report is to establish the methodological foundation for the proposed inaugural FlexCost Report. As is the case for GenCost, CSIRO expects that stakeholder consultation and feedback will be crucial for developing FlexCost. It is hoped that the first FlexCost Report will provide a basis for continual improvement in subsequent FlexCost Reports.

Key points

The key points below summarise of the proposed FlexCost method. Each chapter's key points are also listed at the beginning of the respective chapter.

Chapter 1. Introduction

It is proposed that this FlexCost method is applied to estimating the generic cost components and levelised unit costs of demand-side resources in the Australian electricity system. This FlexCost method should:

- Provide a robust, evidence-based inventory of generic cost components and unit costs for demand flexibility and end-use energy efficiency improvement.
- Seek to emulate and follow the precedents of GenCost wherever possible and appropriate.
- Be developed in effective consultation with key stakeholders.

Chapter 2. Defining energy resource requirements

It is proposed that the FlexCost method should:

- Focus on the cost of demand-side resources providing energy to address specified periods, rather the cost of providing ‘anytime’ energy.
- Consider both expected net supply (expected supply minus expected demand), and wholesale spot market prices as useful proxies for defining electricity energy constraints.
- Adopt a set of standard ‘Periods of Analysis’ (PoA), that are the nominated number of hours of the year when demand-side resources are expected to be most needed, such as the top 50 most constrained or highest market price hours of the year.
- Adopt $\$/\text{MWh}_{\text{PoA}}$ as the primary unit of levelised cost of demand-side resources, where $\$/\text{cost}$ refers to the Technology costs or the Facilitation costs, and MWh_{PoA} refers to the Available Coincident Energy from Demand-side Resources within the nominated Period of Analysis.
- Consider four specified Periods of Analysis: ‘Acute Constraint’ (50 most constrained hours per year – 0.6% of the year), ‘Broad Constraint’ (500 most constrained hours per year – 6% of the year), ‘Daily Evening Peak’ (1,825 hours – 20.8% of the year) and Bulk Energy (7,900 hour per year – 90% of the year).
- For simplicity and data accessibility, focus in the first instance on the generation energy market data, rather than network conditions, for defining energy constraints and constrained periods.
- Recognise that network constraints may be just as significant as energy market constraints and are therefore worthy of future analysis.
- Use historical energy market constraint data and extrapolated current trend data for forecasting future energy constraints, while recognising that more sophisticated statistical approaches should be considered in future.

Chapter 3. Selecting Demand-side Resources

It is proposed that FlexCost method should:

- Apply explicit criteria in selecting which demand-side technologies to include in the first version of the FlexCost Report. Suggested inclusion criteria discussed in the method report: potential impact, materiality, comparability, actionability and data availability.
- Focus in the first version of the FlexCost Report on technology-based rather than behaviour-based demand-side measures.
- Focus in the first version of the FlexCost Report on incentive-based rather than pricing-based instruments.
- Focus on ‘achievable potential’, which recognises practical implementation limits, in assessing the cost of demand-side resources, while also considering technical and economic potential, where relevant or appropriate.
- Make clear that the unit cost of deploying demand resources can vary significantly depending on the level of uptake of these resources, and this cost/uptake relationship is critical to estimating demand-side resource costs.

Chapter 4. Defining costs of Demand-side Resources

It is proposed that FlexCost method should:

- Apply explicit criteria in selecting which cost categories to include. Inclusion criteria should include: materiality, data robustness and methodological consistency.
- Consider technology costs and facilitation costs in estimating costs of demand-side resources.
- Focus on facilitation costs as the most material costs for estimating the net impact on customers as a whole.
- Focus on the *additional* cost for facilitating *additional* demand-side resources, rather than on the existing or 'business as usual' cost of existing or business as usual demand-side resources.
- Present both cost components and aggregated levelised costs of demand-side resources.
- Include the following components in applied Technology Costs formula: capital cost and operating cost. (Associated system costs, including network costs, should be considered, but not quantified in the first FlexCost Report.)
- Consider the following components in Facilitation Costs: incentive costs, administration costs, free rider/free driver impacts.
- Present levelised costs both as Levelised Cost of Demand-side Technology (LCODT) and separately as Levelised Cost of Demand-side Facilitation (LCODF).
- Calculate levelised costs of demand-side resources based on cost per unit of available energy coinciding with each Period of Analysis.
- Focus on current costs rather than future costs of demand-side resources in the first version of the FlexCost Report, but also note any significant anticipated shifts in costs or technology over the next decade and consider sensitivity to different assumptions.

Chapter 5. Flexible demand technologies

Based on the selection criteria discussed in Chapter 4, it is proposed that the first version of FlexCost Report should study the following demand flexibility technologies:

- Home batteries (new & existing for coordinated dispatch)
- EVs with smart charging
- EVs with Vehicle to Home (V2H) and Vehicle to Grid (V2G)
- Storage Water Heaters (solar soaking)
- Solar pre-cooling and pre-heating
- Pool pumps and pool heaters

Chapter 6. Energy efficiency technologies

It is proposed that the first version of FlexCost Report should study the following energy efficiency technologies:

- Space heating and cooling upgrades
- Insulation and thermal efficiency retrofits

- Heat pump water heaters
- Retirement and replacement of inefficient appliances

Chapter 7. Illustrative Inputs and Outputs

It is proposed that the first version of the FlexCost Report should:

- Clearly spell out the specific data inputs and outputs of FlexCost.
- Make clear that the first version of the FlexCost Report is presented as an initial ‘minimum viable product’, rather than a mature, fully developed version comparable to GenCost which has evolved over an eight-year period.
- Identify areas for improvement in future iterations of the FlexCost report

1 Introduction

Key points

It is proposed that this FlexCost method is applied to estimating the generic unit costs of demand-side resources in the Australian electricity system. This FlexCost method should:

- Provide a robust, evidence-based inventory of generic unit costs for demand flexibility and end-use energy efficiency improvement.
- Seek to emulate and follow the precedents of GenCost wherever possible and appropriate.
- Be developed in effective consultation with key stakeholders.

1.1 Demand-Side Resources and the Energy Trilemma

The need to address climate change is now widely understood. To achieve rapid decarbonisation while protecting living standards and maintaining social cohesion, it is essential that decarbonisation of energy delivers reliable power at low cost for consumers. This is the core of the so-called 'Energy Trilemma': meeting the community's energy needs while enhancing Reliability, Affordability and Sustainability.

Achieving an energy transition at the lowest total economic cost requires the optimal mix of energy supply resources (centralised generators, storage and networks), and 'demand-side resources' that improve the efficiency of energy use and modify or 'flex' demand to reduce electricity peak demand or bridge the gap between energy demand and supply.

Based on the precedent of CSIRO's series of GenCost reports (CSIRO, 2025c) which estimate the cost of large-scale electricity generation and storage, and the need for more reliable and consistent valuation of demand-side resources, Energy Consumers Australia (ECA) commissioned CSIRO to consider the feasibility of developing a demand-side analogue of GenCost. FlexCost aims to catalogue indicative unit costs for end use demand flexibility and energy efficiency options, with a focus on residential and small business sectors.

The FlexCost reports are envisaged to serve as a tool to identify representative and actionable demand flexibility and energy efficiency options that are technically viable, economically efficient, and practically achievable. FlexCost analysis is intended to support consistent valuation of demand-side options and their comparison with generation and network investments in planning and policy contexts. The aim of this first stage project is to establish the methodological foundation for a proposed inaugural FlexCost Report.

Demand-side Resources (DSR) include technologies and practices that generate energy (like rooftop solar), store energy (like batteries and EVs), save or shift energy (like insulation or smart controls) at or near where it is used, that is in the homes and businesses of energy users. 'Demand-side Resources' is similar in meaning to 'Consumer Energy Resources' (CER), except that Demand-side Resources explicitly includes improving end use energy efficiency, while CER sometimes omits energy efficiency. For clarity, this report uses the term Demand-side Resources to refer to customer-focussed Demand Flexibility and Energy Efficiency.

Demand flexibility (DF) refers to how electricity users or devices can adjust their consumption or generation in response to price, system signals, or incentives. Demand flexibility includes both long-established practices, such as end users shifting load to off-peak periods, and more novel approaches in which devices automatically change their use in real time. Demand flexibility allows network and system operators and other aggregators to coordinate CER more effectively, and for price-exposed retailers and consumers to reduce their electricity costs.

End use energy efficiency (EE) can be defined as “persistent ... reduction in energy and/or demand, as compared to baseline consumption, to provide the same or an improved level of service” (Satchwell et al., 2020). Energy efficiency complements demand flexibility by reducing overall energy consumption and improving the performance of end-use technologies. Implicitly, energy efficiency may also reduce peak demand and equipment capacity required.

Demand flexibility is delivered in Australia through market-based mechanisms (e.g. NSW Peak Demand Reduction Scheme), standards (AS 4755 - Demand Response Standard), and codes, which also underpin many flexibility measures. Similarly, EE is delivered through a mix of regulatory instruments (e.g. Australian Building Code (Australian Building Codes Board, 2025) for new homes and Greenhouse and Energy Minimum Standards for appliances) and market-based mechanisms (NSW/ACT Energy Saving Scheme, Victorian Energy Upgrades, South Australian Retailer Energy Productivity Scheme), including schemes such as white certificates (CSIRO, 2024b). When co-optimised, energy efficiency and demand flexibility can provide both structural and operational benefits to the power system.

1.2 The imperative for least cost energy solutions

The accelerating shift toward electrification, coupled with the rapid retirement of ageing coal-fired power stations, and the integration of variable renewable energy represents a fundamental transformation of the electricity grid. These factors make delivering energy services at the lowest cost more critical than ever. Moreover, the recent global fuel crisis has elevated energy security and electrification concerns, as nations seek to insulate their domestic economies from volatile international energy markets. Electricity is an essential service and a fundamental input to the economy. Maintaining low energy system costs and prices are a key policy objective for government. This is an economy-wide concern given the role of energy prices in inflation, and it is central to consumer affordability, cost of living pressures, energy security, and social licence for the energy transition.

Electricity bills can be reduced through measures that shift either supply or demand. Australia has large, untapped opportunities to invest in demand-side resources and has a mediocre ranking for energy efficiency performance compared to many other countries (ACEEE, 2025). Scaling up demand flexibility and energy efficiency has the potential to lower overall system costs and electricity bills for all consumers, while also enabling additional bill savings for households and businesses that choose to adopt these demand-side resources.

The ultimate purpose of the energy system is to meet consumer needs for energy services, such as illumination, refrigeration, hot water, comfort (warmth and cooling), cooking, transportation, access to services and manufacturing, etc. The delivery of electricity or natural gas is simply a means to this end that also relies on end-use technologies and user behaviour. The energy system

offers alternative ways to provide these energy services. These ways include: traditional infrastructure (large power plants, poles, and wires); through energy efficiency (a more efficient light or refrigerator offers the same services while requiring less infrastructure); or through distributed generation and storage, which provides energy locally. All these means have a role to play but have different cost profiles and consumer impacts. The traditional energy system has focussed heavily on supply-side resources, creating a risk that lower-cost pathways or options that deliver consumer value beyond energy cost savings might be overlooked.

Identifying and adopting the most cost-effective combination of energy resources is crucial to support a shift toward a low-carbon energy system and to address emerging generation and network constraints. This is particularly so given that Australia is struggling to deploy supply side resources fast enough to match the retirement of coal-fired power stations and the trend toward electrification. Many latent demand-side resources may already be available and waiting to be used or may be faster to deploy if not already available.

Most of Australia's presently operating coal-fired power stations are due to retire over the next two decades, and there is an increasing need for more scheduled and unscheduled maintenance in the interim. This creates a demand for low-cost alternatives to replace or avoid the need for both this generation capacity (measured in kilowatts; kW) and the energy it provides (measured in kilowatt-hours; kWh).

Most renewable energy resources in Australia are variable output wind and solar generation. This supply variability makes it harder to keep supply and demand balanced in real time. Using demand-side flexibility to adjust the demand of electricity consumers in the light of supply variability could reduce the overall cost of the electricity system to meet consumer energy needs.

Depending on costs, operational characteristics, and the application of appropriate risk-adjusted valuation frameworks, demand-side resources may provide a viable alternative to large-scale battery energy storage and gas peaker plants. Complementing demand flexibility resources that can target short term constraints, are more broadly available demand reductions through energy efficiency improvements. Indeed, energy efficiency has been described by the International Energy Agency as "the unambiguous first and best response to simultaneously meet affordability, supply security and climate goals" (IEA, 2025a). On the other hand, energy efficiency is often obstructed by various institutional barriers such as split incentives, payback gaps and lack of reliable information.

GenCost is a series of regularly updated reports, published since 2018, which provide detailed indicative and credible costing of supply-side options (CSIRO, 2025c). The FlexCost project aims to complement this analysis, ensuring that demand-side options are evaluated with the same level of rigour and objective data. By identifying and quantifying the costs of demand-side resources, many of which can be implemented more quickly than traditional supply side infrastructure, the FlexCost project seeks to provide the evidence base to ensure that other cost-effective energy solutions are not overlooked.

Existing policy and market settings have successfully encouraged adoption of some Demand-side Resources. However, such settings may be insufficient to drive the optimal level of Demand-side Resources uptake and CER orchestration for least cost outcomes, or to realise AEMO's Step Change scenario and Australia's net zero 2050 targets. Under current arrangements, Demand-side

Resources are inconsistently rewarded, and renters and low-income households are largely excluded due to financial and regulatory barriers.

Although previous strong financial returns on rooftop solar have been eroded by high adoption rates and corresponding declines in feed-in tariffs, these factors have accelerated the adoption of residential battery storage as consumers seek to maximise self-consumption and hedge against rising retail prices. The battery installation ‘boom’ reflects a growing and significant potential to transition from a passive export model to a more active, independence-focussed customer strategy. Furthermore, structural regulatory barriers have prevailed, where network incentive frameworks are often seen to favour capital-intensive ‘poles and wires’ investment (CapEx) over the orchestration deployment of non-network alternatives, such as demand-side resources and CER.

The current policy and market settings could lead to higher electricity and network costs, slower emissions reductions, and more limited opportunities for active management by households and businesses of their energy use. Recent policy analyses have advocated for a more balanced approach that integrates emission reduction goals with efficient use of both consumer and network resources (Kuiper and McConnell, 2025). Projections of a 50% increase in peak household electricity demand by 2050, alongside rising electricity bills despite until recently declining petrol costs, further highlight the urgency of coordinated demand-side action. In light of more recent events, record-high fuel prices are both a major economic pain point and a structural accelerant for consumers to adopt EVs and household electrification, making efficient integration of these new loads a critical priority for grid stability.

1.3 The role of FlexCost

What is GenCost and how will FlexCost complement it?

GenCost report arguably provides Australia’s most prominent and widely used reference for the cost of supply-side technologies. Led jointly by CSIRO and the Australian Energy Market Operator (AEMO), GenCost publishes annually updated techno-economic input data for existing and emerging generation and storage technologies, including capital, operating and fuel costs as well as key technical performance assumptions, for use in studies such as AEMO’s Integrated System Plan (ISP). In addition, it reports levelised cost of electricity (LCOE) estimates as a high-level screening metric for comparing *individual* generation technologies on a consistent basis, and system levelised cost of electricity (SLCOE) estimates as a system-wide metric for comparing the average cost of least-cost technology portfolios (including integration and transmission requirements) under defined scenarios.

However, no equivalent framework currently exists for Demand-side Resources, despite the substantial growth in adoption of CER such as rooftop solar, batteries and electric vehicles.

FlexCost is proposed as a demand-side analogue of GenCost: an inventory of generic unit costs for end-use demand flexibility and energy efficiency. Developing a demand-side complement to GenCost can help to ensure that flexibility and efficiency options are valued on a comparable basis with generation and storage technologies. FlexCost is designed to address this gap by characterising the indicative costs and potential quantities of demand flexibility and energy efficiency measures. While GenCost quantifies the costs of generating electricity and integration

costs for renewable generation, FlexCost aims to evaluate demand-side options that can substitute for supply-side investment. The two frameworks are complementary; together they would enable integrated assessment of both supply and demand-side resources, supporting balanced investment decisions and more inclusive least-cost system planning.

GenCost reports are deliberately a cost-focused framework as it characterises the costs of alternative supply-side technologies. In essence, GenCost does not attempt to quantify the associated 'downstream' costs of delivering this generated power to consumers, such as transmission and distribution network costs. On the other hand, Demand-side resources can, to varying degrees, do provide an alternative for both generation, and network supply.

GenCost analysis also does not consider the broader system, customer, or societal and environmental costs and benefits those technologies may deliver. This 'direct cost-only' approach is appropriate for its primary purpose as a supply-side screening tool.

An important methodological choice for FlexCost is whether to consider only current capital costs or also to consider future costs. GenCost reports provide projections of the capital costs up to 2055 of the supply-side generation resources. On the demand-side, some flexibility and efficiency options are not yet deployed at scale, and their purchase costs are expected to decrease as volumes increase and technologies mature. Limiting analysis to current conditions and incremental change at a time of disruptive change could overstate long-term costs and understate potential competitiveness. Therefore, although initially focusing on current costs and understanding how potential changes in the market could affect these, over time FlexCost intends to present both current and forward-looking cost cases over a predefined horizon (e.g. 10 years).

For demand-side resources, a direct cost only approach can also be applied, but it is important to ensure that if compared to the supply side, the full corresponding supply side costs are also considered. Due to their location at or close to the point of use, demand-side resources can substitute for generation resources, while also reducing or deferring associated network costs. Accordingly, if demand-side resources can substitute for both generation and network combined, then the cost of demand-side resources should be compared against the equivalent total cost of generation and network alternatives.

Both supply side and demand-side resources have potential to lower operational costs, improve reliability and resilience, and deliver co-benefits such as emissions reductions. Some demand-side resources, such as residential energy efficiency can offer other potential benefits such as improved comfort and health. These additional benefits are important, but they are outside the scope of FlexCost, which, like GenCost, focusses on direct cost inputs rather than wider, non-economic, system, 'externalities' or social benefits. While this work adopts a conservative perspective, it is worth noting the IEA suggests that these multiple benefits can be worth more than double the energy cost savings (IEA, 2025b).

Demand flexibility resources have an additional benefit in that they can potentially address circumstances of shortfalls in both energy generation and energy demand. A home battery or an electric vehicle acts as a load when it is charging, but it acts as generation capacity when it discharges power back into the house or the grid. GenCost is not focussed on the 'load' side, because it is interested in the cost of providing new electricity supply (supply to grid).

Furthermore, GenCost is focussed on the ‘bulk supply’ of electricity throughout the year, while the intent is for FlexCost to be focussed mainly on short periods of the greatest gap between demand and supply (and highest cost) in the electricity system.

Therefore, in the ‘LCOE’ costs of new generation in GenCost will not be directly comparable to the cost of demand-side resources in FlexCost. Further analysis of generation costs would be required to provide a like for like comparison for the cost of addressing ‘peak demand’ or constrained periods, by for example, comparing with levelised costs of low capacity-factor open cycle gas turbine generators with the cost of batteries or other demand-side resources for the constrained periods that FlexCost is addressing.

Potential applications of FlexCost:

By providing a standardised evidence-based inventory of cost of demand-side resources, FlexCost could support two main application areas:

1. Cost inputs for electricity system planning (DF and EE), including
 - a. Planning assumptions and inputs (rather than metrics) for AEMO’s ISP, enabling demand-side flexibility and energy efficiency to be assessed alongside supply-side options.
 - b. Direct inputs to the proposed Demand-side Statement of Opportunities (DSOO), including consistent cost assumptions for demand-side options.
 - c. Distribution network planning, including approaches such as the Distribution Annual Planning Reports and the Integrated Distribution System Plan that DNSPs have to produce, through consistent demand-side cost inputs.
 - d. Least-cost modelling and investment comparison, enabling planners to compare demand-side options against supply-side investments to assess cost-effectiveness and identify an appropriate least-cost mix.
2. An evidence base for least-cost energy policy and program design, using cost comparisons both between different demand-side resources, and between demand-side and supply-side resources.

FlexCost is not intended to model the energy system or calculate system benefits. However, FlexCost data may provide useful inputs for planners and analysts to undertake such modelling.

For example, AEMO’s Integrated System Plan (ISP) guides long-term generation and transmission network investment in the NEM. It sets out the generation, storage and transmission network portfolio required to meet consumer demand consistent with government energy and emissions targets to 2050. The ISP aims to make full use of opportunities from existing technologies and expected innovations in energy resources, large-scale generation, networks, and related sectors such as gas and transport.

Although the ISP considers Demand-side Resources, including rooftop PV, batteries, EVs and energy efficiency, it does so as a set of input assumptions which exogenously impact on forecast operational demand in the wholesale electricity market. The ISP modelling does not optimise the adoption of Demand-side Resources. One perspective on the role of the ISP is that it should

analyse the opportunities to avoid generation and storage and transmission and distribution (T&D) investments via greater adoption of demand-side resources.¹ By including and comparing all potential ways to achieve a supply-demand balance, such analysis would help ensure electricity is delivered at the lowest possible cost in the long term for consumers.

From a wider energy and climate policy perspective, the Australian Government's Net Zero Plan sets out strategies for electricity and energy and for the built environment, and the Trajectory for Low Energy Buildings also highlights the role of demand-side measures (Australian Government, 2025b). The Net Zero Plan indicates that improved energy performance, appliance efficiency and demand flexibility are expected to support emissions reduction, system reliability and cost management. The built environment sector plan particularly emphasises appliance efficiency and demand flexibility.

The Net Zero Plan's electricity and energy sector plan connects improved end-use performance and flexibility to the demand-side opportunities identified in the proposed Demand-Side Statement of Opportunity (DSOO) (DCCEEW, 2025a). Together, these developments support the need for robust, transparent valuation frameworks that capture both the economic and operational benefits of demand-side participation. A data source such as FlexCost inherently focusing on load and generation will therefore complement GenCost by providing the demand-side data required to inform integrated resource planning and guide the transition toward a secure, low-carbon, electricity system.

Energy sector policy and market settings are being revised to consider both energy efficiency and demand flexibility as essential components of modern resource planning, as described below. The new approach values not only reduced consumption but also the ability to shift and manage demand in time and location in order to capture broader system, reliability, and decarbonisation benefits.

In Australia, policy and market settings have been revised in some jurisdictions to incorporate flexibility alongside efficiency through different approaches. In New South Wales this is achieved through the Peak Demand Reduction Scheme (PDRS). The PDRS creates tradable peak reduction certificates via three methods: peak-coincident efficiency, event-based response, and load shifting. Recent rule updates have formalised the participation of batteries and virtual power plants, and commenced staged changes from September 2025 to include these flexible resources in the scheme's valuation and compliance framework. In South Australia, the Office of the Technical Regulator's guideline on DR requirements for air conditioners (Version 1.2, April 2025) mandates that all new residential air conditioners installed in the state be equipped with demand-response capability compliant with AS/NZS 4755 standards. Based on this requirement, everyday household devices can be remotely signalled to reduce or shift load. Nevertheless, there are still substantial gaps in how 'VPP-readiness' is defined and that a reliance on hardware-based mandates may unnecessarily increase installation costs compared to internet-based alternatives. To reach maturity, a case can be argued in favour of these pathways shifting from 'blunt' hardware

¹ Note that DSR uptake recommendations were outside the original scope and purpose of the ISP.

signals toward the sophisticated software orchestration already demonstrated by the solar industry.

At the national scale, the small-scale renewable energy scheme (SRES) supports CER by awarding small-scale technology certificates (STCs) to eligible systems based on the amount of renewable electricity they generate, store, or displace. It applies to small-scale solar systems - including rooftop solar, solar water heaters and air-source heat pumps - as well as small-scale wind and hydro systems. The SRES has recently been extended to solar batteries through the Cheaper Home Battery program. These policy developments indicate the need for consistent and transparent cost benchmarks to inform scheme design, valuation methods, and prioritisation of demand-side measures.

1.4 FlexCost Development and Consultation Process

CSIRO proposes to adopt stakeholder consultation as its primary engagement mode for developing the FlexCost report. The project is designed to be informed by stakeholders; however, final decisions regarding method, assumptions, and outputs will remain with CSIRO. This approach is necessary to maintain independence, scientific merit, and robustness.

The consultation approach development draws on lessons from the GenCost project and CSIRO's experience in national energy consultation processes, including AEMO's ISP, which represents one of the most mature consultation frameworks in the Australian electricity sector.

Purpose of stakeholder consultation:

Demand flexibility and energy efficiency are complex and vary by customer, technology, location, and time. As with GenCost, consultation with stakeholders would improve FlexCost quality by incorporating external technical expertise and broader contextual perspectives beyond internal engineering analysis. Consultation, like in the GenCost project can help with identifying a series of analysis parameters and sourcing data. As demand-side resource uptake affects many stakeholders, early consultation can also reduce resistance by allowing affected parties to inform how opportunities and constraints are framed, provided input is documented, reasonably acted upon, and received early enough to influence outputs.

FlexCost also depends on stakeholder confidence in the objectivity and accuracy of its results, which is strengthened through transparent assumptions, consistent opportunities for input, and clear reporting of how feedback influenced outcomes, with ongoing annual consultation supporting continuous improvement over time.

Consultation process outline:

Considering the purpose of consultation outlined above, FlexCost will implement a structured process to obtain, assess, and respond to stakeholder input while maintaining CSIRO's decision-making responsibility:

1. Publish a draft methodology report for review.
2. Consult with key stakeholders (including DCCEE, AEMO, AEMC, AER, the DCCEE CER Advisory Group, and the CER experts).
3. Collect and review stakeholder submissions and technical input.

4. Incorporate method updates where appropriate and within scope.
5. Publish a consultation summary outlining what changed, what did not, and the rationale.
6. Publish the final methodology report.
7. Maintain an ongoing update cycle to inform future versions.

1.5 Next steps

This report provides the Stage 1 methodology foundation for FlexCost, which establishes the scope, analytical approach, and evidentiary basis required to estimate the costs of demand-side resources for the residential and small business sectors.

It is proposed that the Stage 2 of this project will apply the methodology proposed in this report to produce the inaugural 'minimum viable product' first FlexCost Report. This will commence with model validation and refinement, establishment of reproducible calculations, and implementation of a consistent workflow that links raw cost inputs (e.g., capital and fixed/variable operating costs) to aggregated outputs (e.g. levelised metrics per unit of energy).

This version will then prioritise structured data collection using the analytical template proposed herein, with evidence sources documented for traceability and supported by clear assumptions, data quality criteria, and version control. Stage 2 will also expand the scope to include commercial and industrial sectors

Quantitative analysis will generate the core reporting outputs, including tabulated cost estimates and graphical summaries where appropriate, supported by sensitivity analysis to address uncertainty. A wider and more structured consultation cycle than that followed for this FlexCost Method Report will be undertaken to test key assumptions, validate data selections, and review draft outputs prior to publication. Stage 2 will conclude with drafting and publishing the first FlexCost Report, alongside knowledge sharing to support end-user interpretation and to inform the subsequent.

The FlexCost report is proposed to continue to develop beyond a 'minimum viable product' over future iterations based on stakeholders' input and support.

2 Defining energy resource requirements

Key points

It is proposed that the FlexCost method should:

- Focus on the cost of demand-side resources providing energy to address specified periods, rather the cost of providing ‘anytime’ energy.
- Consider both expected net supply (expected supply minus expected demand), and wholesale spot market prices as useful proxies for defining electricity energy constraints.
- Adopt a set of standard ‘Periods of Analysis’ (PoA), that are the nominated number of hours of the year when demand-side resources are expected to be most needed, such as the top 50 most constrained or highest market price hours of the year.
- Adopt $\$/\text{MWh}_{\text{PoA}}$ as the primary unit of levelised cost of demand-side resources, where $\$/\text{cost}$ refers to the Technology costs or the Facilitation costs, and MWh_{PoA} refers to the Available Coincident Energy from Demand Side Resources within the nominated period of analysis.
- Consider four specified Periods of Analysis: ‘Acute Constraint’ (50 most constrained hours per year – 0.6% of the year), ‘Broad Constraint’ (500 most constrained hours per year – 6% of the year), ‘Daily Evening Peak’ (1,825 hours – 21% of the year) and Bulk Energy (7,900 hours per year – 90% of the year).
- For simplicity and data accessibility reasons, focus in the first instance is on the generation energy market data, rather than network conditions, for defining energy constraints and constrained periods.
- Recognise that network constraints may be just as significant as energy market constraints and therefore worthy of future analysis.
- Use historical energy market constraint data and extrapolated current trend data for forecasting future energy constraints, while recognising that more sophisticated statistical approaches should be considered in future.

2.1 Defining metrics for energy resources

For any planning process to acquire additional (supply-side or demand-side) resources for the electricity sector, it is necessary to forecast or specify the need for additional resources. To do this, and to estimate how much it might cost to meet this requirement, it is first necessary to define units of measurement of this requirement.

To allow for comparison between demand-side resources (DF and EE) and supply-side resources (centralised generation and storage), we must define a common metric or measurement unit.

The cost of supply-side resources is conventionally measured in terms of dollars per MWh, as shown in Figure 1 (from the GenCost Report (CSIRO, 2025c)). It would therefore be convenient if the need for resources (either supply-side or demand-side) could be defined in the same terms, that is, MWh.

However, for electricity, timing matters on both the supply and demand sides, so not all MWh are equally valuable. At times of scarcity, such as at times of peak demand or system constraint, electricity is often much more valuable than at times of relative generation abundance. An extra MWh of generation, from rooftop solar in the middle of the day, may be of very little value if supply already exceeds demand. On the other hand, an extra MWh of energy from a battery or from reduction in demand in the early evening on a day of peak demand, may be extremely valuable if it prevents load shedding and keeps essential loads powered, such as preserving refrigerated medicine or keeping telecommunications operational.

The time varying value of electricity has always been a feature of the electricity system. Demand fluctuates and constraints occur from time to time, requiring high-cost assets, such as peaking generators or energy storage, that are used infrequently. However, the increasing challenge of matching variable demand with supply from variable output renewable generation, means that the time dimension of electricity supply and use is becoming increasingly important.

Figure 1 shows the cost of ‘bulk supply’ generation, which can provide power for very long periods, and in this case refers to providing energy for up to 90% of the time. Even though wind and solar are very variable in their generation output, firmed-up solar and wind are shown as having ‘comparable’ cost to black coal and gas fired generation. The energy storage used for firming can absorb surplus electricity when it is abundant and less valuable and provide it back to the system when electricity is relatively scarce and therefore more valuable.

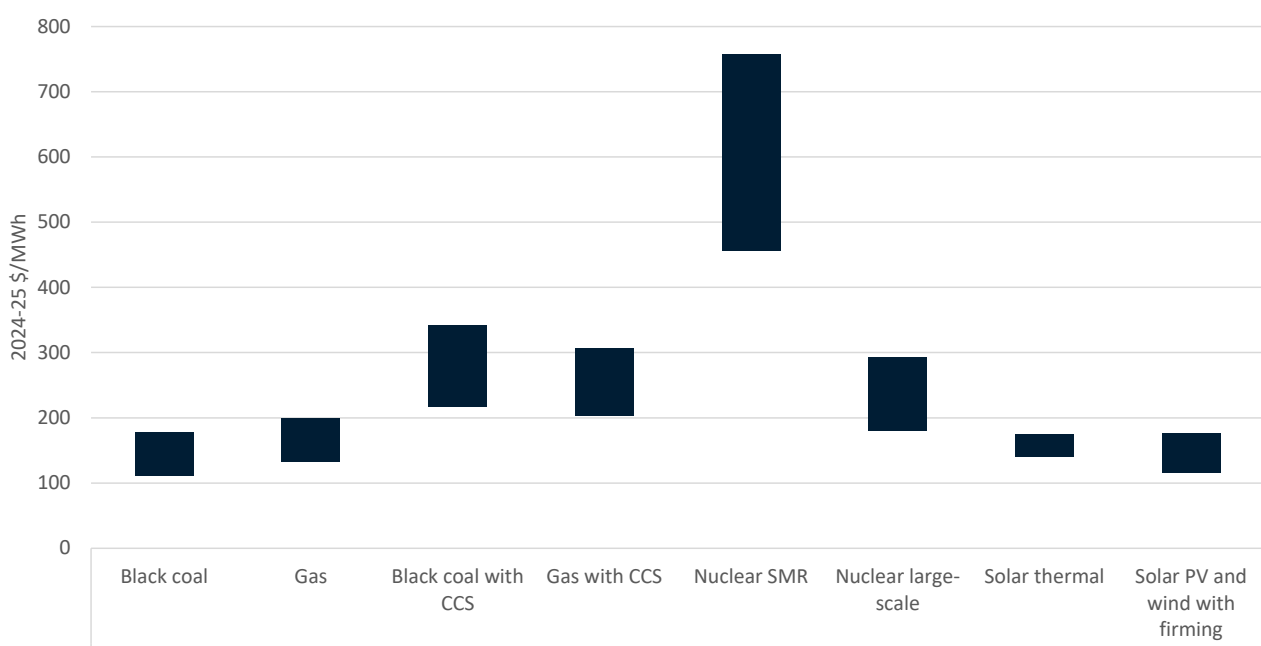


Figure 1 Levelised cost of baseload energy by technology for 2024 (CSIRO, 2025c)

The varying value of electricity is clearly reflected in the dramatic rise and fall in electricity prices in the NEM wholesale electricity market which can range from a (regulated) minimum of minus \$1,000 per MWh to a (regulated) maximum of \$23,200 per MWh with an average price of around \$96 per MWh (from 1 July 2026).

There has been rapid expansion of variable output renewable energy generation such as wind and solar power. This has increased the prevalence of generation supply exceeding demand with

consequent curtailment or ‘spilling’ of solar and wind generation. The curtailment of available ‘free’ energy, combined with the incidence of energy generation constraints, highlights that the primary emerging issue is less about ensuring sufficiency of energy generation and more about matching supply and demand. For this reason, energy flexibility to address energy constraints has risen to prominence. This is reflected in the supply side through the rapid growth of large-scale batteries.

This mismatch between supply and demand is equally important at the customer scale on the demand side. This is why it is proposed that FlexCost focusses on a set of specific periods of analysis that approximate to particular supply system roles (or effectively a set of market segments). While such periods are most prominent when available supply is insufficient to meet demand, they can also occur when available generation exceeds demand or network capacity, leading to curtailment, low prices, or negative prices.

It is proposed that FlexCost initially focusses on the ‘shorter’ periods of analysis with most constrained electricity supply and the potential for demand-side resources to provide relatively low cost ‘constrained period energy’ to address these deficits. This ‘shorter’ period of analysis is an ‘acute constraint’ covering the highest electricity price periods (50 hours per annum- see Table 1). Another proposed period of analysis is the ‘broad constraint’ period (500 hours or 6% of the total number of hours in the year), which approximates to what a future long-term gas role could be.

Additionally, it is proposed that two other periods of analysis will be investigated for use in the FlexCost report in order to support comparability with GenCost: a ‘daily evening peak’ period (around 1,825 hours, or 20.8% of the year) and a potential ‘bulk period’ (of 7,900 or around 90% of the year). Evaluating these longer periods of analysis allows the FlexCost framework to consider alternative demand-side technologies that operate on extended timescales, more comparable to less flexible baseload generation like coal-fired power stations rather than just fast-start gas-powered generation.

It is proposed that FlexCost will initially concentrate on energy during the short duration periods of analysis which approximates to occasional constrained, high unit cost, and potentially medium duration demand periods, the ‘broad constraint’ and the ‘daily evening peak’ demand, rather than addressing the cost of ‘bulk energy’ or continuous ‘baseload’ energy.

Therefore, the proposed measurement unit for estimating the levelised cost of demand side resources is $\$/\text{MWh}_{\text{PoA}}$ of coincident energy, where the energy unit of MWh_{PoA} is used (rather than power capacity MW) in order to align cost metrics with the levelised cost of electricity (LCOE) unit from the supply-side used in GenCost. The qualifier ‘PoA’ refers to the specific period of analysis such as an ‘acute constraint’ period which could include the top 50 most constrained hours or a period of analysis such as the ‘broad constraint’ or the ‘daily evening peak’.

Table 1 Potential Periods of Analysis for FlexCost

Period of Analysis-Name	Acute constraint	Broad constraint	Daily evening peak	Bulk energy
Period of Analysis-Hours per year	50	500	1,825	7,900
Percentage of total hours in a year	0.6%	6%	20.8%	90%
How is it determined?	Highest value periods: periods when demand and supply gap is greatest and highest price (above defined thresholds)	Potential long term gas role (future needs of the system) (AEMO, 2026).	Approximately 5 hours each night between 4pm and 9pm About 20% of the year, consistent with GenCost gas peaking plant role (CSIRO, 2025c).	90% of the year to match maximum availability of supply-side technology.
Can demand side technologies contribute? How many?	Yes. Many. Some already operating in emergency reserve roles.	Yes. Many. Particularly VPP and V2G.	Especially, residential heating and cooling loads e.g. improved energy efficiency, pre-heating, pre-cooling, flexible loads, pools, EV charging etc	As for renewable energy and storage, a combination of energy efficiency and demand flexibility would be required.
How do we know when demand-side resource has to be available (and can change its behaviour relative to BAU behaviour)?	Based on historical market data	Potentially use existing CSIRO modelling results	4pm to 9pm	Would require a mix of measures to be available nearly all the time.
Is there a comparable supply-side technology that could be costed	Potentially gas and large batteries	Peaking gas	Peaking gas or long duration storage.	A wide range of baseload technologies or portfolios of technologies.
Is there a comparable futures market contract for electricity supply in this category	No	No	Yes, 'peaking' contract (ASX, 2025)	Yes, approximates to flat 'baseload contract' (ASX, 2025).

It should be noted that adopting specific periods of analysis (such as 50 or 500 hours per year) and a standardised levelised cost metric involves inherent simplification. On the supply-side, peaking generators, are relatively uniform in design and operation and can in principle run continuously as long as fuel is supplied. By contrast, demand-side flexibility encompasses a very wide range of technologies, sectors and measures, that are defined by a complex set of parameters (e.g. number of operations, duration of operations, recharge period, temperature impacts) and behavioural constraints. Consequently, the levelised metrics presented in FlexCost should be interpreted as communication tools designed to enable high-level policy comparisons. Detailed power system analysis and operational dispatch modelling would require adherence to the full, more complex technical characteristics of each resource.

For reasons of enhancing both reliability and affordability, additional energy resources should be targeted to those time periods under greatest constraint and of highest value. Accordingly, estimating the costs of demand-side resources should focus on their costs to address these constrained periods in particular. The next section considers how such periods of energy deficit should be identified and defined.

2.2 Defining constrained energy periods

A key question for FlexCost is how to define the constrained energy periods. One option would be to estimate the cost based on the energy that the demand-side resource provides throughout the whole year. However, it would be counter-intuitive and counter-productive to treat all times as equally valuable when there are clearly periods when the system is constrained and others when it is relatively unconstrained and indeed has an overabundance of energy. A more useful definition of constrained energy periods would be to identify those periods where there is a significant risk of electricity demand exceeding supply capacity. It is also crucial to distinguish between ‘the need’, that is, the ‘constrained energy deficit’ in a given (constrained) period of analysis and resource to satisfy that need, that is the energy available to address constraints in that period or ‘available coincident energy’ (ACE).

The electricity system must manage within many constraints relating to voltage, current, frequency, power factor, and so on, and over various timeframes from milliseconds to years. For this analysis, we are focussed on the ‘big picture’ constraints related to energy and capacity as these constraints drive the biggest costs and impacts within the energy sector. In terms of these energy constraints, there are three key overlapping dimensions:

1. **Generation and network sectors.**

The generation and network sectors are the two biggest contributors to electricity bills. In considering constrained energy periods, both sectors are important and each is considered in turn in sections 2.3 and 2.4 below.

2. **Physical limits and costs (or prices).**

Although physical limits set the ultimate constraints on how much electricity can be supplied, these physical limits are also subject to and defined by costs. Constraints can often be overcome at a cost, through acquiring more capacity (on the supply-side or demand-side) and physical limits are often signalled by prices, as in the wholesale electricity generation market. On the other hand, it should be recognised that supply availability, constraints, and prices, can also be influenced by non-physical limits, including the exercise of market power.

3. **Peak capacity and available capacity.**

Sometimes constraints are set not by the physical capacity of generation or network infrastructure, but by how much of it is available for deployment at a given time. This is particularly true for generation, which may be constrained by breakdowns or maintenance, how much fuel (e.g. coal or gas) or resource (wind, solar or water storage for hydroelectricity) is available, the exercise of market power, or by network limits between generators and customers. Networks are not as constrained as fuel or renewable resources

limits but are also constrained by faults, outages, natural disasters and maintenance. So, although peak demand can often drive network constraints, constrained energy periods are not necessarily always aligned with peak demand.

It is also important to recognise that while there are regular patterns in both supply and demand, there is also a large degree of unpredictability, so it is impossible to predict either with certainty. Although we know that the solar does not generate at night and we know that peak demand tends to occur in the early evening on a weekday in summer or winter, we cannot however predict with accuracy on which day peak demand will occur, or on which day several large power stations will experience outages simultaneously.

On the other hand, high precision in predicting the timing of energy constraints may not be necessary for demand-side resource to be useful, since many demand flexibility resources can be accessed or dispatched at relatively short notice. Conversely, as many energy efficiency resources are correlated with demand and cover many hours, these resources may also be useful.

Constrained energy periods are typically characterised by the level of available supply compared to demand (MW, or % of capacity), their timing and their duration (hours, or % of the year), so constrained energy periods could be defined by MW of capacity, specific time and *either* hours per year *or* by percentage of the year. Given that every case has a different level of demand and supply but operates according to the same 24 hours/365 days timeframe, defining constrained energy periods by the duration in hours is likely to provide a more standardised and harmonised metric.

The following two sections consider both the generation and network sectors to identify and characterise constrained energy periods in each sector.

2.3 Electricity generation market constraints

As noted above, flexibility is most needed when and where there is a considerable mismatch between available supply capability and regional demand. This mismatch increases when electricity demand is high, the electricity supply market is tight, slow to respond, or operating close to technical and economic limits. Forecasting demand accurately has long been a challenging task, because demand is dependent on many factors, especially weather, which is highly variable and unpredictable. Forecasting supply has also become more complex in recent decades due to the rising prevalence of wind and solar, which are also weather dependent. The increasing age of the existing fleet of fossil fuel generators has also increased the challenges of supply reliability and forecasting.

Notwithstanding these challenges, past experience remains our best guide for forecasting supply and demand and therefore for forecasting the gap between demand and supply. We have two relatively accessible historical data sources for identifying constrained energy periods. The first is to use net customer energy demand data (that is, after netting out the impact of customer generation, mainly rooftop solar PV). This is a reasonable proxy as long as customer generation or storage discharge is not correlated with either time or demand. The second data source is to use the wholesale spot price. Both options are discussed below. While we propose to use historical constraint data and extrapolate current trends data for forecasting energy constraints, we recognise that more sophisticated statistical approaches should be considered in the future.

It is proposed that the inaugural FlexCost report considers both expected net supply (expected supply minus expected demand), and wholesale spot market prices as useful proxies for defining electricity energy constraints.

Demand as a proxy for constrained energy periods

Figure 2 illustrates electricity demand (net of rooftop solar output) in the National Electricity Market (NEM) across all hours of 2023 (24 hours per day, over 365 days). This figure exhibits the well-known intra-day demand profile and the effect of seasonality, where winter and late summer evening demands reach around 27-29 GW, while spring and autumn evening demands are significantly lower.

The wide band of high demand (in yellow) between roughly 14:00 and 21:00, specifically from June to August and again in late December, shows periods when dispatchable supply must ramp up quickly and operate in scarcity conditions. These are the hours when flexibility from demand-response, storage discharge, or fast-start peaking generation (typically open cycle gas generation) is most valuable for maintaining adequacy and limiting extreme wholesale prices.

In contrast, the midday band (around 10:00 - 15:00), particularly in spring and autumn has considerably lower demand (shown in blue), once rooftop PV is accounted for, signalling opportunities for flexibility via load shifting and storage charging to absorb surplus energy.

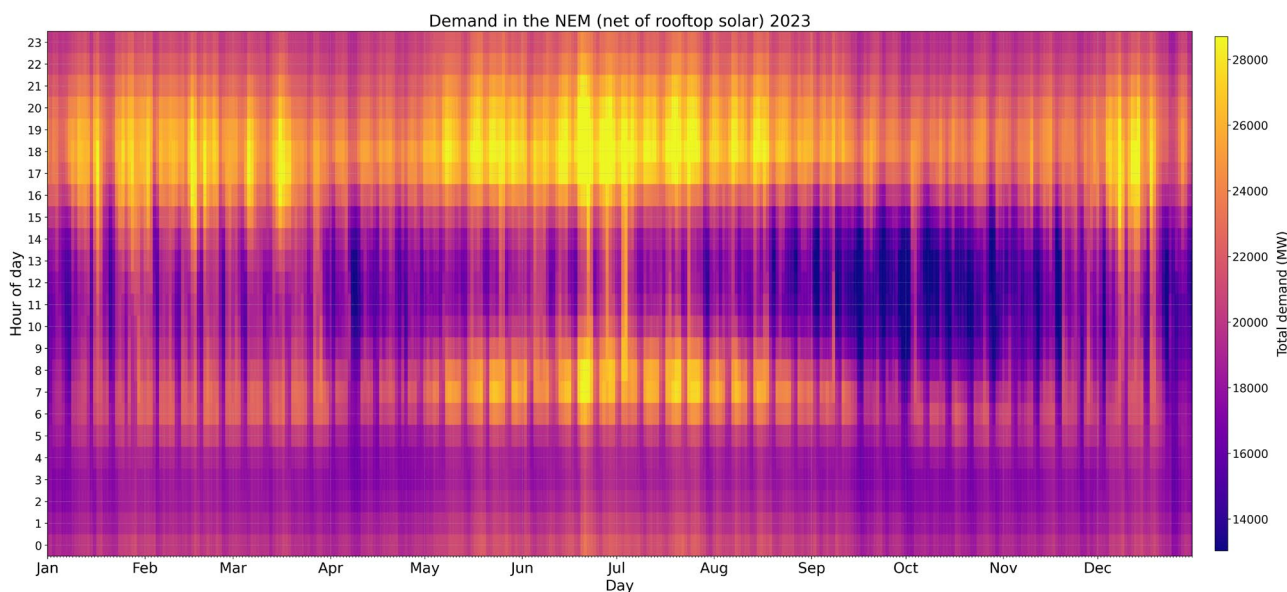


Figure 2 Demand in the NEM, 2023 (hours, MW)

Figure 3 presents data similar to Figure 2, but instead of presenting all 8,760 hours in the year 2023, it shows only the 50 hours with highest demand. This heatmap of the top 50 NEM total-demand hours (net of rooftop solar output) isolates the highest-demand days and times, when flexibility is most critical under energy market constraints. The highest-ranked events cluster in late June and July, almost all between about 16:00 and 20:00, consistent with winter evening peaks driven by building heating load and reduced solar contribution. A smaller group of high-demand events appears in February and March, again in the late afternoon to early evening, reflecting summer heatwaves and air-conditioning load. There is also a limited number of highly

ranked events around 6:00 - 8:00 am on June mornings, pointing to cold winter mornings where demand rises before solar ramps up.

These three clusters show that the requirement for flexibility is concentrated in short seasonal windows and within a few critical hours of the day. This provides a good indication of constrained energy periods and therefore for the desirable timing, sizing and utilisation of demand-side resources. Of course, such historical data also reflects variable factors such as weather and consumer demand, so it cannot be used as a precise guide to future constraints but can be used to provide an indication of constrained energy periods at different times and seasons.

Note that the choice of 50 top hours here is arbitrary and was selected for illustrative purposes. The top 100 or 200 hours could just as easily have been chosen and would have illustrated similar patterns, just as the 8,760 hours in Figure 2 did. The choice of how many hours to include in the definition of constrained energy periods is discussed further below (see Table 2).

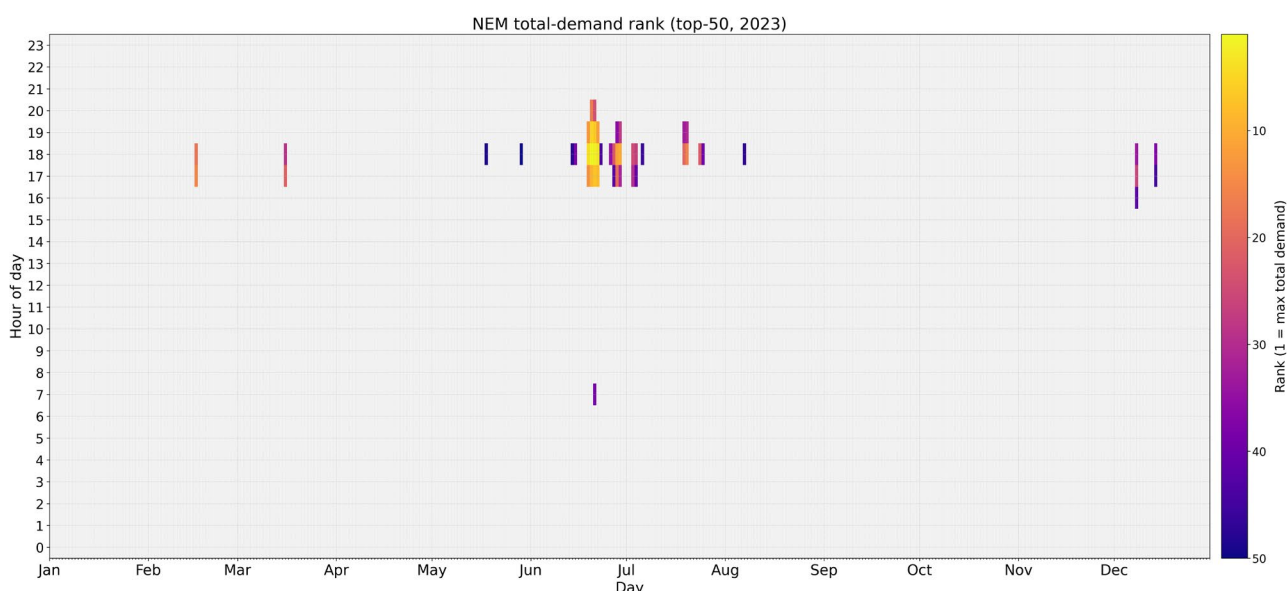


Figure 3 Top 50 highest demand hours in the NEM, 2023

The Load Duration Curve shown in Figure 4 presents the same data in another way. This load duration curve arranges demand in the NEM for all 8,760 hours in the year in order from highest demand to lowest demand. This allows the observer to read off how many hours of the year the demand exceeds any given level of demand. The inset in the blue box focusses on the top 50 hours of demand, showing that these top hours account for the top 3,000MW or about 9% of demand at its peak.

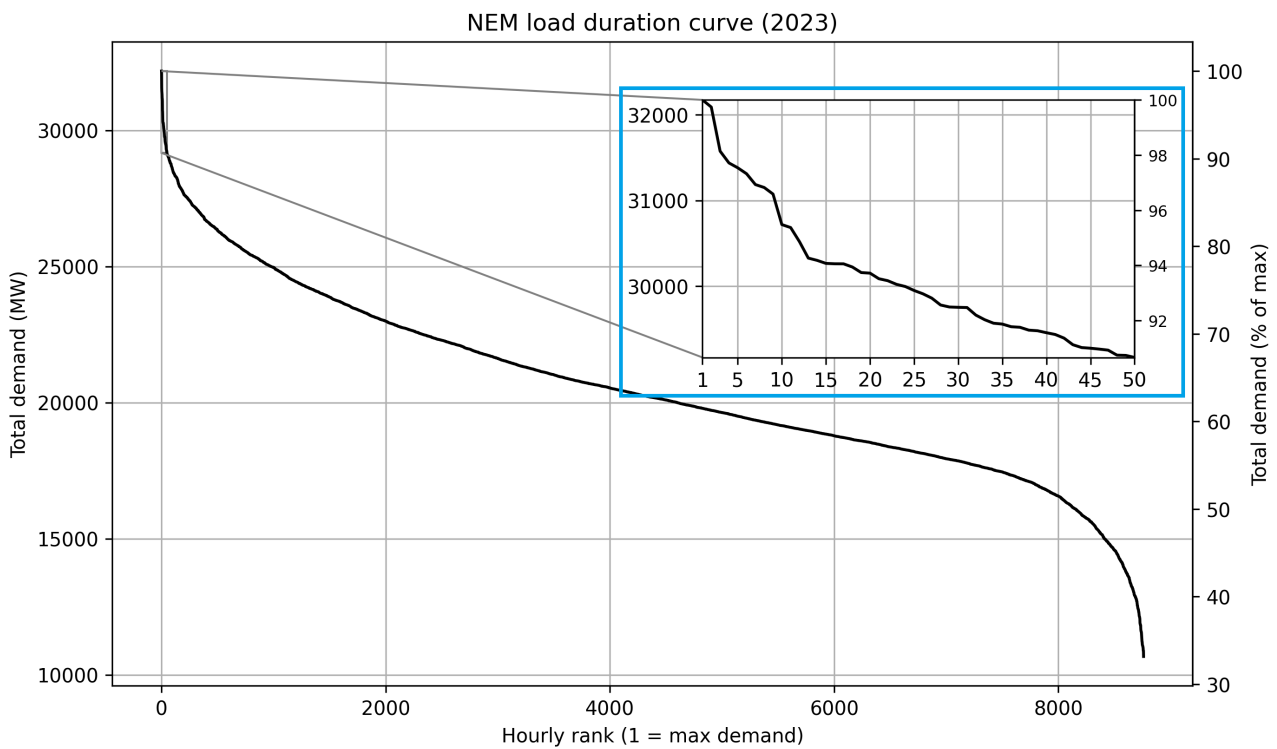


Figure 4 NEM Load Duration Curve (2023)

Prices as a proxy for constrained energy period

Although electricity demand and in particular peak demand is not a precise indicator for generation-driven constrained energy in the wholesale market, it is a useful proxy. Another useful and arguably more relevant metric is the pool price, as this more directly signals relative scarcity in the electricity generation market.

Where Figure 2 illustrates demand in the NEM in 2023, Figure 5 presents a similar heatmap analysis of constrained energy periods based on spot prices in the NEM in the region of NSW for 2023. In this case, the region of NSW has been chosen because prices can vary significantly from state to state, particularly at times of high prices or constrained energy periods. Figure 5 shows how these NEM-wide demand patterns translate into state-level market price signals, which are the most direct indicator of when flexibility has high economic value.

As shown, prices in NSW span from around negative \$100/MWh up to about plus \$20,000/MWh, but most hours lie in the \$0-\$300/MWh range. This indicates that the supply-demand constraint is concentrated in specific windows rather than being persistent. Prices are relatively flat and moderate overnight, become more volatile from the morning ramp, and are most frequently elevated in the late afternoon and evening. In autumn and winter, there is a wide band of light green to yellow colours between about 16:00 and 20:00, with occasional orange and red spikes, consistent with winter evening scarcity conditions and tighter dispatchable supply margins. These windows indicate periods when flexibility from storage discharge and demand response is likely to be most valuable, because it can directly reduce reliance on high-cost marginal units and decrease high price events.

In contrast, from late winter into spring and early summer the heatmap shows a horizontal band of frequent zero or negative prices between about 7:00 and 15:00. This pattern aligns with the lower net-demand hours in the NEM demand heatmap and is consistent with high solar availability

combined with limited demand-side absorption. These hours highlight the value of flexibility in the form of load shifting or storage charging that can convert low or negative-price periods into useful energy while also reducing oversupply conditions. The scattered high-price spikes outside the main winter and summer peak windows might be due to local outages, transmission limits or bidding behaviour and are not tightly coupled to the highest total-demand hours.

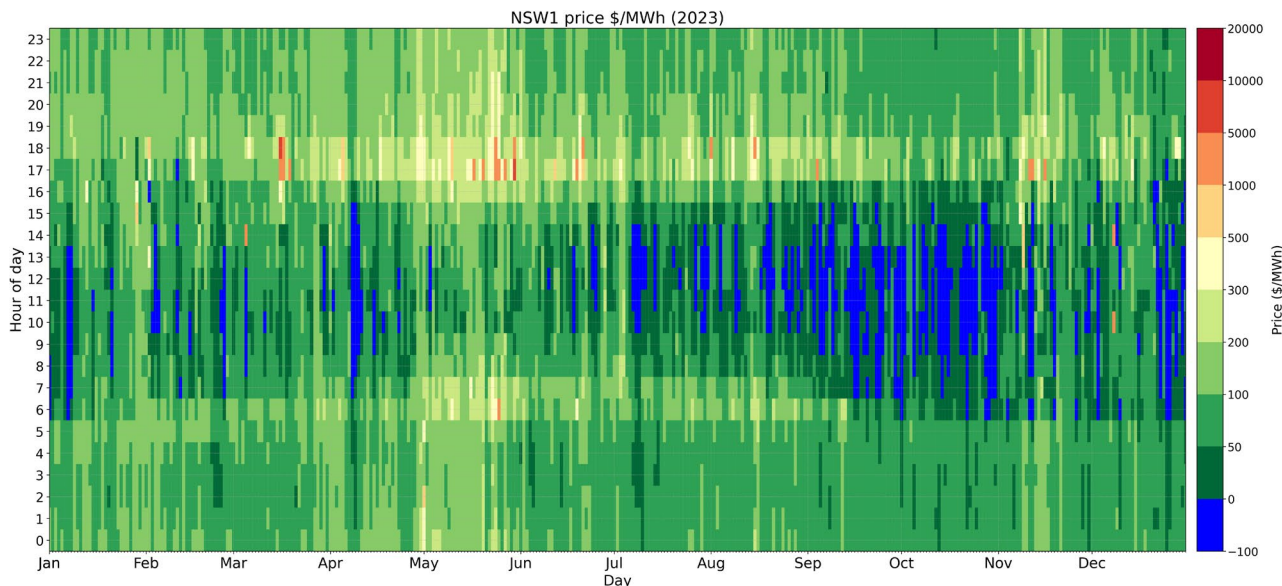


Figure 5 Prices in the NEM (for NSW region, 2023)

Figure 6 presents the corresponding NEM price data for the region of Queensland in 2023. It is apparent that apart from a higher prevalence of negative price periods in Queensland, there are many similarities to NSW.

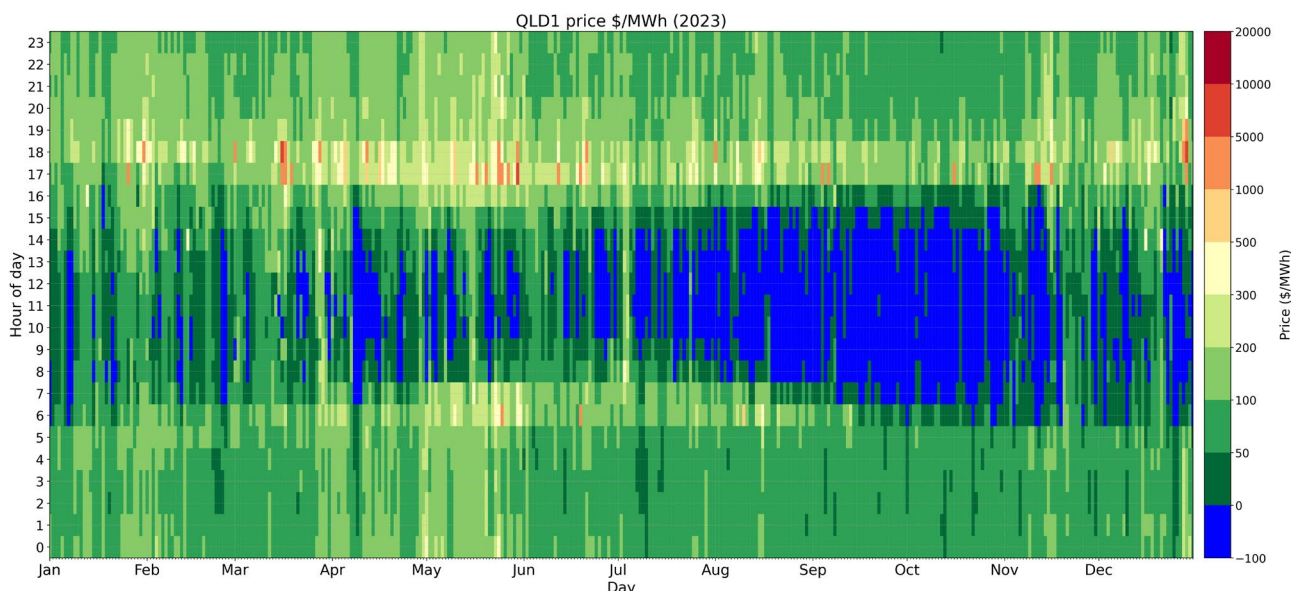


Figure 6 Prices in the NEM (for Queensland region 2023).

The NSW price duration curve for 2023 (and 2024) ranks all hourly prices from highest to lowest (Figure 7). Consistent with the heatmap, the curve is steep in the upper tail, indicating that a small number of extreme hours account for a large share of the maximum prices. Comparing 2023 with 2024, the middle of the duration curve is similar, suggesting broadly comparable normal operating conditions. The main differences lie in the tails. At the high-price end, the top 50 hours inset

subplot (blue-bordered box) shows that 2024 experienced both higher maxima and a thicker scarcity tail. It shows that scarcity events were both more severe and more frequent. This indicates that flexibility from additional demand-side resources would have had higher value in 2024, particularly if it was targeted at these higher price hours.

From a valuation perspective, the top-ranked price hours (for example, the top 50 hours in the Figure 7 price duration curve) are prime candidates for demand-side resources. These hours represent periods when the regional supply-demand balance is most constrained, so an incremental unit of battery discharge, demand response, energy efficiency or other demand-side (or supply-side) resources has the greatest ability to ameliorate scarcity events and capture market value.

These most constrained hours are state- or region-specific, because scarcity and surplus conditions are ultimately defined at the regional level by the local generation mix, demand shape, the availability of dispatchable capacity, interconnector constraints and weather. In contrast, the lowest ranked, least constrained hours (including zero and negative price periods) represent the best opportunities for charging batteries or load shifting to absorb surplus energy and avoid curtailment of surplus generation.

Although the exact extreme hours may not repeat from year to year due to weather, outages, and bidding behaviour, they continue to occur within a relatively stable set of structural conditions (winter and summer early evenings for the highest prices, and sunny autumn and spring middays for the lowest). Selecting the top (and bottom) N hours each year provides a robust basis for identifying where and when flexibility is most valuable, and for sizing and benchmarking flexible resources against the conditions that matter most for market events.

It must be noted that the top N hours are region-specific because scarcity and oversupply conditions are defined at the regional level by the local generation mix, demand shape, and the availability of dispatchable capacity. For example, using 2023 data, the top 50 price-ranked hours align with different shares of maximum demand conditions across regions, ranging from roughly 70% to 95% (depending on the region).

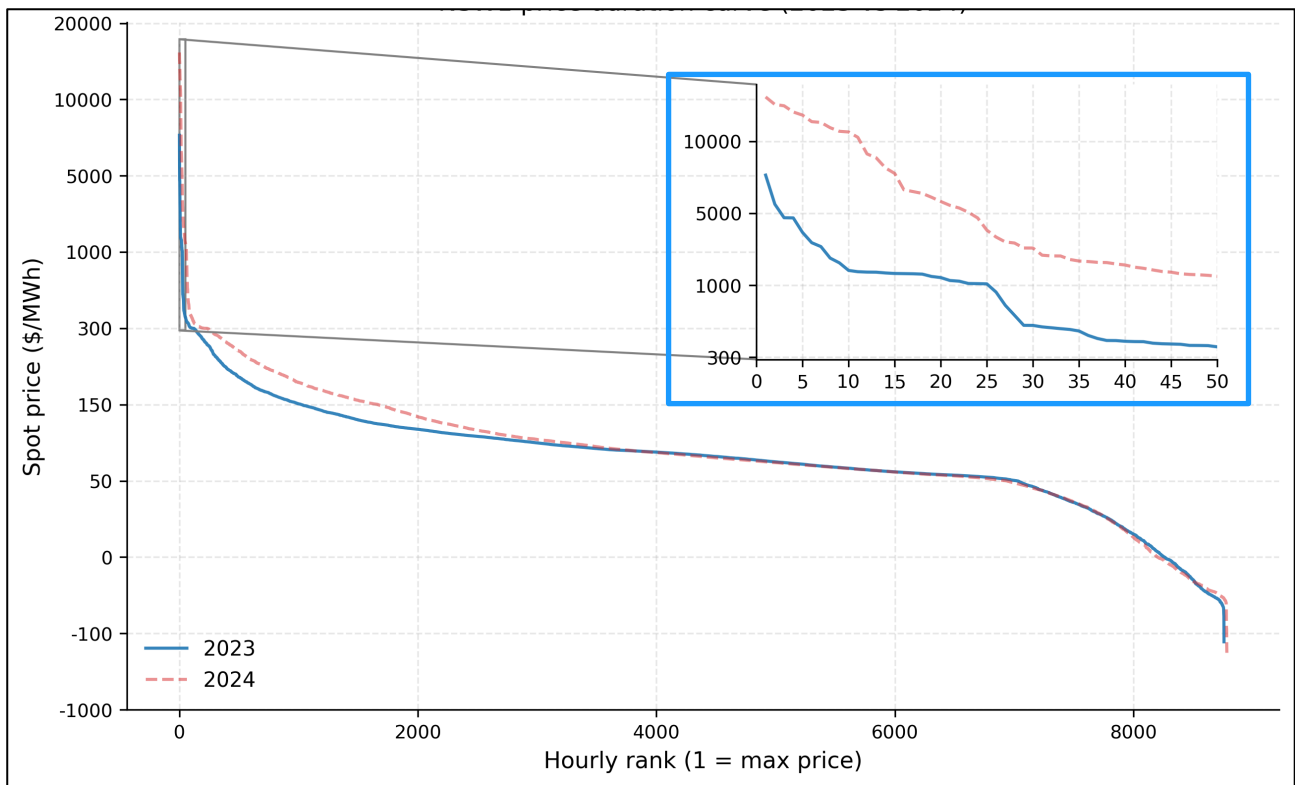


Figure 7 NSW Price Duration Curve (NSW 2023 vs 2024)

Defining standard periods of analysis.

Drawing on both the NEM Load Duration Curve in Figure 4 and the NSW Price Duration Curve in Figure 7, it is possible to compare the extent of energy constraint across different numbers of most constrained hours, based peak demand (in the NEM) and maximum prices (in this case in NSW).

Table 2 Top N hours in terms of total demand (NEM) and price (NSW), 2023.

Constrained period: Top (N) hours per year	% of the year	Sum of NEM demand across only top N hours (GW)	Sum of NEM demand across top N hours as % of peak demand	Price range within top N hours (\$/MWh, NSW Region)
10	0.1%	1,453	4.5%	\$1,826 – \$7,652
20	0.2%	2,020	6.3%	\$1,430 – \$7,652
50	0.6%	3,003	9.3%	\$402 – \$7,652
100	1.1%	3,614	11%	\$303 – \$7,652
200	2.3%	4,511	14%	\$279 – \$7,652
500	5.7%	5,841	18%	\$204 – \$7,652

To select the optimum numbers of hours to define Periods of Analysis requires balancing competing criteria. On the one hand, the smaller the number of hours selected, the more this represents periods of material constraint. On the other hand, the larger the number of hours, the greater the potential total value that can be captured from periods addressed.

AEMC has forecast average *wholesale* electricity prices at 12.5 cents/kWh (\$125/MWh) and *retail* residential electricity prices for 2025/26 at 37 cents/kWh (\$370/MWh) (AEMC, 2025). It can be argued that electricity prices would need to be above these levels to be reasonably considered as constrained. On this basis, the top 10, 20 and 50 hours would all fall within this criterion. In order to maximise the value captured from high pool price periods, it would be desirable to choose the largest of these options, that is the top 50 hours. This option of the top 50 hours corresponds to the top 9.3% of peak demand. Given that the sum of peak demand across the five NEM states (non-coincident) is forecast to grow by about 21% between 2026 and 2036 (as shown in Figure 9), addressing 9.3% of the highest demand could amount to about four years of forecast growth in demand. Consequently, a four-year operational horizon would seem to represent a pragmatic timeframe for strategic grid planning purposes.

As with many conventions, there is no ‘right’ answer for the right period to choose for adopting a standard period of analysis. A figure around the top 50 hours (or say, 44 hours which represents 0.5% of the year) may seem a reasonably useful convention. CSIRO has consult with key experts in selecting the proposed Periods of Analysis and will seek to develop a consensus over a preferred standard for the number of energy hours per year or preferred set of periods of analysis.

Note that the cost of demand flexibility or energy efficiency for the period of analysis (say, top 50 most energy constrained hours) will be different to the cost of demand energy or energy efficiency anytime, that is, not just in the constrained period (see Table 1 for other possible periods of analysis).

Expected Unserved Energy as an indicator of constrained energy

Another consideration in selecting periods of analysis is whether constrained periods are likely to impact on supply reliability.

In the NEM, Unserved Energy (USE) represents the amount of customer demand that cannot be supplied within a region of the NEM due to a shortage of generation, demand-side resources, or interconnector capacity. USE generally does not include customer interruptions arising from local transmission or distribution outages. AEMO calculates Expected Unserved Energy USE to forecast supply interruptions consumers may experience due to generation and interconnection inadequacy.

As illustrated in Figure 8, recent AEMO analysis suggests that based on currently ‘Committed’ and ‘Anticipated’ projects, there are significant potential risks to reliability between 2028 and 2033 in South Australia, Victoria, NSW and Queensland. These forecasts indicates that there are energy deficit periods and a need for additional resources (demand-side and/or supply-side) over this period.

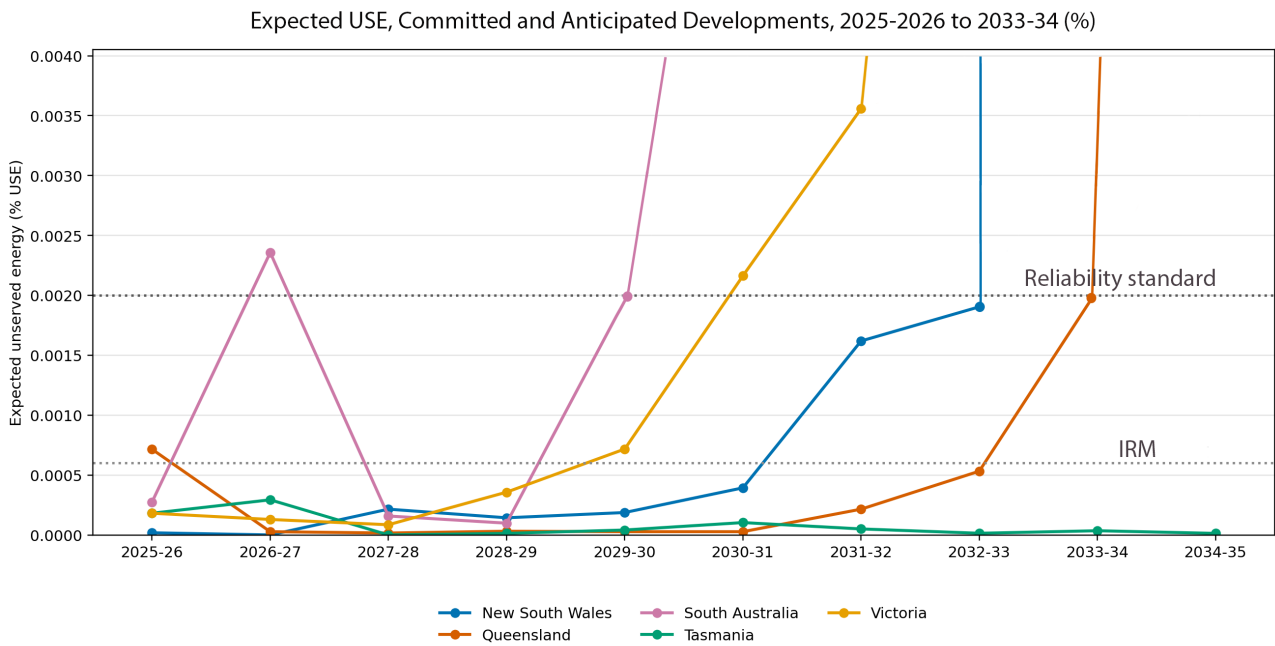


Figure 8 Expected Unserved Energy (% USE) 2026-2035 (AEMO, 2025a).

A further consideration is long term growth in electricity consumption as a driver of constrained energy. Given the expected growth of population, the economy and electrification, both peak and total electricity demand are expected to raise rapidly, even after allowing for energy efficiency improvements and rooftop PV. This raises the question of the degree to which increased reliance on demand-side resources could reduce cost, social and environmental impacts associated with expected demand growth.

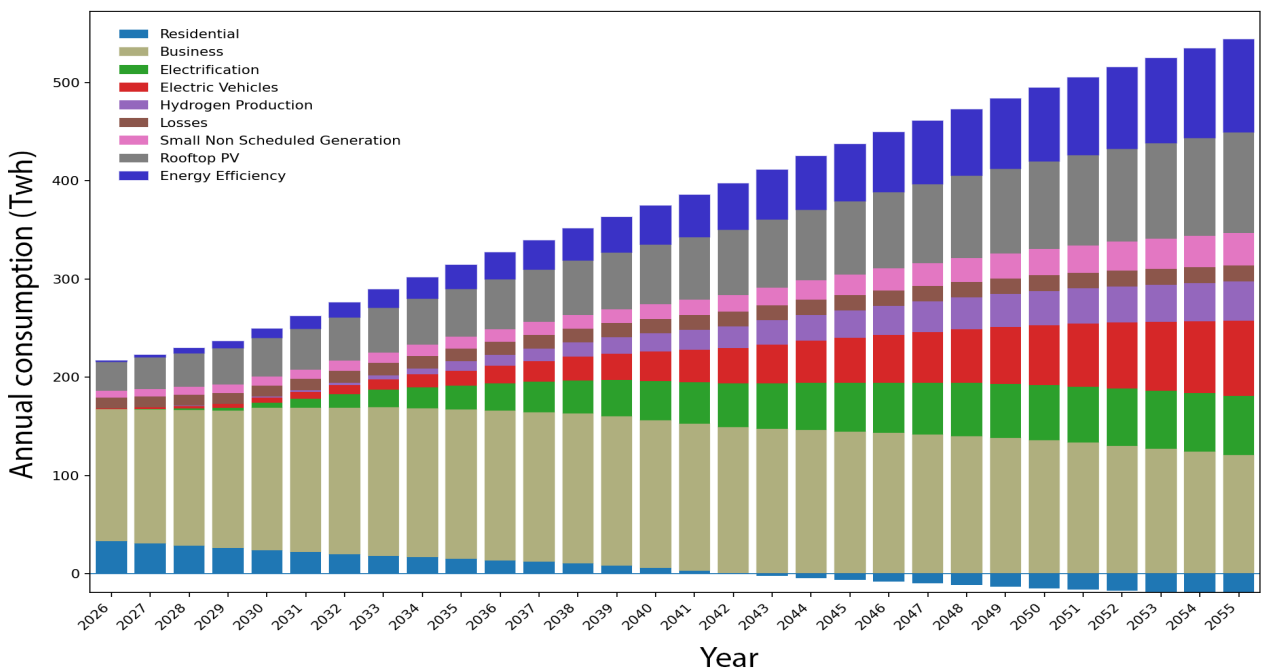


Figure 9 Forecast energy efficiency consumption in the NEM: Step Change 2026-2055 (AEMO, Data Portal, 2025)

2.4 Locational and network constraints

In identifying energy constraints, both in the generation energy market and networks, location is crucial. As noted above, the timing of energy constraints varies significantly between NEM states due to interstate transmission limitations. At the more local level, distribution networks currently represent about three quarters of the network costs and distribution constraints are intrinsically locational. These constraints should not be overlooked.

With many coal-fired power stations reaching the end of their economic lives, the focus of the electricity market over the past decade has been on new investment in large scale generation and storage capacity, and in new transmission required to connect these supply-side resources to the main grid. Investment in distribution networks has received comparatively less attention. The increase in demand-side resources, including improved end use energy efficiency and the massive increase in rooftop solar PV, has virtually eliminated growth in net peak demand on the main grid in the NEM over the past decade.

These trends are reflected in Figure 10 which shows more than 80% growth in the distribution and transmission Regulatory Asset Base (RAB) between 2006 and 2015, followed by less than 10% growth in the following decade. Similarly, Figure 11 shows that following 44% growth between 2006 and 2015, distribution network capacity has essentially flatlined since then. If recent trends were to continue, then it may be reasonable to neglect the potential impact of networks on energy constraints and costs. However, it is likely these trends will not continue, as discussed below.

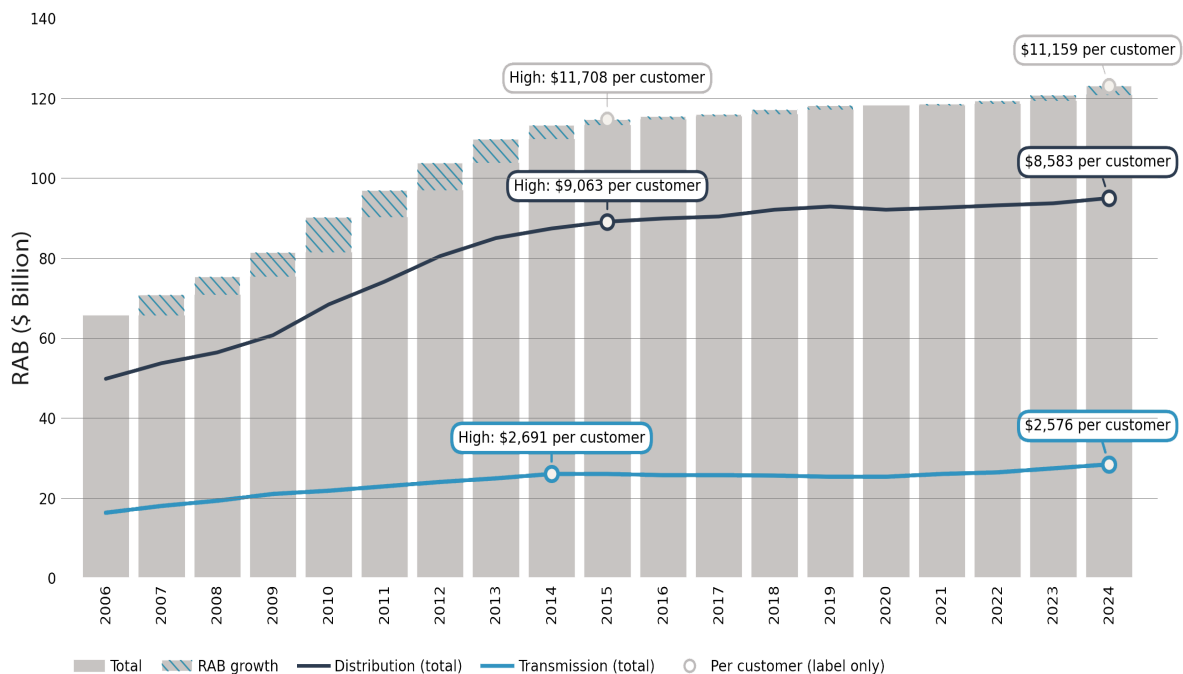


Figure 10 Growth in Distribution Network Regulatory Asset Base, 2006 to 2024 (AER, 2025).

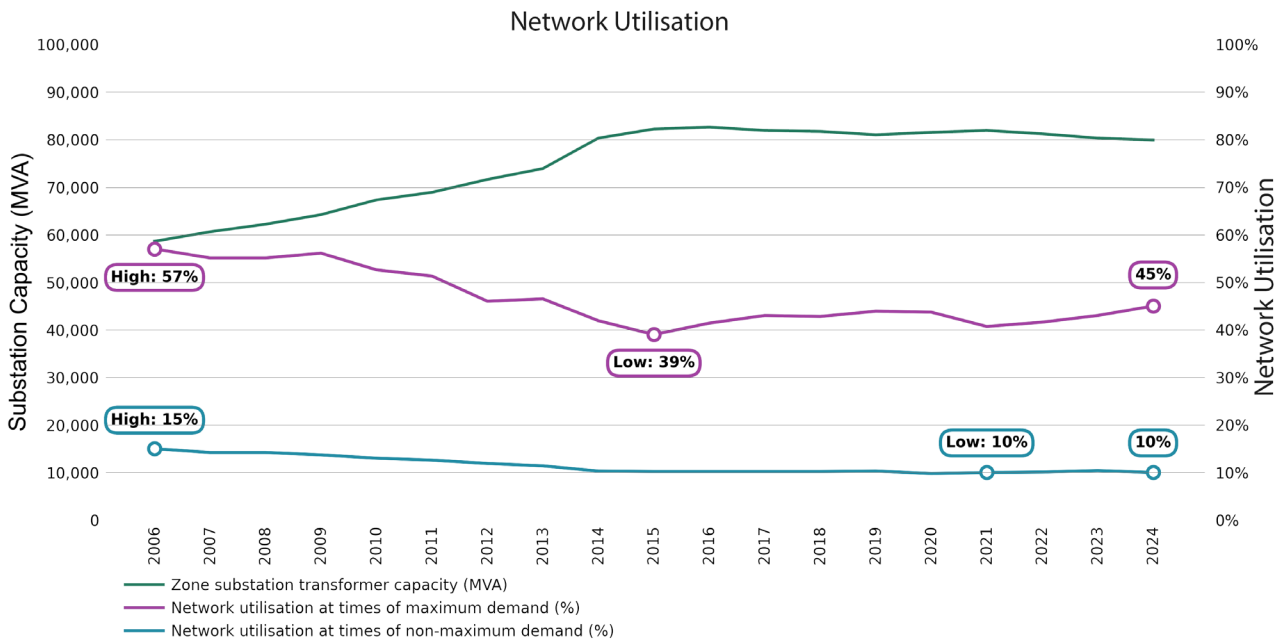


Figure 11 Network Zone Substation Capacity and Utilisation Factor 2006 to 2024 (AER, 2025).

Network costs can contribute at least as much to electricity constraints and costs as the generation market. As shown in Figure 12, over the next decade electricity network charges are expected to comprise a larger share of electricity bills than generation costs (as represented by wholesale prices).

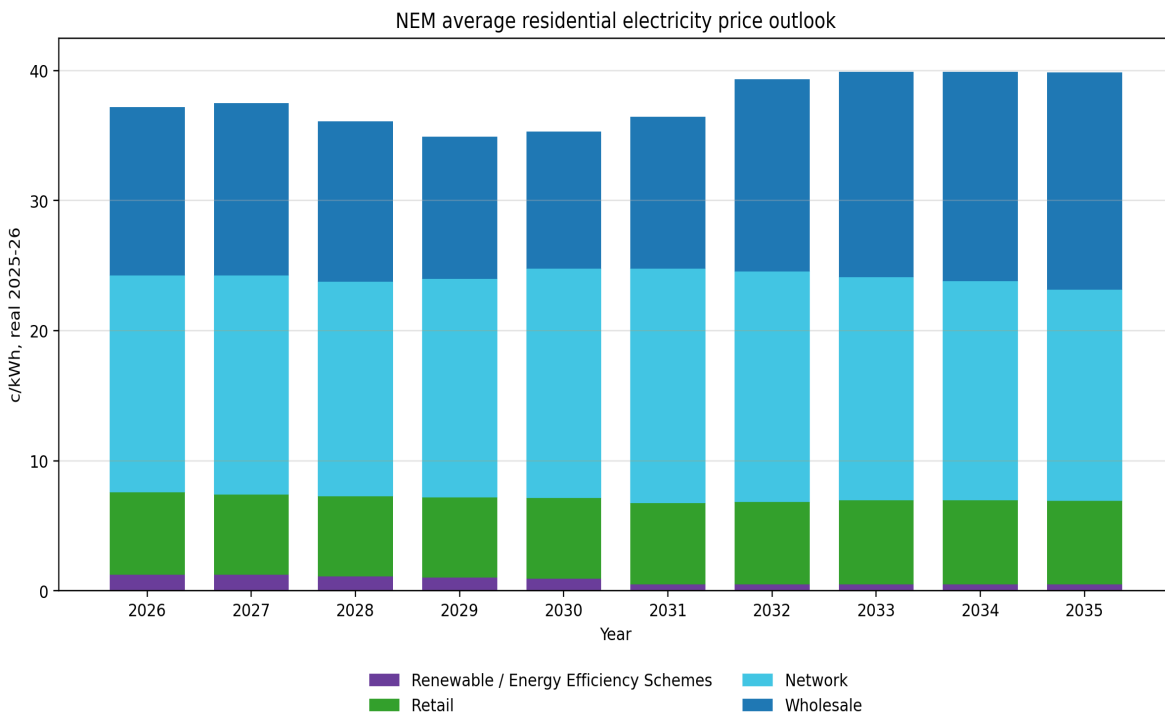


Figure 12 NEM average residential electricity price outlook and sectoral shares: 2026-2035 (AEMC, 2025)

Figure 13 highlights key reasons for the potential renewed growth in network infrastructure driven by projected acceleration in adoption of electric vehicles (in purple) and other electrification (in orange).

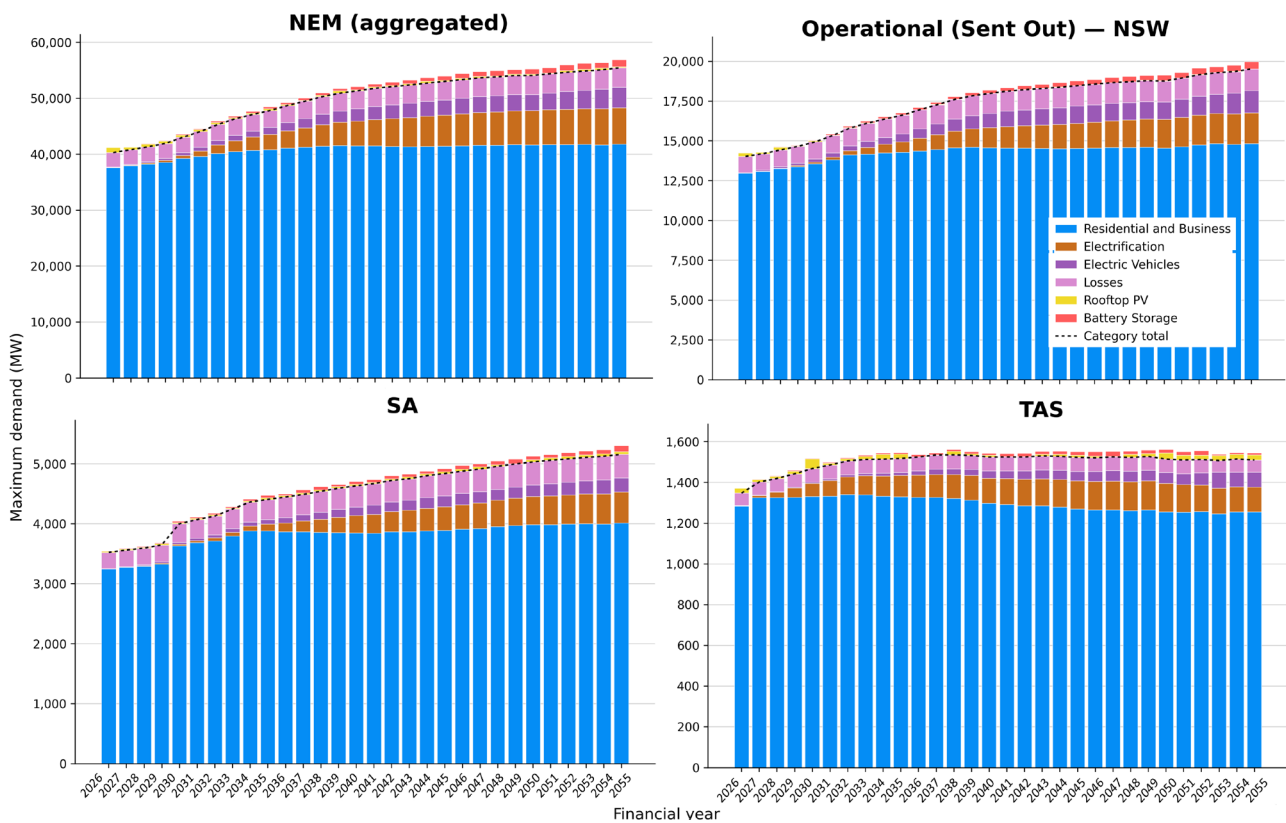


Figure 13 Forecast Maximum Demand in Regional and NEM Sum (sum of maximum demand in five states) 2026 - 2055 (AEMO, 2025d)².

Available network capacity varies greatly by time and place. In some areas, there may be no binding network constraint for a decade or more, while in others the network constraint may be acute and represent significantly higher risks for unserved energy (and hence potential costs) than the most constrained periods in the generation energy market.

In order for demand-side resources to assist in addressing network constraints, they must be identified and assessed according to local constraints and processes. These processes include the Transmission and Distribution Annual Planning Reports (TAPRs and DAPRs) and the Regulatory Investment Tests (RIT-T and RIT-D).

These network planning and assessment processes need to consider numerous factors including, existing capacity and expected demand growth rates, reliability criteria, value of customer reliability, investment lead time, demand-side resource development lead time, and other parameters.

While the importance of network constraints in shaping future electricity costs is undeniable, the complexity and data requirements for defining these constraints is significant. For this reason, it is proposed that the focus for defining energy constraints in the first version of FlexCost is on generation market data, rather than on network conditions. Network constraints may potentially be considered in future iterations of the FlexCost Report.

² Note: A considerable share of behind-the-meter PV generation and storage discharge is not directly visible to the network, instead appearing as reduced electricity consumption.

3 Selecting Demand-side Resources

Key points

It is proposed that FlexCost method should:

- Apply explicit criteria in selecting which demand-side technologies to include in the first version of the FlexCost Report. Suggested inclusion criteria discussed in the method report: potential impact, materiality, comparability, actionability and data availability.
- Focus in the first version of the FlexCost Report on technology-based rather than behaviour-based demand-side measures.
- Focus in the first version of the FlexCost Report on incentive-based rather than pricing-based instruments.
- Focus on ‘achievable potential’, which recognises practical implementation limits, in assessing the cost of demand-side resources, while also considering technical and economic potential, where relevant or appropriate.
- Make clear that the unit cost of deploying demand resources can vary significantly depending on the level of uptake of these resources, and this cost/uptake relationship is critical to estimating demand-side resource costs.

3.1 Key concepts and definitions

This section discusses key concepts in choosing and defining demand-side resources, considering:

- which demand-side technologies and measures are in scope.
- which technical and cost parameters are reported for each technology.
- operating approaches and enabling arrangements.
- specifying time horizons for cost inputs (current values and forward projections) and associated assumptions.

It is important to have clearly defined and consistently applied terminology. The following is a description of some of the key terms and definitions for demand-side resources:

- **‘Technology’**: A hardware appliance or other equipment that uses, conserves or stores energy to provide a service to customers.
 - Examples: Water heater, air conditioner, battery, pool pump, refrigerator, building envelope, insulation, solar panels, etc.
- **‘Behaviour’**: How the technology is used by the customer and includes both ‘good’ and ‘bad’ behaviour.
 - Examples: setting the air conditioner thermostat to a higher temperature, shifting appliance use to off-peak periods, charging an EV overnight, reducing hot water use, pre-cooling a building before a peak period.
- **‘Measures’**: Changes in technology or how the technology is used.

- Examples: Replace air conditioner, improve maintenance, install motion sensors, acquire EV, switch battery to VPP
- **‘Instrument’**: Policy or program initiative taken by government, regulator or utility to stimulate adoption of measures.
 - Examples: Cash rebates, dynamic power pricing, appliance labelling, free energy audits, ban incandescent lights, binding target, tradeable certificate scheme, etc
- **‘Option’**: A practical initiative that leads to a change in how energy is used. *Options* apply an *instrument* to stimulate a *measure* **which leads to changes in behaviour and/or technology applied**

Examples:

 - Option A: A government offers a cash incentive (*instrument*) to encourage installation (*measure*) of a home battery (*technology*).
 - Option B: An energy regulator requires more cost reflective electricity utility pricing (*instrument*) and encourages installation of smart meters (*measure*) to change the patterns of demand (*behaviour*).

3.2 Choosing Demand Flexibility options

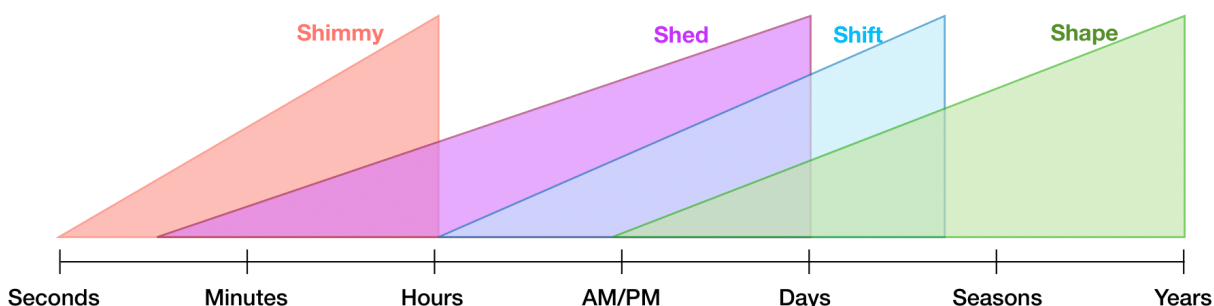
The FlexCost technology scope is defined using criteria analogous to those applied in GenCost for technology inclusion and exclusion, adapted to the demand-side context. The intent is not to catalogue every end-use or program variant, but to focus on a material and decision-relevant set of technologies for which costs and performance can be specified consistently to support comparability and downstream integration into planning and valuation studies. FlexCost Stage 1 is limited to residential and small business CER and therefore excludes large commercial and industrial demand response.

In the decision to include/exclude technologies within this review of methods, the timescale over which a service is provided to the grid has been considered. Demand flexibility³ can occur at different timescales from seconds to months, depending on the market mechanism or system requirement involved (Alstone et al., 2017):

1. ‘Shimmy’ refers to DR operating over very short timescales, typically used to provide frequency control and ancillary services (FCAS) that help with stability and security of the grid.

³ Demand flexibility is a dispatchable resource that can participate in wholesale energy and balancing markets, ancillary-services, capacity and network service markets. Demand Flexibility can also be procured via local flexibility platforms, retailer programs, and bilateral contracts. In these schemes, consumers are paid to decrease (or shift) their demand when requested by network operators or market participants. These programs often involve contracts and require metering and communication systems and typically include performance requirements and penalties or payment reductions if the contracted response is not delivered.

2. 'Shed' involves reducing electricity demand by turning down or switching off equipment, typically during peak periods, as seen in the Reliability and Emergency Reserve Trader (RERT) scheme.
3. 'Shift' refers to moving electricity consumption to periods of low prices, and ideally low emissions intensity.
4. 'Shape' means routinely adjusting demand to follow a preferred load profile, such as absorbing excess solar or wind generation through pumped hydro or large-scale batteries.
5. Each operation occurs over a different timescale and aligns with specific pricing and incentive schemes, as shown in Figure 14.



Time-varying price-based programs	Shape	Shift	Shed	Shimmy
Time-of-Use pricing	Green	Green	Orange	Red
Demand tariffs	Orange	Yellow	Orange	Red
Critical Peak Pricing / Peak-Time Rebate	Green	Green	Green	Red
Wholesale pass-through pricing	Green	Green	Green	Red
Controlled-load tariffs	Orange	Green	Orange	Red
Incentive-based programs				
Direct Load Control	Red	Red	Green	Red
Interruptible load contracts with aggregators	Green	Green	Green	Red
Wholesale Demand Response Mechanism	Red	Orange	Green	Red
RERT	Red	Red	Green	Red
FCAS	Red	Red	Red	Green
Other general benefits				
Network investment savings	Yellow	Yellow	Green	Red
Distribution network support	Orange	Orange	Red	Green
Grid scale renewable support	Yellow	Green	Orange	Red

Figure 14 Suitability of Demand Flexibility for different price-based and incentive-based instruments (Red to green indicate the degree of suitability, where red represents not suitable and green represents highly suitable. Yellow and orange represent medium (top plot adopted based on (Alstone et al., 2017)).

The focus in the FlexCost analysis for demand flexibility services is on technologies which can provide 'shed' or 'shift' services and to a lesser extent 'shape' services, in the minutes to hours timescale, but not 'shimmy' very fast response services.

3.2.1 Inclusion criteria

Technologies will be included in the FlexCost report when they satisfy the following criteria:

Potential impact

Included technologies are expected to be potentially capable of contributing to one or more of the following outcomes at scale:

- mean reduction during high demand periods
- Energy shifting (increasing utilisation of low-cost renewable generation)
- Improved operational controllability and dispatchability of CER.
- Deferral or reduction of supply-side investment requirements, including generation, storage and network augmentation.

Materiality

In practice, 'material' herein refers to technologies that are either already present in a significant share of dwellings (existing-asset opportunity) or are projected to grow rapidly and become a major component of electrified end-use demand (emerging electrification opportunity).

FlexCost is not intended to replicate GenCost by costing generation technologies. Measures that mainly behave as generation (e.g., rooftop PV in isolation) are not prioritised as FlexCost 'flexibility technologies'. Also, technologies at early research and demonstration stages, or those for which costs and performance are not sufficiently evidenced in Australian or comparable contexts, were excluded to avoid producing misleading point estimates. For EE measures, where mandatory standards are already legislated or embedded in the baseline scenario assumptions, FlexCost treats these effects as business-as-usual rather than an additional FlexCost option.

Comparability

The technology must support a definable output metric that can be standardised across options.

Actionability

Technologies were prioritised where they can potentially be enabled through pathways including:

- i) equipment procurement (new asset purchase cases), and
- ii) enablement of existing assets through communications, control, enrolment, and incentives (existing-asset facilitation cases).

Data availability

In order to rely on defensible techno-economic inputs, FlexCost focusses on technologies where the core cost elements can be reasonably identified and bounded for the cost elements discussed in Section 3.5. Large commercial and industrial demand response were excluded because FlexCost

(Stage 1) is explicitly focussed on residential and small business options. This is because many C&I resources typically require different contractual structures, baselining methods, and site-specific engineering assessments.

3.2.2 Categorising technologies

While technologies will be evaluated in terms of a common metric of demand-side energy, there may be other aspects of their operation that need to be assessed to ensure the cost of options can be compared on a fair basis.

Duration

An option that delivers 1 kW of demand flexibility for 1 continuous hour duration cannot be fairly compared directly with an option that provides 1 kW of demand flexibility for 4 continuous hours. If they cost the same, for example, then the option that delivers demand flexibility for 4 continuous hours may be more valuable depending on the typical duration of high demand or price events. Rather than try to calculate the value of different durations which would depend on very specific scenarios of the future of the electricity system, the simplest solution would be to separate the options into different categories according to the potential typical duration of their response (after taking into account any relevant factors such as average availability of the option and average available state of charge which might impact duration other than the nameplate capability).

Direction - Flex up vs flex down

Most demand flexibility involves reducing demand ('flexing down') at a time of supply constraint and shifting load to increase demand ('flex up') at another time without supply constraint. However, in some instances, increasing demand can be valuable in its own right, such as to ensure grid stability in times of very low or even negative net demand. It is not planned to analyse such low demand constraints in the first iteration of the FlexCost Report. However, this is an important issue that should be considered in future iterations of the FlexCost Report.

Seasonality

Some options may only be possible to implement in specific seasons of the year - air conditioner control is an obvious option that is only available during seasons and weather conditions with high air conditioner use. This suggests that option should be categorised by their seasonal limitations. Alternatively, if this only impacts a small number of options, those options might be excluded from further consideration.

Spatial

Some technologies will only be available in limited locations. For example, many options will only be available in populated areas and will be concentrated in the more populous states, or particular climate zones. For this reason, the analysis needs to either specify a location or consider the options only at an aggregated scale. FlexCost is intended to be location specific, because both technical opportunity and cost-effectiveness depend on local load shapes, network constraints, climate, appliance stocks, and existing CER penetration. For this reason, the core geographical scope will be the NEM, with national aggregation treated as a secondary extension (if required)

rather than the default reporting basis. Within the NEM, FlexCost will adopt a transparent approach to location granularity (e.g., NEM-wide averages with ranges, or regional sub-results where data permits), recognising that resource costs and deliverability will differ across locations.

3.3 Uptake potential - types of potential or factors outside costs

The literature commonly differentiates between technical, economic, and achievable uptake potential (defined in Figure 15). For FlexCost, adopting this structure may help interpret results consistently for different end-use technologies. Works reviewed in the literature suggest that technical and economic potentials are relatively straightforward to estimate in principle based on technological attributes. On the other hand, achievable potential is the most relevant to practical energy system planning and management, but harder to estimate and forecast. Achievable potential depends on program design, incentives, willingness to participate, uptake dynamics, and constraints such as delivery capacity. FlexCost calculations of cost metrics will primarily focus on estimated achievable potential (sometimes known as ‘market potential’) as this most closely approximates real world practical potential but will also consider technical and economic potential where appropriate or relevant.

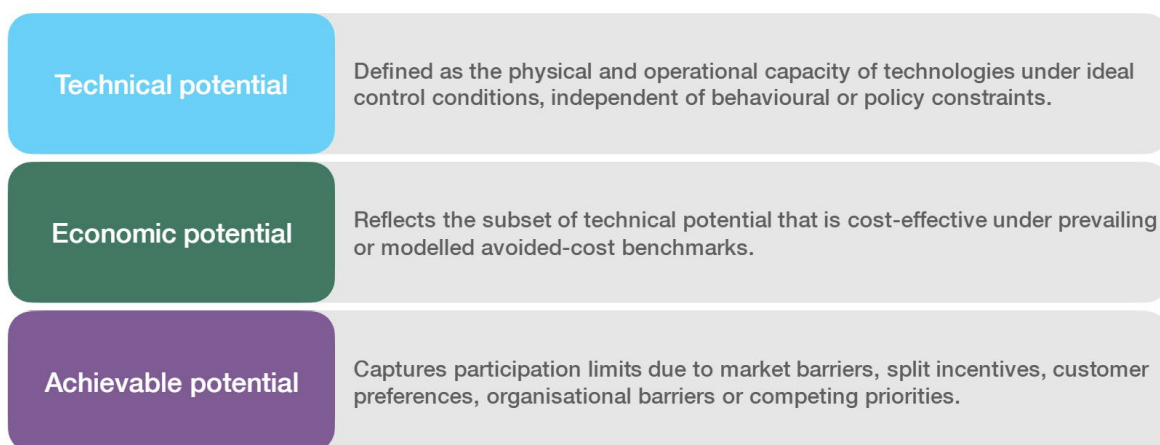


Figure 15 Description of the intended technical, economic and achievable potential assessment within the FlexCost.

Diffusion models and stock-turnover analysis have been applied successfully for product uptake (e.g., efficient HVAC or heat pumps), whereas enrolment-based resources such as automated DR or V2G depend more on program design and incentives (Lawrence Berkeley National Laboratory, 2010). Projected uptake of some technologies is already included as part of AEMO’s Integrated System Plan. Where it is not available, consumer adoption-curve approaches and trial data could provide plausible ranges. Although achievable potential can be estimated from technological principles and consumer behaviour, real world experience of actual demand-side resource programs is the most valuable guide for forecasting achievable potential.

Many EE measures appear to have negative or low costs but remain under-adopted due to split incentives, transaction costs, information barriers, other market failures, or competing customer priorities. A practical way to represent these effects is to assume that EE options only become available when equipment reaches its natural replacement point. Higher adoption levels would require additional incentives or other policy support. Mandatory efficiency standards are

therefore not treated as a separate FlexCost option. Where already in place, they are better regarded as part of the business-as-usual baseline.

Stock-turnover analysis therefore provides a suitable basis for projecting EE uptake, whereas flexibility participation may follow a different logic. For example, enrolling in a VPP or automated demand response program does not depend on physical replacement cycles but on consumer awareness and willingness, aggregator capacity, and market design. FlexCost should consider these program-based resources using enrolment or participation models and, where possible, align assumed volumes with scenario data from the ISP.

3.4 Relationship between cost and uptake

The focus of FlexCost is on defining the costs of demand-side resources, measured in \$/MWh of Available Coincident Energy. However, the cost of accessing and deploying many demand-side resources depends in part on the extent of uptake of these resources. The relationship between cost and volume is more pronounced than for supply side resources because many demand-side resource are linked to the proportion of the demand. If the demand for a particular end use increases, the opportunity to reduce this demand through energy efficiency or load management also increases.

For example, the unit cost of delivering a small amount of energy efficiency, demand response, or load shifting, may be low - but as the share of demand to be reduced or shifted rises - the unit cost of doing so may increase significantly. This upward pressure on price represents short-term diseconomies of scale, where the 'low-hanging fruit' is exhausted and more expensive or disruptive resources must be recruited. Conversely, FlexCost also accounts for longer-term economies of scale, where technological learning, economies of scale and streamlined installation processes lower the baseline cost of enablement as the industry matures.

This relationship between the cost and uptake of demand-side resources can be illustrated as a 'Cost Uptake Function' (Figure 16). This figure shows an upward sloping cost curve for the supply of the demand-side resources which tends towards infinity as the uptake approaches the technical potential of the resource.

This relationship of lower uptake at lower cost and higher uptake at higher cost highlights the importance of understanding the context of accessing demand-side resources. If the amount of Available Coincident Energy is low and cost of alternatives to demand-side resources is relatively low, then the avoidable cost of demand-side resources is also low, so only a low level of uptake is economically justified. On the other hand, if the electricity system is heavily constrained and the cost of alternatives is high, then higher incentives for demand-side resources is warranted and the achievable potential uptake of demand-side resources is correspondingly higher.

Longer-term, structural shifts from technology learning would be equivalent to the whole supply curve shifting down, signifying a lower cost is achieved at every point along the curve.

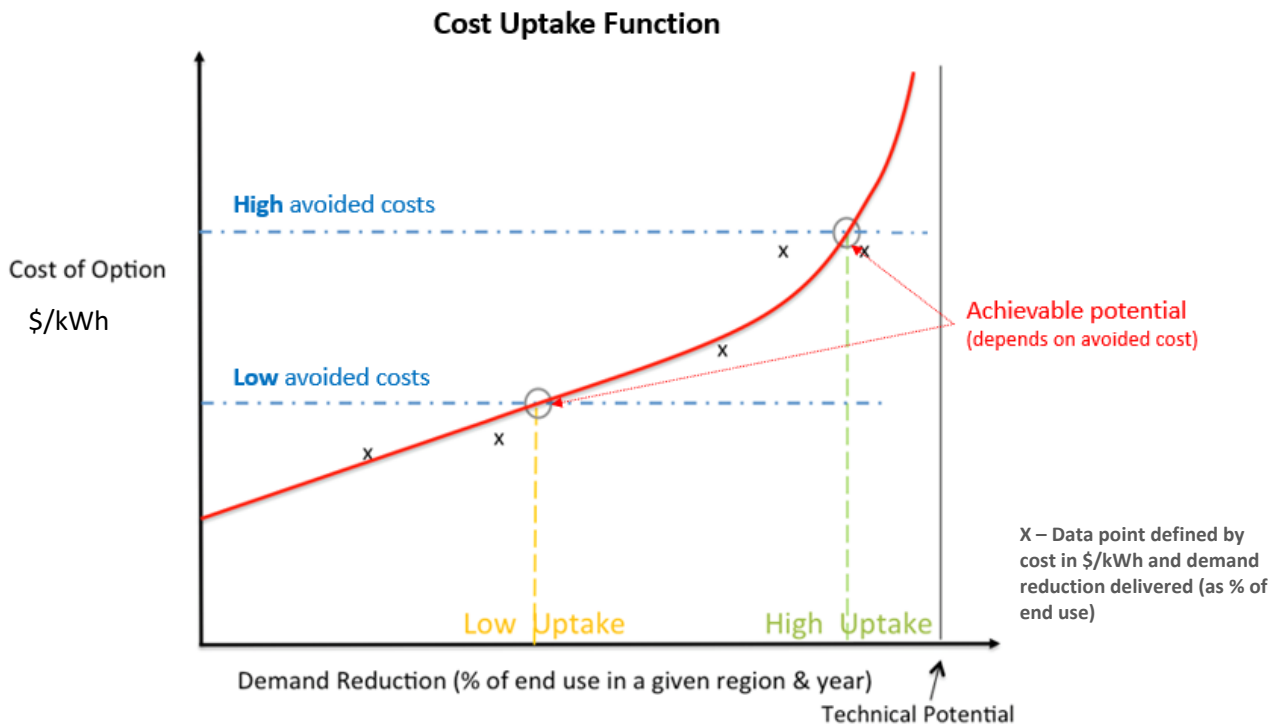


Figure 16 Conceptual illustration of technical and achievable potential using a cost uptake function

Figure 17 extends this analysis to show the relationship between ‘achievable potential’ and ‘economic potential’. The economic potential of demand-side resources refers to the level of uptake of demand-side resource that would be cost effective to adopt, taking account of the cost of the resource and benefits that would accrue. This analysis is usually done from the perspective of the costs and benefits accruing to the customer, but it can also be undertaken from the perspective of a utility or government program offering incentives for demand-side resources. Such analysis typically focusses on only financial costs and benefits, and omits various ‘external’ and non-financial costs and benefits which can also impact on the achievable uptake, such as information costs, risk and uncertainty management, impacts on customer productivity, comfort and health, and level of customer control. As a result of these other factors, the achievable potential is commonly significantly lower than the economic potential. This is illustrated below by the Achievable potential (red line) showing a lower level of uptake (x-axis) than for the Economic potential (purple line) for any given cost level (y-axis).

While the achievable potential will normally be lower than the economic potential, it is possible that in some instances the achievable potential exceeds the economic potential. For example, it may be that the Federal Government’s Cheaper Home Battery scheme represents such a case. That is, the quantifiable financial costs to the participant customer (‘participant direct costs’) after the rebate (‘incentive costs’) may exceed the expected quantifiable financial benefits to the customer. This does not mean that the participant is irrational. It may simply reflect that there are significant benefits to the customer that are not easily quantified in financial terms.

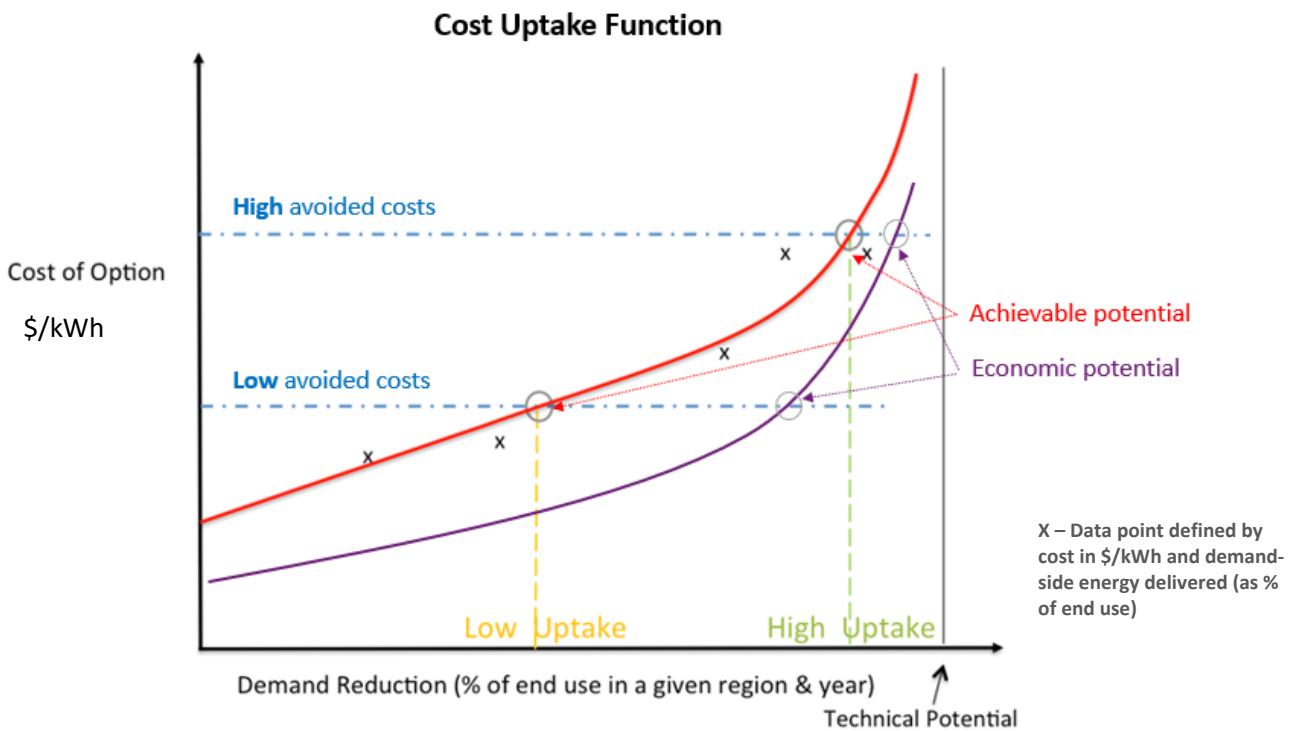


Figure 17 Conceptual illustration of economic potential in relation to the achievable potential using a cost uptake function

Figure 18 shows an example of a cost-uptake relationship for DR in a load shift context. The horizontal axis represents the quantity of shiftable energy that could be enabled to be available, on average, during a shift event at a given cost, and is used here as a measure of uptake. The vertical axis shows the annualised procurement price for a marginal kWh of shift (that is the incremental cost of enabling the next unit of shiftable resource). The stacked bars disaggregate total DR supply by flexible resources. In general, uptake is not uniform across sources. Lower cost uptake is typically drawn from a subset of resources that are comparatively easy to shift, while higher-cost uptake requires participation from resources that are more constrained, more disruptive, or require additional enabling investment and coordination. As procurement prices continue to rise, each incremental increase in price yields a smaller increase in available DR, since marginal cost increases sharply as uptake approaches the practical or technical limits of the resource.

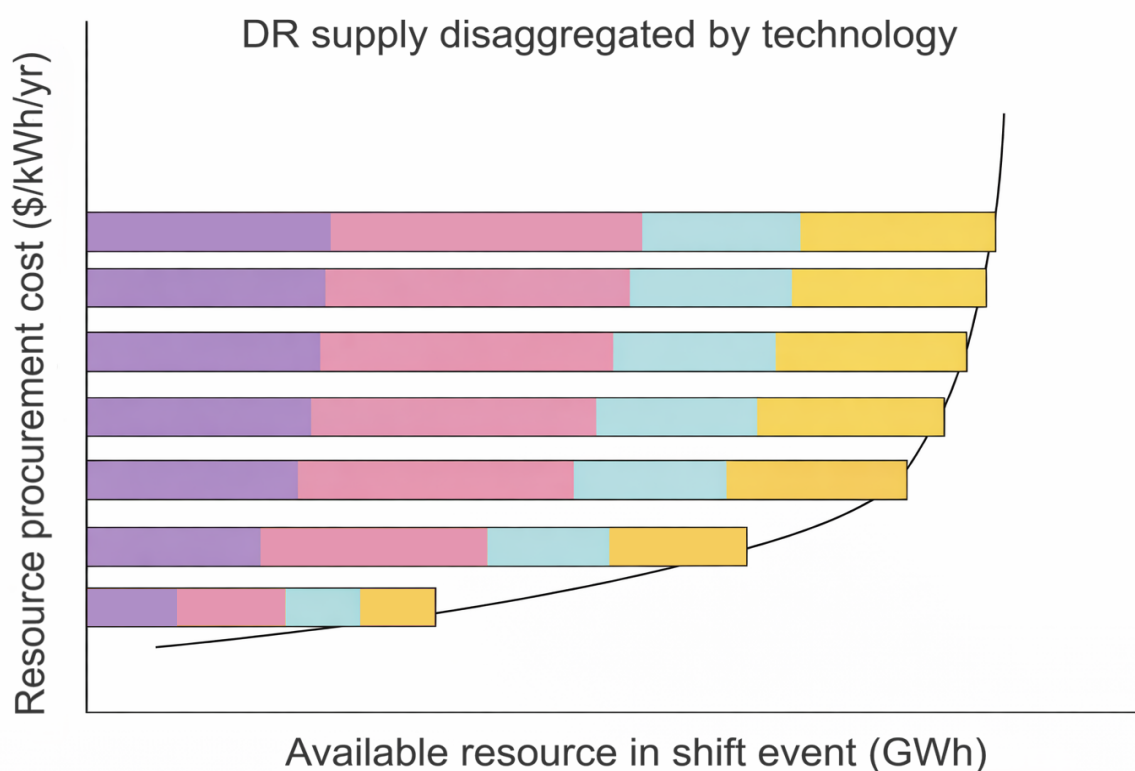


Figure 18 Schematic diagram of a DR supply curve plot for Shift, showing the total DR supply and a disaggregation by source. Based on (Gerke et al., 2024)

As another example, Figure 19 adds more interpretive layers to the cost-uptake plot: such as sensitivity to alternative weather assumptions, a decomposition of the aggregate resource into sectoral and resource contributions, and benchmark price lines. In this plot, a rightward shift indicates more enabled shed capacity is available at comparable marginal procurement costs and changes in curvature indicate how quickly marginal costs escalate as uptake increases. The weather variants curves indicate how robust that potential is to different operating conditions.

Sectoral and resource breakdowns show which sources contribute at each cost level and how the mix changes as more constrained resources are recruited. Moreover, the avoided-cost benchmark is a reference cost level that indicates the value provided to the system for shed DR. It estimates the economically efficient willingness (of the system) to pay for a marginal unit of enabled shed capacity, based on avoided system costs. The enabled capacity at the avoided-cost threshold is interpreted as the cost-effective uptake, and is used as a proxy for economic potential under the modelling assumptions. Capacity to the left of this intersection is generally cost-effective. Capacity to the right of this intersection is generally not cost-effective based on avoided system costs alone. Procuring this higher-cost capacity would require either: i) higher incentives paid to DR providers to compensate for their greater enabling, participation, or opportunity costs, or ii) additional value streams available to the purchaser or system, such as reliability, network, or other operational benefits not represented in the avoided-cost benchmark. In that case, the total value of DR could exceed the benchmark shown here, and some capacity to the right of the intersection could become economically justified.

The cost benchmark provides a technology cost reference in the same annualised units. For example, an important benchmark cost reference value would be one given by the cost of behind the meter battery technology expressed in the same annualised units. This represents the

levelised cost of procuring batteries if they were installed solely to deliver shed service.⁴ This benchmark can be interpreted as an upper bound for reasonable DR procurement costs in many settings, because (battery) storage can deliver shed without relying on customer load flexibility. The economic case for DR is concentrated below the avoided-cost threshold. When the battery benchmark is above the avoided-cost line, batteries are unlikely to be justified for shed value alone.⁵

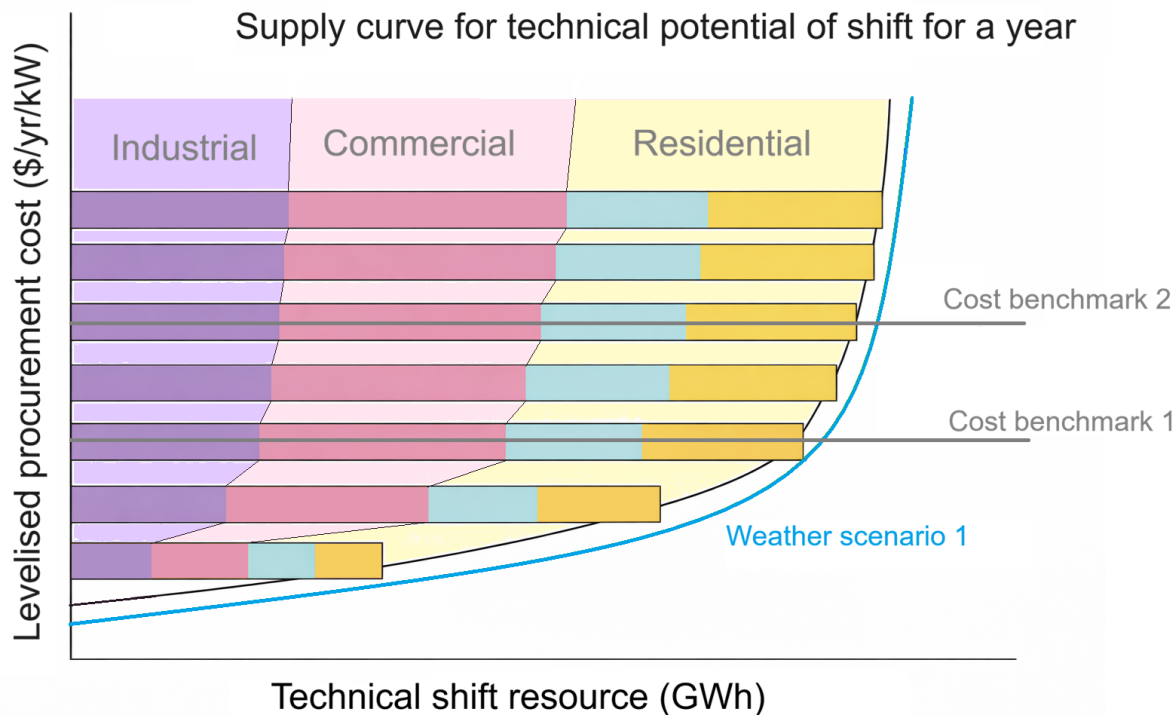


Figure 19 Schematic of supply curves for the cost-conditional technical potential of shift DR.

⁴ We note that institutional barriers such as the split incentives often limit the deployment and optimisation of batteries and other behind-the-meter assets.

⁵ In this theoretical discussion, we acknowledge that not all cases of real behaviour may be covered. Specifically, strong historical consumer adoption of larger residential energy storage indicates that end-users can frequently apply broader investment criteria or they may not act like perfectly rational economic actors. Consumers could value non-market attributes such as energy independence and backup options during grid outages above price considerations.

4 Defining costs of Demand-side Resources

Key points

It is proposed that FlexCost method should:

- Apply explicit criteria in selecting which cost categories to include. Inclusion criteria should include: materiality, data robustness and methodological consistency.
- Consider technology costs and facilitation costs in estimating costs of demand-side resources.
- Focus on facilitation costs as the most relevant costs for estimating the net impact on customers as a whole.
- Focus on the *additional* cost for facilitating *additional* demand-side resources, rather than on the existing or 'business as usual' cost of existing or business as usual demand-side resources.
- Present both cost components and aggregated levelised costs of demand-side resources.
- Include the following components in the applied Technology Costs formula: capital cost, operating cost. (Associated system costs, including network costs, should be considered, but not quantified in the first FlexCost Report.)
- Consider the following components in Facilitation Costs: incentive costs, administration costs, free rider/free driver impacts.
- Present levelised costs both as Levelised Cost of Demand-side Technology (LCODT) and separately as Levelised Cost of Demand-side Facilitation (LCODF).
- Calculate levelised costs of demand-side resources based on cost per unit of available energy coinciding with each Periods of Analysis.
- Focus on current costs rather than future costs of demand-side resources in the first version of the FlexCost Report, but also note any significant anticipated shifts in costs or technology over the next decade and consider sensitivity to different assumptions.

4.1 Demand-side Resource Costs

This chapter describes the method applied for defining and categorising costs of demand-side resources for the purposes of the FlexCost analysis. In doing so, it seeks to complement the approach for GenCost and to support a transparent foundation for cost comparison.

Topics addressed in this chapter include:

- Treatment of capital costs and operation and maintenance costs,
- Distinction between technology cost perspective and customer cost perspective.
- Facilitation costs (including incentive costs, administration cost, free rider/free driver costs) and shared versus private customer/participant costs
- How we plan to calculate the total annualised cost

- Discussion of which costs are included and excluded in the FlexCost standard unit-cost calculations possible costs and the selection criteria applied.
- Treatment of learning curves, first of a kind premium and expected changes in costs over time.

4.2 Categorising costs

Clear and consistent cost analysis is critical to allow like for like comparison, both between alternative demand-side resources and between demand-side and supply-side resources. A well-evidenced and balanced analysis of energy resources allows energy planners and policy makers to develop least cost strategies to meet customer needs.

Demand-side resources have some different characteristics to supply-side resources. Accessing flexibility and efficiency options involves different actors, cost elements and value streams that are not easily captured by a single aggregated metric. In the reviewed literature, there are four main cost perspectives (or classifications) for considering demand-side costs. Depending on the goal of the analysis, one or more perspectives can be employed. These perspectives are reviewed below and summarised in Table 3:

1. Gross Technology Costs (GTC; The ‘Engineering’ view): This covers the technology purchase and installation costs (CapEx) and operation and maintenance costs (OpEx). GTC perspective also includes any associated electricity system costs or other costs required to integrate, enable and coordinate the technology with the electricity grid, including control technologies and communication systems.

GTCs do not include program incentive or administration costs or other non-technology costs such as the ‘free rider’ (and ‘free driver’)⁶. See Figure 20 for a breakdown of GTC which shows capital and operating costs and also associated system (network) costs (which are partly to do with capital costs and partly with the operating costs).

2. Net Technology Costs (The ‘Total Resource’ view). This is the gross technology cost of demand-side resources, less specific (materially significant) avoided technology costs, usually supply-side costs such as the cost of generation capacity and fuel and network capacity.

A variant to the Net Technology Cost or Total Resource Cost perspective is the ‘societal cost’ perspective which includes non-technology costs such as environmental and health costs, and associated benefits such as improved energy reliability, comfort and productivity.

3. Participant Costs (The ‘Participant’ view). Participant direct costs include purchasing cost, while the indirect cost can include ‘search costs’ in time and effort to identify and procure

⁶ Free-rider costs represent the portion of program expenditures, such as subsidies or rebates, provided to participants who would have adopted the technology or behaviour regardless of the incentive, thereby resulting in no net additional benefit for the program’s investment. Free rider costs are wasted incentives on those who would have adopted technology without incentives, while free drivers are benefits of induced action without an incentive.

the technology.⁷ This category of costs is not equivalent with Gross Technology Costs (above) or Facilitation Costs (below). For example, here participant direct and indirect costs are included, and network costs are excluded. This category of costs is also not to be confused with the Customer Costs perspective described below. Participants are the subset of customers engaging with a demand-side program. The customer base is a broader group of people which includes both participants and non-participants in demand-side energy management programs.

4. **Facilitation Costs (The ‘Administrator’ view):** This includes expenditures (usually made by a government agency or a utility) to incentivise adoption of the demand-side resource, including incentive costs (such as rebates, discounts, subsidies, rewards and prizes), program administration cost (including management, customer engagement and measurement and verification), plus the net cost of ‘free riders’ and ‘free drivers’. Facilitation costs are the costs to government or utility to stimulate the adoption of a demand-side resource. These include incentive payments and administration costs plus any net free rider costs.

The Facilitation Costs capture only the portion of the cost that requires public or ‘shared’ funding (e.g. subsidies, rebates). For example, if a homeowner pays 70% of the cost for a smart hot water system and the government/utility provides a 30% rebate, only that 30% (plus administration costs) affects the shared electricity bills of other customers, or the shared taxation of the community if funded by government.

As can be seen from the definitions, the cost components in these perspectives are partially overlapping across perspectives. While the ‘who pays’ question establishes the perspective of the cost, the ‘additionality’ question determines the impact of the demand-side expenditures and are within the scope of this study as discussed in the Customer Costs section below.

Table 3. Cost perspectives summary table

Perspective	Costs included in the perspective
Gross Technology Costs (GTC)	CapEx, OpEx, associated system costs
Net Technology Costs	GTC minus avoided costs
Participant Costs	Direct and Indirect costs paid by user
Facilitation Costs	Shared customer or government costs including Incentives, Admin, Free rider (and free driver) costs

⁷ Direct costs can also be considered as monetary, explicit or financial costs. Indirect costs can also be considered as non-monetary, implicit, non-market or opportunity costs.

The most relevant of these cost perspectives for FlexCost are the Technology Costs (as this is closest to the approach in GenCost), the Facilitation costs and a further ‘Customer Costs’ perspective which combines costs from the Participant and Facilitation categories and includes associated system integration costs. The following sub-sections describe each of these cost perspectives in more detail.

Technology Costs perspective

The Gross Technology Costs (GTC), cover the CapEx (i.e. purchase and installation), OpEx or O&M costs and associated system costs (Figure 20). The practical application and scope of these costs is different based on the technology considered (see technology specific sections for more detail).

Annualised CapEx investment costs are initial purchase and installation costs of the technology for the benefit of the DF or EE scheme spread over the life of the asset, based on an annual discount rate and depreciated annually over the economic life of the technology.

Operating costs in our definition cover fuel costs for use under a DF or EE scheme. For example, the (energy storage) charging costs for DF assets, after activation for the DF scheme, can be considered separately (Thran et al 2025), but in this work they are considered as operating costs. Maintenance costs (if they exist) refer to costs encountered by the participant to maintain equipment in order for it to be available in a DF or EE scheme.

Figure 20 depicts how technology and associated system CapEx, OpEx and associated system costs form the total of Gross Technology Costs.

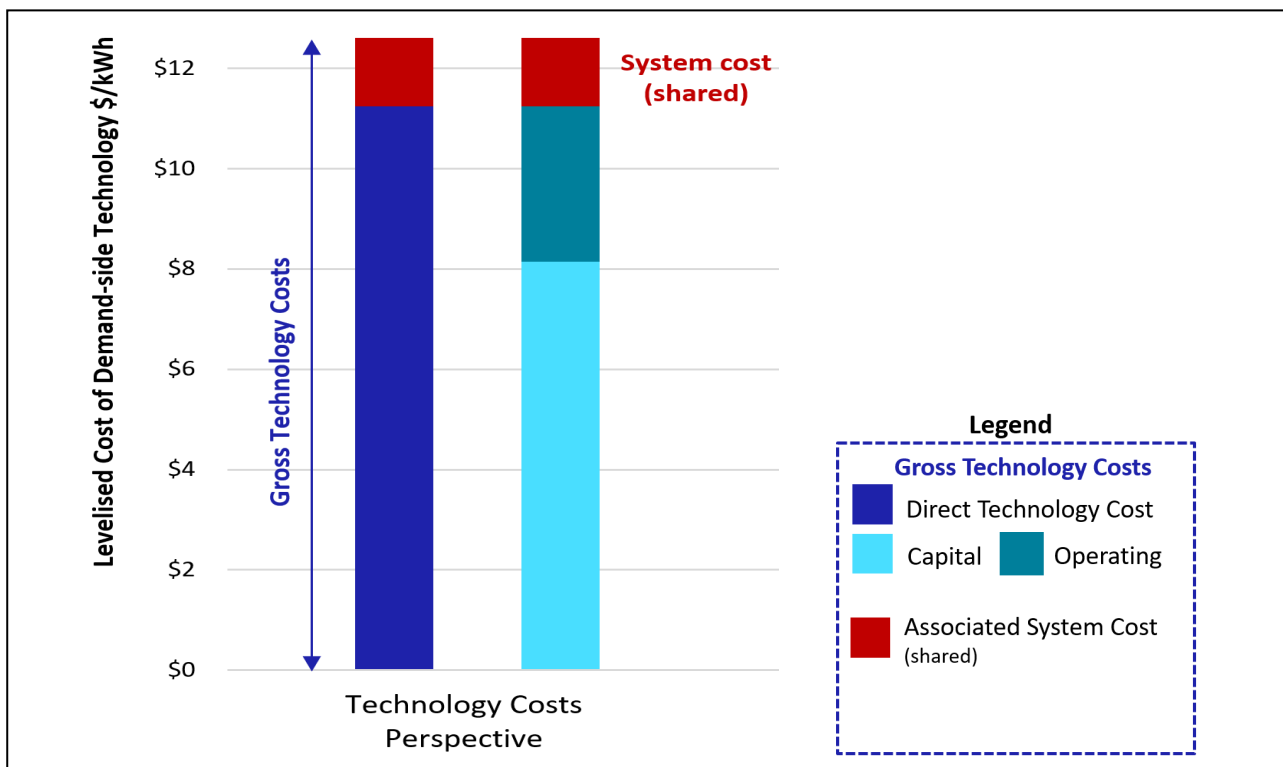


Figure 20 Illustration of the categories of costs (Technology Costs perspective)

For the purpose of FlexCost, we propose that associated system costs are considered and defined as any additional electricity supply system costs that are incurred in order to allow customers to access specific demand-side resources. These associated system costs for demand-side resources

are likely to be significantly lower than for supply side resources, because the energy provided is generated, shifted or saved at or near the point of use.

Associated system costs for demand-side resources are likely to mainly comprise of network distribution costs pertaining to upgrades in the network necessary for the integration of DSR (CapEx) or for running this additional capacity⁸ (associated operating system costs, see Figure 20). In practice, these costs would refer to both hardware and software investments, such as voltage control and automatic tap changers, or communication processes required for dynamic coordination, mostly incurred by the Distribution Network Service Provider (DNSP) to facilitate DSR integration.

The rationale for including these costs is to ensure methodological parity with supply-side assessments. Notably, the CSIRO GenCost framework has evolved to include some integration costs for variable renewables (such as storage and transmission) to provide a more accurate comparison between variable and dispatchable generation (CSIRO, 2025c), but not distribution network costs. Explicitly including these costs allows the theoretical framework to highlight the competitive advantage of DSR: while traditional supply-side assets typically require network expansion, many DSR applications require negligible upgrades or may even defer or eliminate the need for capital-intensive ‘poles and wires’ investment (Deloitte, 2023).

FlexCost will review these associated system costs (aka integration-related network expenditures) to support the development of an objective, whole-of-system economic evaluation. While this methodology report establishes the theoretical framework for identifying and categorising these system costs as an essential consideration for energy planners, providing empirical estimates for them remains outside the scope of FlexCost at this stage. Based on further research and discussion with stakeholders, whether associated system costs will be included in a future FlexCost report remains to be decided. We note that few literature resources detail the costs to the DNSP. The Deloitte Project Edge report, which details a cost-benefit analysis, has DNSP benefits evaluated across a number of scenarios as ranging between \$0.62b - \$1.62b for scenarios 2-5, which are aligned with the AEMO 2022 ISP Step Change scenario assumptions, and between \$0.74b - \$1.28b for scenarios 6-10 corresponding to a High DER outlook. These figures point to potentially sizable associated system costs.

Customer Costs perspective

The **Customer Costs (CC)** perspective accounts for the total costs required for activating additional demand-side resources. The Customer Cost perspective covers facilitation costs, participant costs and associated system costs. Defining this cost stack ensures methodological clarity and avoids the potential for double counting of technology outlays and incentives.

⁸ System costs to upgrade the network would be incurred only when running demand-side energy resources would exacerbate low-voltage street network constraints rather than relieve them. For example, So, for end use energy efficiency improvements the associated system costs are likely to be nil, while for a home battery, the associated system costs may include any additional distribution network capacity required to transport stored residential energy to other customers and a central coordination system to be installed.

The Customer Cost perspective includes expenditures by the Participant customers and the Facilitation costs, namely the incentives provided to the participants and program administration costs which ultimately are borne by customers collectively (or by taxpayers, if a government funded program). The Customer Cost perspective also includes associated system integration costs which are also borne by customers collectively (see Figure 21).

Components of Customer Costs

To ensure a 'like-for-like' comparison with the Technology Costs stack, the Customer Costs perspective consolidates three distinct cost streams:

1. **Participant Direct (Monetary) Costs:** The direct out-of-pocket capital expenditure (CapEx) and operational outlays (OpEx) incurred by the end-user adopting the technology.
2. **Facilitation Costs (incl. incentives):** The financial support, such as rebates or subsidies, provided by utilities or government agencies to stimulate adoption. The incentive costs are not borne by the participating customer but are covered by the utility or government program manager. Where it is covered by the utility it is generally recovered from all customers as a group. These costs do not include the (net) free-rider costs.
3. **Associated System Costs:** The hardware and software expenditures (e.g., voltage control or communication gateways) required by the Distribution Network Service Provider to integrate the resource into the grid. If applicable, these include the costs of other solutions to avoid network investment to manage voltage and other aspects of supply quality.

The Customer Costs perspective creates a like-for-like comparison with supply-side investments that are entirely funded by utilities and ultimately represent costs shared by all electricity customers (represented by the hashed line at the top of the Technology Costs and Customer Costs cost stacks in Figure 21). As such, in FlexCost, we propose to estimate a number of costs pertaining to GTC and Facilitation Costs across selected DF and EE options for homes and small businesses.

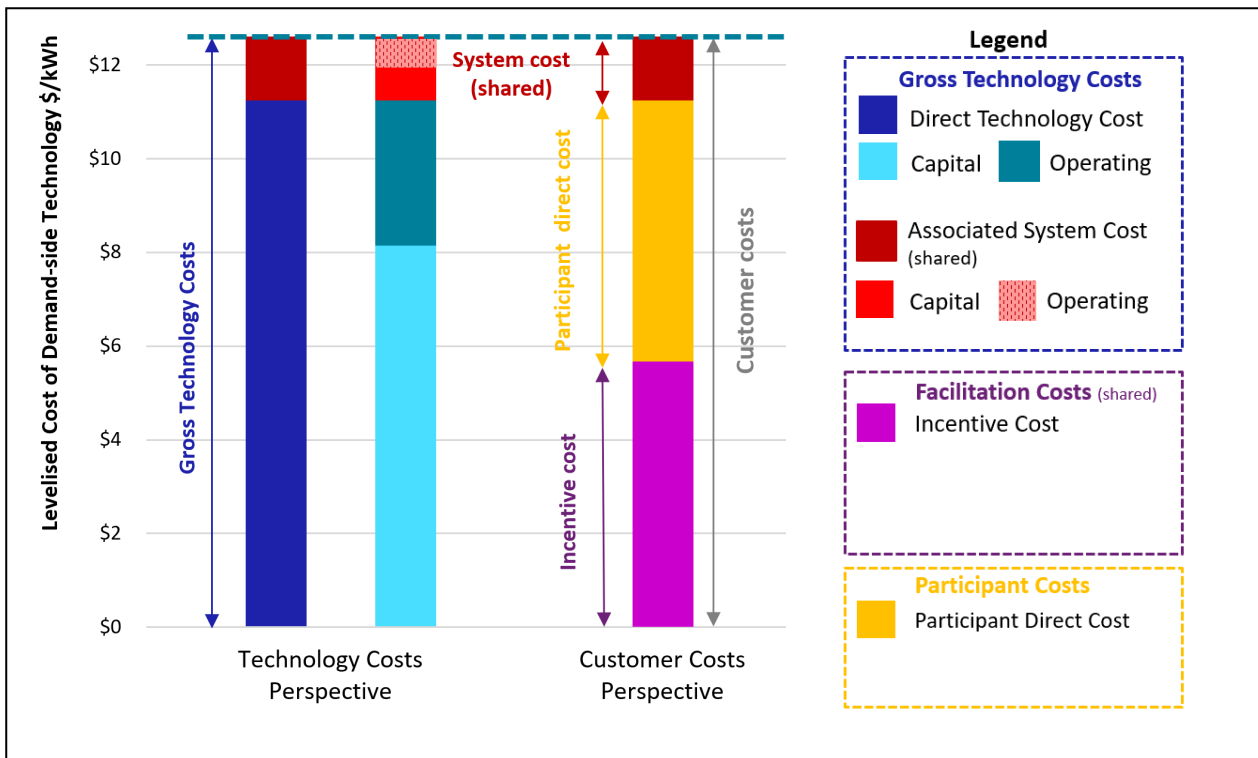


Figure 21 Illustration of the categories of costs (Technology Costs and Customer Costs perspectives compared)

Components of Facilitation Costs and additionality

The Facilitation Costs and the Customer Costs perspective are potentially uniquely suited for demand side analysis and policy evaluation. The FlexCost methodology distinguishes between stakeholder perspectives and resource procurement by using ‘who pays’ to define the analytical boundary and ‘additionality’ as the filter for data inclusion. The CC perspective enables a high-fidelity comparison with supply-side resource assessments, such as those documented in the CSIRO GenCost reports. While supply-side resources are traditionally evaluated through Technology Costs, the Customer Costs perspective serves as the theoretical demand-side equivalent (Figure 22). It represents the total cost stack that eventually flows through to the customer, ensuring methodological parity across the two sides.

The Customer Costs perspective is relevant from a customer standpoint, while the Facilitation costs are arguably the most appropriate for policy analysis and for comparing to supply side costs. That is, on the supply-side, the shared costs that flow through to all consumers are the Technology Costs, whereas on the demand-side, the costs that flow to all electricity customer (both the people who are participating and those who are not participating in demand-response measures), are the Facilitation Costs.

Facilitation costs include ‘shared costs’ such as incentive costs, scheme administration costs, and ‘free riders’ or ‘free drivers’ costs (Figure 22). We can think of technology costs as being composed of costs that are incurred privately, by the consumers directly, and costs that are ‘socialised’, that is costs like those incurred for facilitation, administration and free riders’ cost is initially borne by a ‘public’ (non-private) entity. However, ‘socialised’ costs are effectively costs which are incurred for consumers’ benefit and then recovered from consumers or taxpayers collectively. For example, the installation of new batteries will partly consist of a capital cost to purchase the battery, a cost

to install it for the user, potentially an additional enabling cost to activate it as a VPP (for older models of batteries) and then ongoing costs in the form of dispatch incentives, e.g. feed-in tariffs. The costs to purchase and enable the battery as a VPP can be subsidised through a public scheme. Therefore these costs are partly socialised.

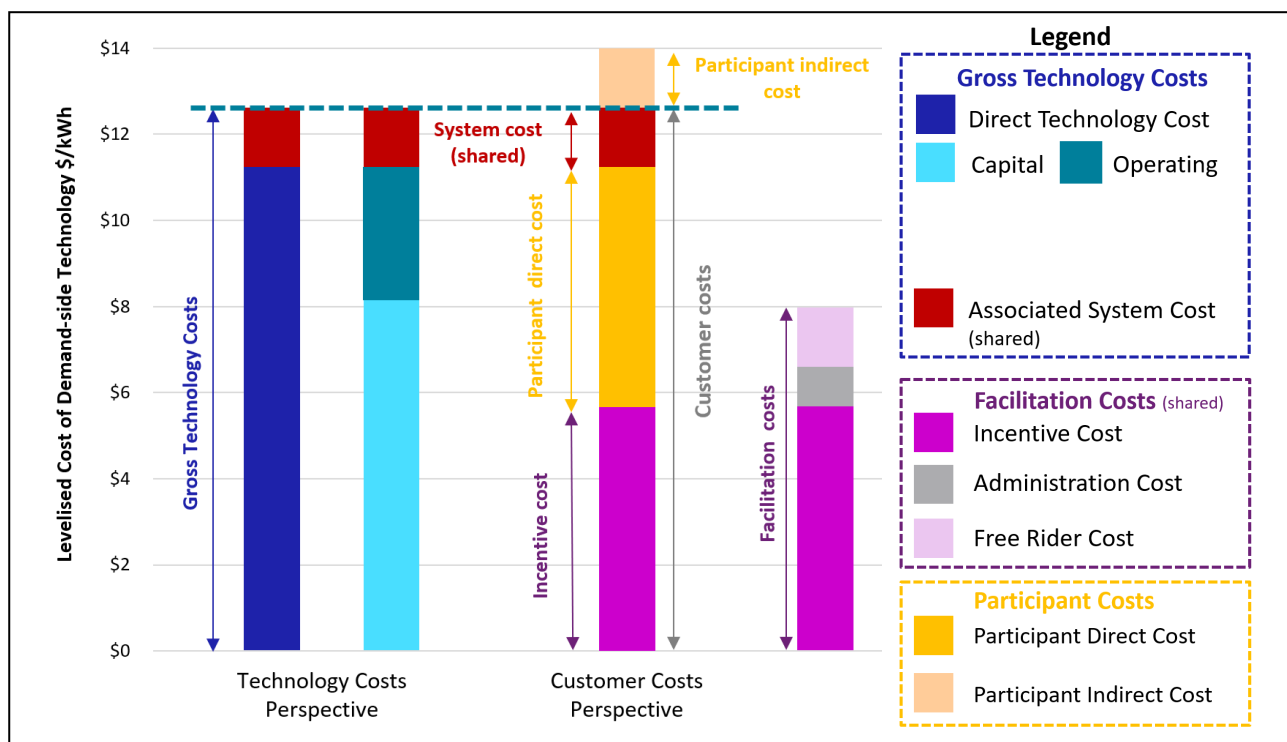


Figure 22 Illustration of the categories of costs (including the full stack of Facilitation costs)

In the procurement of demand-side resources, the primary analytical focus is on the expenditure required to secure **additional capacity**. A significant volume of demand-side resources is already embedded within the market through mechanisms such as energy efficiency standards (e.g., NatHERS), off-peak water heating, and residential load shifting (e.g., pool pumps) and markets that place little focus on energy issues at all. While the absence of these established resources would plausibly double system demand and significantly escalate consumer tariffs, their quantification is outside the immediate scope of FlexCost. Instead, FlexCost analysis focusses on the cost of accessing **additional** demand-side resources and its relative competitiveness against supply-side alternatives.

Consequently, the incentive cost, in the context of the FlexCost methodology, represents the **additional** expenditure necessary to mobilise this marginal DSR. This classification remains agnostic to the funding source (government policy vs. market utility), the financial structure (capital vs. operational expenditure), or the unit of delivery. The defining characteristic is **additionality**: whether the incentive exceeds Business-as-Usual (BAU) signals (i.e. motivates a behaviour that is not otherwise seen) and the degree to which it effectively delivers new resource capacity.

To ensure analytical clarity, incentives are distinguished from standard market transactions based on their departure from BAU:

- **Policy initiatives:** Rebates, certificates, and similar instruments are classified as additional and included in the Facilitation costs if they function in addition to existing or BAU market

signals. For example, off peak hot water tariffs that have existing for decades would not be regarded as additional, but a new cash incentive for home batteries or Vehicle to Grid would be regarded as additional.

- **Network Interventions:** Payments provided via a Regulatory Investment Test for Distribution (RIT-D) are considered *additional* incentives as they represent an unusual, non-BAU procurement of demand-side alternatives.
- **Market Procurement:** Standard feed-in tariffs (FiTs) do not constitute an incentive cost, as they reflect the BAU procurement of energy at prevailing market rates. Conversely, retailer-led demand response typically qualifies as an incentive cost as it requires intervention beyond standard market operations. An example of a market-led incentive that falls outside of policy incentives is a retailer-led Virtual Power Plant (VPP) ‘event’ credit. The retailer offers a customer a specific, high-value payment to discharge their battery or curtail their load during a period of extreme wholesale price volatility. Unlike, government rebates (which are policy-driven), these are purely commercial transactions between a retailer and a customer designed to manage wholesale market risk.

This approach maintains alignment with the GenCost which represents the supply-side cost to all customers (or taxpayers). This is because these incentive costs (together with the other facilitation costs, namely administration and free rider costs) represent the *additional* costs to all customers (or taxpayers).⁹ Effectively, this provides a transparent comparison with the supply-side costs represented in GenCost.

FlexCost only proposes to include incentive costs in the calculations of the Customer Costs stack of annualised costs (one-time investment spread over the life of the technology or the project). Incentive costs are payments that bring forward additional demand-side resources and therefore they go beyond current market operational settings.¹⁰ They can also be thought as *additional* payments and can take the form of purchase and installation subsidies or *special feed-in tariffs* that are provided only to activate these DF or EE systems. Another example of incentive costs are *availability payments*, which serve to remunerate participants for maintaining resource readiness. Within a Demand Response (DR) framework, these payments compensate commercial entities for the guaranteed capacity to curtail load. For instance, such a structure might comprise a fixed readiness fee (e.g., \$3,000 for operational mobilisation, such as back-up generation standby) supplemented by a variable dispatch incentive (e.g., \$5/kWh) for actualised load reduction.

Incentives and other support will likely be necessary to overcome market failures regarding the activation or adoption of DF and EE options. The use of technologies for these purposes is hindered by a complex mix of consumer, technical, and utility barriers (Ausgrid, 2022b; Brinsmead et al., 2021; Gerke et al., 2024; IEA, 2025a). Households often face split incentives in rental

⁹ To clarify how free rider costs are accounted for, note that they appear in facilitation costs but not in customer costs. The cost to the community from the facilitation is compensated by the windfall gain to the free riders. As such, the policy incentives can be seen to represent a wealth transfer from the non-free rider customers to the free riders, netting out to zero in the customer cost result.

¹⁰ Current settings include white certificate schemes, such as the ‘Energy Efficiency Obligations’ or ‘Energy Saving Schemes’.

markets, where landlords bear capital costs while tenants pay energy bills, alongside high upfront capital outlays and ‘the hassle factor’ of managing fragmented supply chains. These issues are compounded by information asymmetry, a lack of trust regarding third-party control or data privacy, and a perceived loss of agency over their energy consumption. Technically, a lack of standardisation between proprietary devices and difficulties in accounting for ‘value stacks’ (where a single action benefits multiple grid levels) make it hard for consumers to be fully compensated for their flexibility.

From a utility perspective, a historical CapEx bias under the Regulatory Asset Base (RAB) model has led providers to prefer large, fixed infrastructure projects over demand-side resources. To pivot toward more efficient alternatives, the AER utilises frameworks like the Demand Management Incentive Scheme (DMIS) and the Innovation Allowance (DMIAM). Trials like Ausgrid’s CoolSaver and AirconSaver programs have demonstrated the viability of these alternatives, successfully deferring expensive supply-side investments through direct incentives and DRED technology (Ausgrid, 2017, 2022b). However, lingering utility and administrative challenges remain, such as measurement and verification difficulties, internal planning silos, and a shortage of skilled workers trained in these specific technologies.

Administration costs (or program administrator costs, or non-incentive program costs) are part of the facilitation costs, as they include planning, administration, design, implementation, marketing and customer outreach, overhead, monitoring, measurement and verification, but they exclude the incentives paid to market end users.

Free-rider costs arise from program participants who would have implemented equivalent demand flexibility or energy efficiency measures independently, within a similar timeframe, in the absence of a formal incentive or tariff. These costs represent expenditures on actions that do not meet the criterion of additionality, as the resource would have materialized under a BAU scenario. The estimation of free-rider costs is fundamental to the comparative analysis of demand-side resource technologies (systems) and the comparative standing against supply-side generation. Quantifying the magnitude of this effect is necessary to refine levelised metrics, such as the Levelised Cost of Demand-side Technology (LCODT) for energy - which is discussed in the following section. For instance, if a significant proportion of residential battery installations may be categorised as free riders, e.g. 10-25%, who would have adopted the technology independently of specific incentives, the failure to account for this 10-25% would result in an underestimation of the effective expenditure required to secure demand-side capacity, thereby distorting potential comparisons with supply-side alternatives where capital outlays are intrinsically linked to the development of new, additional assets. On the other hand, the influence of early movers on others to adopt actions can deliver bonus benefits to society.

Free riders are formally defined by Schiller et al. (2020) as participants in programs or tariffs who would have completely or partially replicated demand flexibility and energy efficiency on their own and at the same time, or in the near future, in the absence of the program or tariff. Depending on the level of free ridership, there can be total, partial, or deferred free riders (Violette & Rathbun, 2014). A distinction can be made between free riders in the context of demand flexibility vs energy efficiency. While energy efficiency free riders are often motivated by ‘on-going’ bill savings from reduced energy consumption, the free riders of demand flexibility programs are driven by existing price signals and perceptions of potential profit. For example,

building owners may modify their consumption to take advantage of TOU tariffs or maximise self-consumption. If they receive incentives when their energy use had already been modified, then they are creating a free-rider cost for the incentive program.

In a position paper of the NSW Government regarding the Energy Security Safeguard, cost-benefit analyses of the two schemes under the safeguard, the Energy Savings Scheme (ESS) and the Peak Demand Reduction Scheme (PDRS), are presented. The ESS analysis shows that net free ridership (free ridership accounting for spillovers, aka, accounting for free drivers) was estimated at 13% for energy efficiency programs, but in other contexts (in the US) the two effects were found to cancel each other out (NSW Government, 2021). A series of methods have been identified as useful for evaluators to potentially deal with free ridership or free drivers and these will inform the FlexCost report as well (Violette & Rathbun, 2014).

Participant customer indirect costs of adopting demand-side resources are often unobservable. For example, the time and inconvenience to get three quotes for installing a battery, doing research on the technology they want to install, prepare for installation and so on. Governments are beginning to recognise the importance of 'one stop shops' and 'hand holding' in driving broad change.

An important distinction must be drawn between the Technology Cost perspective, which conventionally underpins GenCost evaluations, and the Facilitation Cost perspective, which offers a more salient metric for demand-side resources. From a regulatory or utility perspective, the primary objective is to quantify the volume of demand-side capacity secured per unit of incentive or facilitation expenditure, rather than focusing on gross technology capital costs or the private investment contributed by the consumer. Applying this cost analysis structure helps to clarify cost allocation between consumers, aggregators, and system planners, and also enables transparent comparison of options that involve different ownership or control arrangements, such as customer-owned electric vehicles versus utility-owned batteries.

Studies have emphasised that technology availability and tariff structures can strongly influence facilitation costs. Incorporating technology-specific availability and value factors that weight flexible energy or power by time and price may therefore improve comparability. Reporting results of different facilitation costs under alternative tariff structures would also indicate the sensitivity of flexibility economics to market design.

Although only a few studies address this directly, the available evidence suggests that enabling the operational deployment of existing flexible assets is likely to yield a lower gross technology cost and facilitation cost than procuring new dedicated devices. Therefore, FlexCost could present paired cases for each technology: 'existing-asset facilitation' and 'new-asset purchase and facilitation costs'. In applying this distinction, it is also necessary to recognise whether the flexible asset provides another non-energy primary service and whether using it for an energy purpose interrupts or constrains or amplifies that service.

Furthermore, some flexibility actions may require additional financial incentives (e.g. on-call availability or dispatch payments) to motivate participation or to compensate for inconvenience or perceived risk. Where such payments are necessary to unlock the energy flexibility service, they should be included as facilitation costs, ensuring that FlexCost captures the full expenditure required to realise the flexibility potential.

Table 4 Examples of cost types.

Cost type	Capital Cost (CapEx)	Operating Cost (OpEx) (1)	Associated System Cost (2)	Incentive Cost	Participant Cost
Demand Flex (HVAC thermostat adjustment, (e.g. Qld PeakSmart)	Communication and control equipment; upgrades to existing HVAC etc	Management costs (to ensure dispatch and comfort)	Nil	Incentives/rebates, subsidised/free equipment & installation, availability, and dispatch payments	Capital and operating costs not covered by incentives (may be nil).
Battery storage	Total battery purchase and installation cost	Energy losses (purchase volume less exports)	Any cost of meter or connection upgrade not paid by participant (3).	Battery purchase rebate, dispatch payment (If beyond normal market-driven payments/ feed in tariff)	Purchase and installation cost not covered by rebate/payment. (3)
EVs	Additional cost of smart charger/ 2-way charger	Energy losses	Cost of meter or connection upgrade not paid by participant.	Incentives/rebates, availability and dispatch payments	Capital and operating costs not covered by incentive costs (may be nil).
Storage water heaters (solar soaking)	Solar diverter, electrical works	Energy losses	Any cost of meter or connection upgrade not paid by participant.	Incentives/rebate, availability and dispatch payments (If beyond normal market-driven payments/ feed in tariff).	Capital and operating costs not covered by contribution (may be nil).
Energy Efficiency	Upgrades to buildings or equipment to save energy. (appliances, lighting, insulation, etc.)	Usually nil.	Nil.	Incentives/rebates for purchase and installation.	Purchase and installation costs not covered by incentives/rebates.

Notes: (1) Operating costs include maintenance costs; (2) Network costs are the same category of costs from either a technology cost perspective or a customer cost perspective. The column heading is coloured in red to signify that it is a shared column; (3) Any connection upgrade paid by the participant would be included in the capital or operating costs.

4.3 Costs inclusion/exclusion criteria

To ensure the calculated metrics are robust and aligned to supply-side generation costs, the inclusion of cost components in the FlexCost report will be governed by three primary criteria: Materiality, Uncertainty Minimisation, and Methodological Consistency. The selection criteria (Materiality, Robustness, Consistency) act as filters (binary Yes/No decisions on *what* to include).

1. Materiality

Materiality refers to the threshold of economic significance at which a cost component exerts a demonstrable influence on the overall annualised cost metric. A cost is considered material if its magnitude is sufficient to alter the relative competitiveness of the technology or if it represents a primary driver of the asset cost. In the context of FlexCost, given the variability of costs, there is no fixed threshold for inclusion (e.g. above 5% of the LCODT or LCODF costs), but its role as a primary driver is based on market data of current technology costs. In the process of analysing the data and writing the FlexCost report, an actual threshold may be set.

2. Uncertainty Minimisation (Data Robustness)

Uncertainty minimisation prioritises cost inputs derived from observable, verifiable market data over those based on theoretical imputation or highly variable behavioural estimates. This criterion excludes cost categories where the error margin of the estimate exceeds the value of the cost itself, or where the calculation requires the establishment of complex, unverified counterfactuals (e.g., determining net vs gross participants). This necessitates the exclusion of highly subjective non-energy benefits (such as comfort or health impacts). By excluding these high-variance inputs, the resulting metric represents a conservative, more verifiable baseline of technology cost.

3. Methodological Consistency

Methodological consistency ensures that the system boundary used for demand flexibility aligns with the ethos of established frameworks for supply-side generation (LCOE) and storage (LCOS). The selection of costs should mirror the overnight capital cost and fixed/variable O&M structure used in the supply-side cost estimation planning (e.g., GenCost). This requires the exclusion of costs that are typically treated as 'avoided costs' or 'benefits' in power system modelling (such as deferred transmission investment). These are classified on the (benefits) value side of the cost-benefit equation, not as a component of the technology's intrinsic cost stack. This separation prevents double-counting and ensures the metric can be directly compared against the cost of building new generation capacity.

A categorisation of costs and their inclusion or exclusion based on the above selection criteria is detailed in Table 5.

Table 5 Types of costs and proposed inclusion into the FlexCost report

Cost Perspective	Cost	Included / Excluded	Criteria Notes
Technology costs	CapEx: Purchase / Capital Costs	Included	Materiality and methodological consistency. This represents the primary resource cost of the asset
	CapEx: Installation / Enabling Costs	Included	Methodological consistency. This represents an essential cost to enable DF & EE use.
	OpEx: O&M Costs (e.g. Fuel costs and Maintenance costs)	Included	Methodological consistency. Standard practice for LCOE and LCOS comparability.
	T&D Network associated costs	Included	Methodological consistency To maintain symmetry with supply-side frameworks, the system boundary must capture all costs required to make the resource 'system-ready'.
	T&D Network Avoided Costs	Excluded	Methodological consistency. T&D deferral and capacity value are considered benefits (avoided costs) rather than technology costs. These belong on the revenue side of the ledger, not the cost side.
	Generation capacity and fuel avoided Costs	Excluded	Methodological consistency. These represent a threshold for cost efficiency. FlexCost is focussed on costs.
	End-of-Life / Replacement	Excluded	Methodological consistency. Standard LCOE/LCOS boundaries typically focus on the financing life or economic life of the primary asset. The economic materiality is uncertain. Their inclusion can be considered in the future.

Cost Perspective	Cost	Included / Excluded	Criteria Notes
Facilitation costs	Incentive Costs	Included	Materiality and methodological consistency. Operational incentives replace fuel costs as the primary variable expense.
	Administration Costs	Included (excluded from technology costs)	Methodological consistency. While program administration costs are relevant, because they typically derive from highly variable, programme-specific overhead allocations that lack the observable market grounding required to maintain a conservative and verifiable technology cost baseline.
	Free rider cost	Included (excluded from technology costs)	Materiality, Methodological consistency. Despite the fact that excluding these costs may decrease error margins, the possibility of these costs being quite material and the relevance to comparability of costs (sufficiently material to alter the relative competitiveness of demand-side resources), means the initial thinking is to attempt to explicitly define and include these costs in FlexCost.
	Market Costs (business as usual)	Excluded	Materiality and Methodological consistency. The purpose of FlexCost is to estimate the cost of procuring additional demand-side resources. Existing business as usual market costs and revenues (such as well-established market-based feed-in tariffs, and dispatch payments etc) would not be considered material procuring additional demand-side resources. It is recognised that a degree of subjective judgment may be required in distinguishing between BAU and non-BAU.

4.4 Levelised-cost of demand-side technology and facilitation

The proposal is for the FlexCost report to use a formula of annualised costs that will be based on the technology cost and the facilitation cost perspective.

The **Levelised Cost of Demand-side Technology (LCODT)** and the **Levelised Cost of Demand-side Facilitation (LCODF)** are calculated to estimate annualised costs for the energy provided during the constrained period from a technology cost perspective (see formula 1) or from a facilitation cost perspective (see formula 4). Therefore, we employ the term period of analysis to mean the specific period for which additional capacity is required (e.g. expected demand may exceed expected secure supply). The calculation of the supply-demand gap during the constrained energy period is detailed in section 2. The cost inclusion criteria are discussed in section 4.3 and the costs proposed to be included in the calculations are summarised in Table 5 above.

For a minimum viable product or a first edition of the FlexCost report, only the costs deemed ‘methodologically consistent’ or ‘material’ (based on theoretical considerations at this stage of the work) for each DF and EE option considered are included in the calculation, though as more information and data comes to light, this formula can be modified to reflect improved understanding.

$$LCODT_{PoA}[\$/MWh] = \frac{[CapEx_{annualised,PoA}] + [OpEx_{annualised,PoA}]}{Available\ coincident\ energy_{PoA}} \quad (1)$$

where:

LCODT: Levelised Cost of Demand-side Technology

$$CapEx_{annualised,PoA}[\$] = CapCost \times \frac{r \times (1+r)^{EconLife}}{((1+r)^{EconLife} - 1)} \quad (2)$$

CapCost: depending on the technology case, capital costs can partly consist of a capital cost to purchase the technology, a cost to install it for the user, and/or (if applicable) an additional enabling cost to activate it as a VPP.

r: annual discount rate or annual interest rate or the weighted average cost of capital, that is the annual cost of financing the capital cost (see section 4.5).

EconLife: economic life or in this contest duration of the scheme (see section 4.5).

Available coincident energy: energy from demand-side resource (MWh) delivered/available when needed, i.e. during the period of analysis.¹¹

PoA: period of analysis, the specific period for which additional energy is required (i.e. expected demand may exceed expected secure supply).

OpEx_{annualised,PoA}: annual and annualised operating and maintenance cost for period of analysis, that is:

¹¹ While in the examples in this report are adopting a simple ‘static’ multiplication calculation for the denominator, in the FlexCost report, the ACE may be calculated as a time-series.

$$OpEx_{annualised, PoA} [\$] = Annual\ Fuel\ Costs_{PoA} + Annualised\ Maintenance\ Costs_{PoA} \quad (3)$$

OpEx costs are specific costs incurred by the participant to operate their technology under the DF or EE scheme and these can include fuel (e.g. charging) or maintenance costs.

Annual Fuel Costs: these costs are a variable operation cost.

Annualised Maintenance Costs: these costs are effectively fixed O&M costs over the economic life of the technology.

From a Facilitation Cost perspective, the **Levelised Cost of Demand-side Facilitation (LCODF)** is described as:

$$LCODF_{PoA} [\$ / MWh] = \frac{Facilitation\ Costs_{annualised, PoA}}{Available\ coincident\ energy_{PoA}} \quad (4)$$

FlexCost proposes to calculate the **Levelised Cost of Demand-side Facilitation (LCODF)** as \$/MWh for the technology and facilitation costs perspectives. The LCODF is a measure of the long run marginal cost of demand-side resources generation. The Facilitation Costs are calculated as a function of the actual costs and the Available Coincident Energy (ACE). The technology-specific applied approach is described in sections 5 and 6. Energy provided during the most constrained period or the supply-demand gap is described in section 2.

The LCODT or the LCODF measurement unit proposed is \$/MWh of constrained energy to align to the LCOE unit from the supply-side. However, for individual calculations for technologies (e.g. batteries with nominal storage capacities of 10kWh), it may be different as the units will be expressed as \$/kWh of constrained energy.

4.5 Methodological considerations, excluded costs and limitations of the analysis

Each DF and EE option has distinct technical characteristics, however, the annualised technology cost framework employs a standardised calculation methodology to ensure that cost variations across technologies are attributable to a limited set of key parameters: capital expenditure, consumer incentives (for demand response and energy efficiency schemes), operation costs, asset lifetime, and temporal availability patterns. The methodology explicitly costs the ‘enablement’ of DER by accounting for distinct layers (i.e. technology and facilitations costs) of expenditure required to transform a passive asset into a dispatchable one. A number of other costs related to these options exist and often they can be discussed as elements to be added to the calculations. However, in light of past literature that proposes similar calculations, and out of the desire choose a ‘common denominator’ formula (i.e. a formula that is most easily comparable with other work), the costs components and variations below would not be included in an initial MVP.

We note here that the FlexCost method looks at energy efficiency specifically for its contribution to alleviating system constraints, acknowledging that the value of demand reduction is not universal and requires alignment with periods of constraint. Where energy efficiency impacts align with

periods of low demand and high generation, it would have a low value. On the other hand, where energy efficiency impacts coincide with supply shortfalls it may be very valuable.

The use of a levelised cost formula

The LCODT and LCODF metrics are retained primarily as simplified ‘GenCost-style’ benchmarks to facilitate broader discussion and high-level policy comparison. However, these are derivative outputs and the work acknowledges that a core value of the project lies in the underlying cost inputs, technical assumptions, and scalable unit costs (e.g., costs per building or per appliance). By disaggregating the framework in this way, FlexCost intends for the focus to remain on the technical metrics required for system security and reliability, while providing a transparent link to the communication-focussed metrics requested by other stakeholders.

Over time, the FlexCost framework will evolve its data architecture and calculation methodologies to better support the granular requirements of power system planning. A key priority for this development is the transition toward a more modular approach that allows for the precise estimation of both consumer and facilitation costs across a broad range of demand-side options.

By focusing on scalable, unit-based metrics – such as costs per building, per appliance, or per kilowatt of installed capacity – the intent is for the methodology to ensure that its underlying inputs and assumptions are technically robust and capable of being appropriately scaled across the diverse scenarios required by system operators and policy makers.

Duration of the scheme and technology life

The duration of the scheme time horizon is intended to be based on the typical economic lifetime of the demand-side resource. This will vary depending on the particular resource. Demand response programs may only last a few years. For example, customer batteries are expected to typically last for 10 years, the average duration of their warranty, but may last longer. Some building energy efficiency measures may last much longer. See Chapters 5 and 6 for discussion of technology lifetime for each demand-side resource.

Discount rate assumptions

Similar to GenCost (CSIRO, 2025c; Graham & Hayward, 2025-26), this work assumes a single discount rate of 7%. The cost of capital for every technology is assumed to have a finance interest rate (or ‘weighted average cost of capital’) equivalent to 7%, which effectively is the interest rate. This is assumed to be the real interest rate. That is if a nominal interest rate is around 10%, but inflation is 3%, then the real interest rate is 7%.¹² Oxford Economics Australia in their discount rates study for the AEMO 2026 ISP also propose 7% as the rate that promotes competitive neutrality (AEMO, 2025c; Oxford Economics Australia, 2025).

¹² While this methodology report proposes a 7% real discount rate to maintain methodological parity with GenCost’s primary outputs, it is noted that AEMO’s ISP incorporates technology-specific costs of capital and these will be considered for the inaugural FlexCost report.

Location

The initial FlexCost report will consider NEM figures that are averaged across its regions, although future iterations could detail calculations for each state individually for the LCODF calculations.

End-of-life costs

End-of-life costs are specific to each DF and EE option and can involve uninstallation and recycling costs.

Replacement costs

Technology replacement costs if end-of-life is reached or if it fails before expected end-of-life.

Associated network costs O&M transmission and distribution costs

This is the cost of transporting one MWh of electricity using a transmission line, which varies with line length and utilisation. These are considered to be included in any additional fuel or charging costs considered in the main LCODF calculations.

Benefits

Primary benefits that may be considered in potential analysis, which would be carried out downstream of FlexCost's main focus, are energy system benefits (peak reduction, reliability, deferred investment, system cost reduction, etc.). The intention is for the FlexCost report to not quantify these benefits. It should report cost and technical parameters to enable others to quantify them.

Similarly, health, environmental, employment and social benefits. These are acknowledged but not quantified in FlexCost.

Demand-side resources, such as residential energy efficiency can offer other potential benefits such as improved comfort and health. These additional benefits are important, but they are outside the scope of FlexCost, which, like GenCost, focusses on direct cost inputs rather than wider system or social benefits.

Other limitations and assumptions of the analysis

An assumption embedded in the LCODF calculations is that there is no significant period of time for installation of the technology during which interest is lost during this delay period between purchase and the technology becoming operational. If delays are considered to be material, then these initial assumptions may change, e.g. if we need to account for the 'possibility' of some delays in technologies' related costs being incurred to the actual operational phase beginning.

4.6 Time horizon and learning curves

FlexCost does not have the benefit of a model like GALLM on the supply-side, which is used by the GenCost reports to provide a projection of cost reductions through technological learning, although some modelling of learning rates exists for specific relevant technologies (Hayward & Graham, 2013; Schmidt et al., 2019). An important methodological choice for FlexCost is whether to report only current capital costs or to also project future costs. Some flexibility and efficiency options are not yet deployed at scale, and their purchase costs are expected to change as volumes increase and technologies mature. In our preliminary data review we have identified potential sources of cost curves and assumptions related to future projections (see Data sub-sections in chapters 5 and 6). However there are limitations to current data on learning curves for some of the technologies under consideration. Therefore, the intended focus of the first edition of the FlexCost report is on current costs rather than future costs of demand-side resources, while also studying significant anticipated expected shifts in costs or technology over the next decade through scenario analysis.

Limiting analysis to current conditions could overstate long-term costs and understate potential competitiveness. As such, FlexCost intends to present in subsequent editions both current and forward-looking cost cases over a predefined horizon (e.g., 10 years), aligned with projected uptake volumes and learning rates. Current capital costs will be sourced from literature and chapters 5 and 6 present draft data sources for each DF and EE option considered.

Technology costs are likely to reduce for demand flexibility options as technologies such as V2G smart chargers come down in price and smart controls and built-in energy storage spread to more appliances and equipment, due to drivers such as technological innovation or market competition. As more DF and EE services get established, facilitation costs should also progressively diminish. Initially, facilitation costs will be the highest, as they will make DF and EE schemes feasible by promoting market and regulatory evolution (e.g. better integration of standards, technology operating systems, reducing cognitive load on the consumer, establishing measurement and verification processes).

When estimating future volumes of flexibility and efficiency options, FlexCost must account for factors that limit uptake beyond technical feasibility and economic cost-effectiveness. Many EE measures appear to have negative or low costs but remain under-adopted due to split incentives, transaction costs, information barriers, inefficient energy pricing and other market failures.

An expedient way to represent these effects is to assume that EE options only become available when equipment reaches its normal replacement point, unless an incentive is provided to accelerate uptake.¹³ In line with most of the reviewed studies, mandatory efficiency standards that are already legislated, or embedded in the underlying demand projections, are treated as part of the business-as-usual baseline because they apply to all new equipment and remove some of the behavioural and information barriers discussed above. FlexCost will not focus on additional

¹³ The replacement point is not a guarantee of efficiency uptake, but a natural opportunity for efficiency gains. However, persistent barriers, such as split incentives between landlords and tenants will continue to exist at that point.

future mandatory standards in addition to those embedded in the chosen baseline scenarios. Instead, FlexCost will focus only on acceleration of EE uptake relative to this baseline via explicit incentives and associated facilitation costs.

Stock-turnover analysis therefore provides a suitable basis for projecting EE uptake, whereas flexibility participation may follow a different logic. For example, enrolling in a VPP or automated demand response program does not depend on physical replacement cycles but on consumer willingness, aggregator capacity, and market design. FlexCost should consider these program-based resources using enrolment or participation models and, where possible, align assumed volumes with scenario data from the ISP.

Uncertainty quantification in the LCODT and LCODF calculations may rely on Monte Carlo simulations to conduct a number of calculations per technology and year, while varying input parameters - with potentially an 80% confidence interval for example - around the parameter's assumed normal distribution (e.g. similar to (Schmidt et al., 2019)). Similarly, sensitivity analysis to isolate the impact of variables such as discount rates, capital expenditure, and cycle life on the LCODT or LCODF calculations will be conducted. Another option for considering uncertainty is scenario analysis.

4.7 Operating modes

Operating assumptions and functional classifications

The FlexCost framework establishes a standardised set of operating assumptions to report indicative unit costs and technical parameters for demand-side resources. These assumptions define the operational logic, specifically the scheduling and control mechanisms, under which each technology is appraised.

Crucially, while FlexCost characterises the costs of enabling these resources, it does not evaluate specific tariff designs, forecast future retail prices, or predict individual consumer contracting choices. Instead, it provides the techno-economic baseline necessary for planners to model such variables independently.

Operational framework: Operating classes

To account for the diversity in how DSR is deployed within the Australian National Electricity Market (NEM), each technology is classified into one or more 'operating classes'. These classes represent generic functional modes that dictate the resource's availability and cost stack.

- **Autonomous scheduled control:** Local, device-level intelligence that shifts load based on pre-programmed logic or local environmental triggers (e.g., 'solar soaking' via smart hot water timers).
- **Passive price response:** Load adjustment driven by consumer reaction to price signals that are predetermined or communicated well in advance (e.g., time-of-use tariffs), without external automated control.
- **Program-based demand response:** Participation in structured reliability or emergency programs (e.g., utility-led shedding) defined by specific event triggers.

- **Orchestration:** Active, real-time coordination of resources by a third party, such as a VPP aggregator, typically via cloud-based API or telemetry.

Mapping operating buckets to parameter inputs

- For each identified bucket, FlexCost proposes a suite of parameter assumptions required for costings:

Parameter Category	Description
Control capability	The technical requirement for remote vs. local activation.
Coincidence factor with the Period of Analysis	The probability of resource availability during system-critical periods.
Capacity availability factor	The expected aggregate response of a fleet compared to its nameplate capacity.
Event structure	Maximum annual event frequency, discharge duration, and mandatory recovery (rebound) times.
Enabling requirements	The hardware/software stack (e.g., AS4755 compliance, smart gateways) necessary for the mode.

Technology-specific applicability

Not all technologies are suited for every operating bucket. FlexCost identifies the applicable modes for each DSR system- such as residential batteries, HVAC systems, or EV smart charging - and reports technology-specific parameters accordingly. For instance, although a residential battery may be technically capable of all four modes, its cost and behaviour will vary significantly between 'passive response' (low facilitation cost) and 'VPP orchestration' (higher enabling and administrative costs). Similarly, it may be relevant to consider separate costings for passive vs actively controlled flexible hot water, although the costings example in section 5.4 is only an illustrative example and does not specify what type of control is assumed. A potential solution to be explored is the design of a generic technology data entry option for scenarios or other exploration.

Treatment of Electricity Pricing and Incentives

A fundamental tenet of the FlexCost methodology is the separation of intrinsic technology costs from market-based value streams.

FlexCost does not propose to estimate the specific financial benefits of different pricing options (e.g., the arbitrage value of a specific retail offer). Instead, it focusses on the incentive cost, the additional expenditure required to mobilise a resource beyond BAU market signals.

Pricing is treated as a foundational signal that influences consumer adoption, whereas incentives (e.g., rebates or RIT-D payments) are classified as facilitation costs that bridge the gap between private interest and system necessity. This distinction prevents the double-counting of benefits and ensures that demand-side options can be compared transparently with supply-side generation on a 'cost-to-build' and 'cost-to-run' basis. Assumptions would need to be explicit of what retail tariff options are available in the base case or BAU baseline.

4.8 Data adequacy and data gathering

In the absence of a dataset readymade for FlexCost calculations, the data gathering process is envisaged to follow a set of priorities or principles for data adequacy:

- Temporal and geographic specificity: Data should be tagged by its vintage and region.
- Data quality indicators: Metadata around the methods of data collection exists
- Empirical market grounding: Preference is given to data derived from observable market transactions, such as actual equipment purchase costs, installation invoices, and verified utility program expenditures. This reduces reliance on theoretical engineering models that may not account for real-world deployment barriers.
- Future (Long-term) availability consideration: The data series should ideally be from a source that is likely to produce this data for the foreseeable future, e.g. a government agency such as the Australian Bureau of Statistics.
- Licensing considerations: Ideally the data is free, open source and shared under a creative commons licence.

The uncertainty around the data will be treated through uncertainty analysis and sensitivity analysis (as noted in section 4.6).

5 Flexible demand technologies

Key points

Based on the selection criteria discussed in Chapter 4, it is proposed that the first version of FlexCost Report should study the following demand flexibility technologies:

- Home batteries (new & existing for coordinated dispatch)
- EVs with smart charging
- EVs with Vehicle to Home (V2H) and Vehicle to Grid (V2G)
- Storage Water Heaters (solar soaking)
- Solar pre-cooling and pre-heating
- Pool pumps and pool heaters

Sections 5 and 6 describe the demand-side technologies to be potentially considered in FlexCost, with Section 5 addressing demand flexibility technologies and Section 6 addressing energy efficiency technologies. These include detail on specific calculations of costs, technical parameters, and potential data sources for technologies for residential and small business flexibility customers. Not all the technologies considered below will necessarily be addressed in the first FlexCost report. Please note that all figures presented below are purely illustrative and should not be considered as definitive or reliable.

FlexCost proposes to consider for its cost calculations the current status of DER integration, but also consider potential future shifts in what the base-case may be. For example, Project Edith, led by Ausgrid, provides a practical example of a future with more dynamic pricing, as opposed to a ‘static’ baseline pricing used in the examples below. Instead of a utility remotely switching an appliance on or off (Direct Load Control), the utility could send a dynamic price signal reflecting local network constraints.

The household’s DER then can automatically respond to that price to minimise costs. In this situation the ‘cost’ of demand flexibility is shifted away from ‘readiness payments’ and toward the price-responsiveness of the software. If this becomes the default state, legacy systems like ripple control, which are ‘blunt instruments’ that lack granular feedback may become obsolete and costs to ‘activate’ this capacity may become close to zero or insignificant (after an initial phase where technology needs to be upgraded - for example upgrading inverters with models able to host a Common Smart Inverter Profile client that receives instructions from the grid).

This section of the report adds detail with regard to the method and data for technology specific calculations of their LCODT and LCODF. The LCODT and LCODF formulas from section 4.3 are applied for each technology in part as per below.

$$LCODT_{PoA}[\$/MWh] = \frac{[CapEx_{annualised,PoA}] + [OpEx_{annualised,PoA}]}{Available\ coincident\ energy_{PoA}} \quad (5)$$

$$LCODF_{PoA}[\$/MWh] = \frac{[Facilitation\ Costs_{annualised,PoA}]}{Available\ coincident\ energy_{PoA}} \quad (6)$$

For each of the demand-side resources considered below, we provide a brief description, followed by a discussion of the method for estimating each key term in the above equations.

5.1 Home batteries (new & existing for coordinated dispatch)

5.1.1 Resource description

The role of household batteries on the grid is poised to increase, as the installation of batteries and their size is accelerated by subsidies to households. Only between July and December 2025 more than 145,000 batteries providing 3,398 MWh of capacity were installed (AEMO, 2025f).¹⁴ AEMO notes in the Quarterly Energy Dynamics for Oct - Dec 2025 that household batteries installed through programs provide a “combined NEM-wide storage capacity three times higher than the largest fully commissioned grid-scale battery (Eraring, at 1,073 MWh), and in every mainland region the aggregate capacity is comparable to or larger than each region’s largest grid-scale battery”(AEMO, 2025f).

By discharging during peak evening periods, these batteries can reduce the need for high-emission and costly gas-peaking plants and stabilise the frequency of the National Electricity Market. Programs like the Cheaper Home Batteries Program, incentivise households to install home batteries, which can increase load shifting. The program also requires on-grid systems to be Virtual Power Plants (VPP) capable, which may facilitate greater participation in VPPs, although participation is not mandatory. VPPs can coordinate thousands of individual units to act as a single, reliable power station. Modern demand flexibility schemes are designed to be ‘invisible’ to the user as automated software prioritises household comfort before offering residual capacity to the grid. NEM-wide, VPP participation remains well below the number of installed household batteries, with the ACCC reporting that participating customers accounted for less than half of battery installations in 2025. More specifically, the ACCC found that 38,200 customers had joined VPPs by January 2025, however a total of 450,000 batteries had been installed by the end of 2025 (ACCC, 2025; CEC, 2026). This indicates that VPP uptake is growing, but remains constrained by household preferences for backup capacity, self-consumption benefits, and control over battery operation (ACCC, 2025).

5.1.2 Capital Costs (CapEx)

New residential battery systems are considered to be by default configured for basic self-consumption (load shifting). For new battery installations and activations, the data sources are listed in section 5.1.8.

Depending on when battery systems have been installed, they may or may not have VPP capability:

- Pre-2020 Systems: Often lack the necessary smart communication hardware or firmware updates for seamless VPP integration.
- 2020-2025 Systems: Major brands and increasingly more batteries are VPP-capable out of the box.

¹⁴ Overall there were 454,753 batteries installed in Australia at the end of 2026 (Clean Energy Council (CEC), 2026b).

- Post-July 2025: Virtually all grid-connected systems sold in Australia are VPP-ready by default to satisfy national rebate eligibility criteria.

Depending on the battery there are alternative scenarios for retrofitting, and additional costs to enable VPP participation for older batteries can come from:

- Hardware retrofitting cost:
 - Compatible smart inverter to manage both solar PV and battery charging. The inverter would need firmware that supports remote monitoring, communication and control (charge/discharge). Some smart inverters come with a Home Energy Management System (HEMS)
 - Gateway device or a HEMS. This device acts as a translator between the aggregator and the older battery's proprietary software.
 - Communication modules. Retrofittable cellular, Ethernet or Wi-fi dongles to install on the inverter and which allow communication with the VPP operator's cloud platform.
- Smart meter: given the smart meter rollout undertaken across Australia, these costs are not included in (additional) CapEx.
- Installation labour costs: switchboard upgrades / reconfiguration
- Any software costs that are not included in the costs of the hardware for retrofitting.

As a numerical example, for a 2 hour battery with a capital cost of \$500/kWh, the capital costs in \$/KW can be calculated as $2 \times 500 = \$1,000/\text{kW}$.

5.1.3 Operating and Maintenance Costs (OpEx)

Additional OpEx costs to the BAU for the residential or small business for providing the grid service can be calculated as:

$$C_{op,bat,t} = c_{elec} \times \frac{P_{bat,t}}{\eta_{bat,cha}} \times \Delta t_{DD} \quad (7)$$

$C_{op,bat,t}$: the total cost of purchasing extra electricity after discharging, assuming the initial charge came from surplus of solar power during the day.

c_{elec} : electricity price (\$/kWh)

$P_{bat,t}$: the extra power stored in the battery for providing the grid service (kW).

$\eta_{bat,cha}$: charging efficiency of the battery

Δt_{DD} : Response/deployment duration (h)

These costs may be nil in practice, as an aggregator can provide 'event credits' to ensure the consumer is not financially penalised for grid-charging (AGL, 2026).

The aggregator's operational costs can be simply approximated as being proportional to capital costs.

Annual battery additional degradation costs are considered a part of OpEx. Degradation comes from more energy throughput, more cycles, calendar ageing (batteries degrade even when they

are not in use) and operating conditions (such as excessive heat). The value of these degradation costs is approximated using values from the literature for time and cycle degradation (based on S1 to Schmidt et al., 2019), as well as part of the value of the initial capital cost. The method relies on deriving a value based on the capital cost and when the end-of-life threshold (Schmidt & Staffell, 2024) is reached. That is, an estimate is made of the time it takes for the degradation of the battery to reach a predefined value of its nominal energy capacity. FlexCost will not do additional modelling to simulate parameters such as temperature, or others, that affect cycle and time degradation. A series of operational parameters data for batteries are referenced in section 5.1.8. for the sake of completeness, although these factors may not ultimately prove to be material in the final cost results.

Annual maintenance costs can be equivalent to zero or be considered to be a fixed ratio of the capital costs. Other studies assume that operation and maintenance costs are 5% of the capital investment and assume a lifetime of 15 years for V2G and smart charging (Huber et al., 2021; Thrän et al., 2025). Battery life can be considered to be equal to the warranty period. Additional OpEx may be included in the calculations if extra warranty is costed in as part of the additional wear and tear from VPP use.

5.1.4 Associated System Costs

The integration of residential battery storage into the Australian distribution network requires different physical and digital upgrades depending on the existing infrastructure's hosting capacity. Batteries can be expected to mitigate some issues caused by solar exports (e.g., 'solar soaking'). However, if operation of a fleet of home batteries was highly correlated, for example, if tens of thousands suddenly started exporting simultaneously in response to a very high spot price event, then this could plausibly create new thermal and voltage challenges for distribution networks. Coordination and control systems and measures could be implemented to manage these risks but such systems and measures would likely bring additional system costs.

5.1.5 Resource Availability and Available Coincident Energy

To define the Available Coincident Energy from a home battery requires three steps.

1. Define the constrained energy period, as described in sections 2.2 and 2.3.
2. Define or describe the charge and discharge profiles of the home battery.
3. Compare these two data sets to define how much energy is available from the home battery in the constrained energy period. This is the Available Coincident Energy, in other words the energy delivered/available when needed in one year.

As an illustrative example, a 20-kWh battery with a 10-kW inverter could in principle, provide about 10 kW of output over 2 hours per day or 20 kWh per day of export. In practice, the available coincident energy in constrained energy periods may be significantly less, say, 10 kWh per day. If this export were to be available on say 15 days in the constrained energy period, this would amount to 10 kWh per day x 15 days = 150 kWh of Available Coincident Energy per annum from the battery.

As another illustrative example, Figure 23 shows the coincidence between annual constrained energy period and annual battery availability in NSW. The background (violet through to yellow) heatmap shows the top 100 most constrained (in this case, highest-demand) hours in NSW in 2025, while the (red-green) contour overlay shows a plausible dispatch pattern of an aggregate NSW battery fleet. The battery fleet is modelled as a power-limited 2 hour resource with 1,097 MWh of usable energy (CER, 2025), equivalent to 548.5 MW of installed discharge capacity. For each day, discharge is allocated to the two highest-price hours, while recharge is allocated to the lowest-price hours of the same day. Contour values are expressed as a percentage of installed battery power capacity, with green contours indicating battery export and red contours indicating battery recharge. The available coincident energy is identified where positive battery export contours (green) coincide with high energy constraint periods, because these intervals represent the share of battery export that is available during the constrained period.

This figure also shows how such availability can be estimated for a future year. The contour field is not a realised dispatch trace for 2025. Instead, it is the mean of annual battery-operation data from 2020 to 2024, overlaid on the 2025 top 100 high-demand-hours heatmap for NSW. The overlap therefore provides an estimate of expected coincidence in 2025, based on recent historical years price-driven battery operation. More generally, the same approach can be used for other future years by combining the projected constraint pattern for the target year with an expected battery dispatch profile, derived either from historical data or from separate modelling. Using modelled scenarios allows the analysis to account for the possibility that future high-demand/price periods may differ from historical patterns. In this way, the method can be used for forecasting by assessing flexible load availability under alternative future demand scenarios.

In this simplified simulation, discharged energy is assumed to be fully recharged within the same day, so there is no inter-day state-of-charge carryover. Recharge is preferentially allocated to four low-price hours, unless more hours are needed to satisfy the daily energy balance. Charging and discharging losses, degradation, and auxiliary consumption are not included. Finally, contours are smoothed and mapped onto a 365-day canonical year, with leap days excluded.

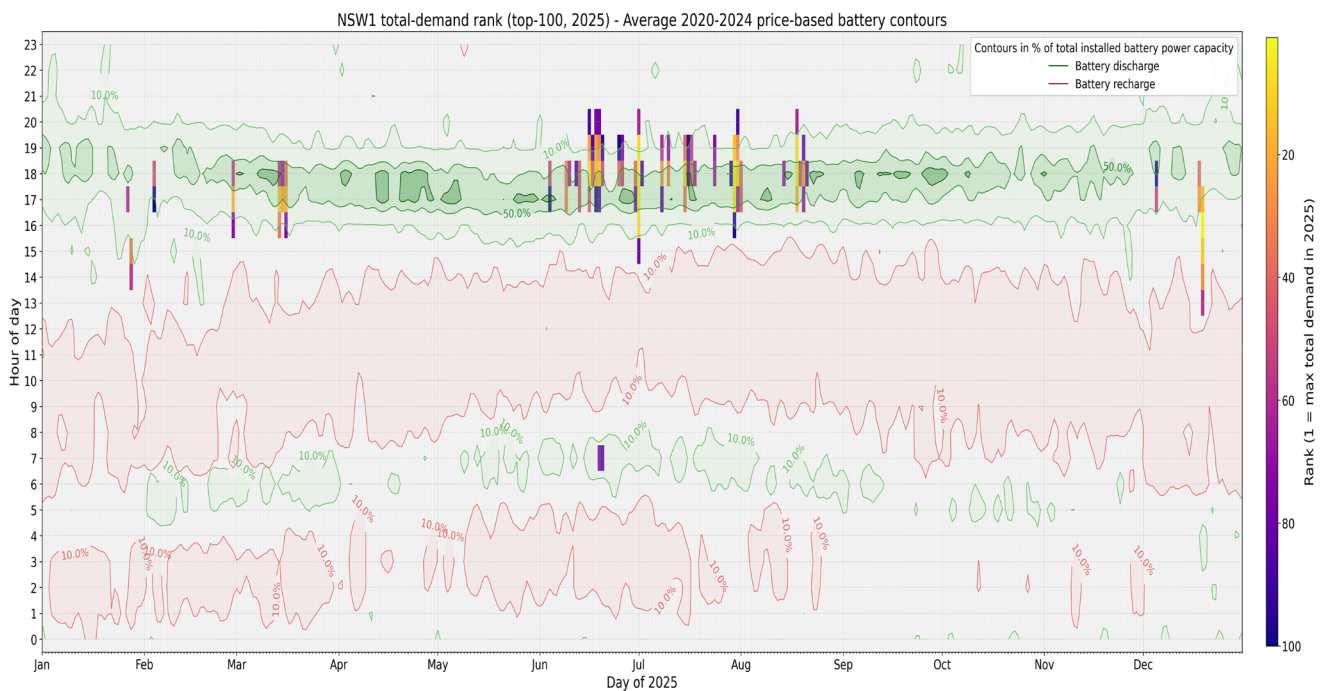


Figure 23 Coincidence of NSW households' battery availability and high net demand¹⁵.

5.1.6 Facilitation Costs

Incentive, administration and free rider costs vary from case to case. For customer scale batteries in Australia, currently the largest and most relevant example to consider is the Australian Government's Cheaper Home Battery program. In undertaking the full FlexCost analysis multiple sources will be examined, however the following illustrates how the Cheaper Home Battery program can be used to estimate facilitation costs.

Incentive Costs

The Cheaper Home Battery program allows "Australian households, businesses and community organisations [to] get a discount of around 30% on the upfront cost of installing a range of small-scale battery systems (5 kWh to 100 kWh)" (Department of Climate Change, 2025). The scale of the incentive declines over time and varies depending on system size but for a typical 20 kWh battery between May and December 2026, the value of the incentive amounts to about \$4,500, or \$225/kWh of battery energy storage capacity after fees and charges.¹⁶ Note that this is a fixed, one-off incentive cost and the battery should operate for many years. Assuming a 10-year life, the annual incentive per annum would equate to \$22.50/kWh of battery capacity per year.

¹⁵ Note: The simplified simulation shown is for illustrative purposes only.

¹⁶ 20 kWh Battery

- First 14 kWh: 95.2 STCs (14 × 6.8)
- Next 6 kWh: 24.5 STCs (6 × 6.8 × 60%)
- Total: 119.7 STCs × \$38/STCs = **\$4,549**

(Gridless, 2025).

Dividing this incentive cost of \$22.50/kWh of battery capacity per year by the estimated illustrative estimate of 7.5 kWh of ACE/kWh of battery energy capacity gives an illustrative figure of Levelised Cost of Demand-side Facilitation (LCODF) of \$3 per kWh. However, this figure is just the raw incentive cost and is not adjusted (down) for free rider rate or (up) for administration costs (nor does it include the annualised system costs).

Administration costs

Administration fees and charges amount to about 10 percent of the incentive under the Cheaper Home Battery Program (SolarQuotes, 2026a). Based on the above estimate, this equates to about \$22.50/kWh of battery storage or administration costs.

Free Rider costs

To estimate the free rider cost, it is first necessary to estimate the free rider rate, that is, the level of adoption of a technology receiving an incentive that would have adopted the technology in the absence of that incentive. To illustrate, in the 12 months prior to the commencement of the Cheaper Home Batteries Program on 1 July 2025, there were about 131,000 batteries installed, or almost 33,000 per quarter. Since the introduction of the incentive, this has risen to just over 113,000 in the December 2025 quarter and is still rising each quarter (Clean Energy Council (CEC), 2025). Based on these figures, assuming no change in the business-as-usual installation rate of batteries, this would suggest a free rider rate of 29% (33,000/113,000) based purely on Cheaper Home Battery Program.

However, there were many, more modest but significant, state government-based battery incentives in place prior to the establishment the national incentive program. It is likely that most batteries installations were stimulated by these other state-based incentives. In undertaking the FlexCost analysis, these impacts would need to be reviewed. For purely illustrative purposes, if half of the batteries installed prior to the Cheaper Home Battery Program were stimulated by state-based incentives that were no longer in operation, then the estimated free rider rate in this case would fall from 29% to about 15%.

To estimate the Levelised Cost of Demand-Side Facilitation we need to add the administration costs and free rider rates to the incentive cost. To do this, we apply the following equation:

$$\text{Facilitation Costs annualised} = \frac{[\text{Incentive Costs} + \text{Admin costs}]_{\text{annualised}}}{[1 - \text{Free Rider Rate}]} \quad (8)$$

Assuming a zero associated system cost, an administration cost of 10% in addition to the incentive cost and a free rider rate of 15% (as discussed above), the adjusted LCODF would equal

$$\begin{aligned} & [(\$3 + 10\% \text{ admin costs}) / (1 - 15\% \text{ free rider rate})] / \text{kWh pa ACE} \\ & = \mathbf{\$3.90/kWh LCODF} \text{ (adjusted for administration cost and free riders rate)} \end{aligned}$$

5.1.7 Resource Potential

The technical potential of residential battery storage as a grid-scale resource is significantly influenced by several layers of availability and operational constraints. While a consumer may install a system with a nominal capacity of 10-20 kW, the actual resource available for network

support may be restricted to a fraction of this nameplate rating due to various causes such as the state-of-charge (SOC) status at the time of a dispatch event. This capacity availability factor is a form of a capacity factor on the supply side.

In general, the capacity factor for the demand side could be considered as:

$$\text{CapacityAvailabilityFactor} = \frac{\text{Hours of available operation} \times \text{Capacity applied during those hours}}{\text{Name plate capacity} \times \text{Hours in the period being examined}} \quad (9)$$

A primary challenge to the firmness of this resource is pre-discharge; if a battery has already been depleted through behind-the-meter self-consumption prior to a peak event, its availability for grid support is effectively zero.

Furthermore, technical availability is tempered by communication outages, where the battery controller fails to respond to remote requests. Broader industry evaluations of Virtual Power Plant (VPP) demonstrations have identified that technical unavailability - due to internet dropouts, firmware conflicts, or latencies - can impact fleet performance, with some trials requiring a 'firmness' discount of up to 10% to account for non-communicating assets.

To calculate achievable potential for each technology and each period of analysis calculation would take into account a set of factors which would 'discount' theoretical technology cost maximums.

5.1.8 Data

VPP contracts have a variety of terms and conditions. Offers by VPP providers to customers can take advantage of state incentives/rebates (e.g. SA has a \$2,050 rebate through the SA Government REPS and NSW has \$1,015 through the NSW Government Peak Demand Reduction Scheme) or can offer a fixed amount, e.g. \$4,950 from a VPP provider for specific NSW councils (SolarQuotes, 2026b). Aside from state incentives, VPP providers can offer a sign-on subsidy of around \$100-\$200 and offer a wide range of on-going subsidies. In September 2025 there were offers from VPPs such as: \$1/kwh for energy discharged plus FIT, \$15-\$20 monthly credit, 800kWh per month free, or 10% discount on any grid electricity usage. Some VPP providers do not offer specific VPP feed-in-tariffs, but others do and can offer flat rates \$0.03 - \$0.05/kWh or these can be time-varying ranging from negative electricity prices to higher FITs in peak demand periods ranging anywhere around \$0.55/kWh - \$0.90/kWh with one offer going as high as \$21/kWh. VPP contracts can have relatively high feed-in-tariffs especially at peak demand, which can serve as the compensation for participation. This diversity in VPP contract structures creates challenges for VPP model designers, as participation incentives cannot be represented by a single tariff or subsidy structure. A list of data sources on battery cost and parameters, including the cost projection given in Table 6.

Table 6. Battery costs and parameter data (initial exercise for data sources identification)

Parameter	Unit	Type	Source
Battery capital cost	\$/kWh	CAPEX	CSIRO (2025c), AECOM (2019)
O&M cost	\$/kWh per year	OPEX	AECOM (2019)
Technology cost projections	\$/kWh per year	CAPEX	CSIRO (2025e)
BOS and installation	\$/kW or \$/kWh	CAPEX	CSIRO (2025c)
Replacement cost	\$	CAPEX	CSIRO (2025c)
Battery capacity	kWh	Performance	CSIRO (2024d), AECOM (2019)
Rated output	kW	Performance	AECOM (2019)
Round-trip efficiency (RTE)	fraction	Performance	CSIRO (2024d)
Charging efficiency	fraction	Performance	CSIRO (2024d)
Discharging efficiency	fraction	Performance	CSIRO (2024d)
Dispatch time	hour	Performance	AECOM (2019)
Max SOC	%	Constraint	CSIRO (2024d)
Min SOC	%	Constraint	CSIRO (2024d)
Initial SOC	%	Meta	CSIRO (2024d)
End-of-life SOH	%	Constraint	CSIRO (2024d)
Cycle life	cycles	Performance	CSIRO (2024d), AECOM (2019)
Degradation model params	varies	Performance	CSIRO (2024d)
Time degradation	%/year	Performance	Schmidt et al. (2019)
Cycle degradation	%/cycle	Performance	Schmidt et al. (2019)

5.2 EVs with smart charging

5.2.1 Resource description

The Australian electric vehicle (EV) fleet is undergoing a phase of accelerated expansion, with the total number of vehicles surpassing 300,000 by February 2025 and exceeding 410,000 by September 2025, which represents approximately 2% of all light vehicles on Australian roads (Electric Vehicle Council, 2025). By early 2026, the cumulative fleet had reached 454,000 units (Electric Vehicle Council, 2026). Most sales for new light EVs in the four quarters to September 2025 were for hybrid vehicles (around 185,000 units), followed by Battery Electric Vehicles (BEVs, around 97,000 units) and 30,000 Plug-in Hybrid Electric Vehicles (PHEVs) (Australian Automobile

Association, 2025).¹⁷ If the 2025 year's sales trend for vehicle categories applies to the overall EV stock in Australia, passenger cars, people movers and SUVs account for 95% of the EV stock.¹⁸ To facilitate the achievement of national decarbonisation objectives, the Electric Vehicle Council (2025) anticipates that approximately 1 million EVs will be needed to be in operation by 2027. The projected composition is of 800,000 BEVs and 200,000 Plug-in Hybrid Electric Vehicles PHEVs.¹⁹ Whilst BEVs currently dominate the market share, there is a distinct trend towards the increasing popularity of PHEVs and of hybrid vehicles within the residential sector.

Approximately 80% of electric vehicle (EV) charging in Australia occurs in a residential setting, with typical durations of six to twelve hours required to reach a full state of charge (DCCEE, 2023b). Within this context, the potential for residential load shifting—facilitated by third-party orchestration—primarily arises from two technical pathways:

- **Unidirectional Smart Charging:** An aggregator dynamically adjusts charging schedules based on grid requirements, provided the vehicle remains plugged in, and the user's required state of charge is met by their specified departure time.
- **Circuit-Level Control:** A dedicated meter allows power availability to be restricted to a set number of hours, with a third party enabling or disabling the circuit to manage demand.

5.2.2 Capital Costs (CapEx)

In a residential context, consumers typically install dedicated Level 2 charging infrastructure, most commonly rated at 3.5 kW or 7.4 kW. These chargers are generally hard-wired or wall-mounted units connected to a dedicated circuit and offer faster and more consistent charging than a standard household outlet. Some households may also consider 22 kW chargers, however, these usually require a three-phase electricity supply and a vehicle capable of accepting higher AC charging rates. Despite these advantages, it would be still feasible to charge EV via a standard domestic socket, which provides a power output of approximately 2.3 kW, although this approach is considerably slower and is generally more suitable for overnight or low-distance charging needs (Government of Western Australia, 2023). Numerous charging units integrate solar-optimised smart functionality as a standard feature, whereas others either omit this capability or necessitate supplementary hardware at an additional expense. The capital expenditure for unidirectional chargers typically spans from \$700 to approximately \$2,300, with the low-priced options being on par with chargers that are missing solar smart charging features. Notably, advanced smart charging attributes are increasingly accessible within lower-cost market segments (Peacock, 2026).

¹⁷ Light vehicle sales include total cars (small, medium, large and sports cars), people movers, and SUVs (small, medium and large). See categories and definitions at Australian Automobile Association (2025).

¹⁸ The rest being 2WD and 4WD utes and vans.

¹⁹ The Electric Vehicle Council document has no targets for hybrid cars. The State of Electric Vehicles report for 2025 clarifies that hybrid vehicles are considered to be fossil fuel vehicles made more efficient by their small electric motor and are not considered to be EVs.

The deployment of a smart meter is a practical prerequisite for enabling these demand flexibility mechanisms. While the continued use of conventional ‘dumb’ chargers (such as Level 1 portable cables) represents a significant barrier to demand-side participation, evidence suggests that over half of Australian EV owners (approximately 55% as of 2023) have transitioned to Level 2 charging infrastructure (Ausgrid, 2023). Given the smart meter rollout already undertaken across Australia, these costs are not included in (additional) CapEx.

5.2.3 Operating and Maintenance Costs (OpEx)

Operational expenditures are considered to encompass the operating costs of the aggregator for this particular application, while maintenance outlays are primarily restricted to the functional upkeep of the charging infrastructure additional to the BAU.

Annual operation and maintenance costs in analytical studies of the levelised cost of energy are often assumed to be a proportion of the capital costs, e.g. 5% (Geng et al., 2024; Huber et al., 2021), and this has been adopted in other studies of flexibility as well (e.g. Thrän et al., 2025).

Most warranty provided for chargers lasts between 2 and 4 years, however the lifetime of a charger used in the literature has been considerably longer, e.g. 15 years, and this can either refer to a standard chargers (Huber et al., 2021), bidirectional chargers (Geng et al., 2024) or be a general assumption around the lifetime of the scheme (Thrän et al., 2025).

This specific grid-service application of electric vehicle flexibility is assumed to result in no additional battery degradation. Furthermore, the influence of weather and other specific environmental factors on battery operation has been excluded from the proposed scope of calculations.

5.2.4 Associated System Costs

Smart meters are necessary to access EV or ToU tariffs that incentivise ‘solar soaking’ behaviours. The national smart meter rollout will support close to 100% coverage of the NEM by 2030, although outside Victoria and Tasmania in 2024 smart meter installation hovered between 39 - 46% (AEMC, 2024a). Residential premises with a smart meter in the Northern Territory reached above 35% in 2023 (AER, 2024) and around 42% of Western Australian households had a smart meter (ERAWA, 2026). Given this national rollout, the added system cost for this type of EV grid flexibility service can be considered nil.

5.2.5 Resource Availability and Available Coincident Energy

Coincidence of the constrained energy periods and the periods of the EV being available will depend on the travel patterns and the plug-in times of the EV.

The cohort who typically charge during the evening peak represents the primary target for EV smart charging flexibility services. To understand the potential for controlled charging to impact the load curve, understanding uncontrolled behaviour or what a ‘control group’ usually does is important. One Australian trial found that, in an uncontrolled scenario, there appears to be an evening peak for vehicles being plugged-in, with a quarter of the vehicles being plugged-in during

daytime anyhow (10am-3pm) (Origin, 2023). Another trial noted that TOU tariffs are already shifting the BAU behaviour of EV owners towards off-peak, overnight charging (AGL, 2023). It appears that between 40% and 55% of owners synchronise charging with daylight hours to maximise the consumption of rooftop solar PV generation (Ausgrid, 2023). However, there is still uncertainty around EV owners' behaviours, with the AGL trial report noting they failed to observe an early evening charging peak in the data and that only 16% of home chargers were used daily (AGL, 2023).

With the EV charging schedule shifted rather than reduced, the energy savings delivered are going to be financial only or relate to grid capacity not employed during constrained energy periods. That is, any energy savings from modifying the charging schedule of an EV, would be temporary only, and offset by charging the EV at other times. A formula for modelling annual energy savings during periods of constrained energy (from changing EVs' baseline charging schedule, without feeding any energy back to the home or into the grid) is:

$$\Delta E = E_{EV,baseline} - E_{EV,shifted} \quad (10)$$

Where $E_{EV,baseline}$ is the baseline energy used for charging EVs in an uncontrolled scenario and $E_{EV,shifted}$ is the total energy shifted during constrained energy periods for the V2G-enabled EVs.

Saved energy also depends on the functioning of the battery and how it degrades over time (Geng et al., 2025).

5.2.6 Facilitation Costs

Incentive Costs

An example of an incentives to support the installation of smart charging is the ACT's Sustainable Household Scheme allowing households to borrow \$15,000 at 3% interest rate (to be repaid over 10 years) for purchasing an EV, EV charging infrastructure or other energy efficiency appliances and/or to fund the installation costs for these products (ACT Government, 2025). Various state based targets and incentives are reviewed in CSIRO's Electric vehicle projections 2024 (CSIRO, 2025b).

Ongoing ownership costs are incentivised through reduced or waived registration fees, which lower the annual operational cost for the consumer. For example, the Northern Territory provides five years of free registration for new electric vehicles valued under \$50,000 (CSIRO, 2025b). Another OpEx reduction incentive is the discounted registration rates offered in Queensland, which charges EVs the same registration rate as 1-3 cylinder vehicles, which is the lowest available category, resulting in savings of roughly 25% to 70% compared to larger ICE vehicles (Queensland Government, 2025).

In general terms, for modelling purposes, the annual incentive costs (AUD/year) can be represented as:

$$C_{inc,EVs} = N \times I \quad (11)$$

where N is the number of EV incentives delivered under the program in the year and I is the average incentive per EV or per instance that the incentive is offered.

Administrative Costs

Programs such as the Fringe Benefits Tax (FBT) exemption and state-based loans (e.g., the ACT Sustainable Household Scheme) incur 'centralised' administrative costs. These are primarily related to the regulatory and compliance framework required to verify asset eligibility and manage financial transfers.

- **Eligibility verification and compliance:** Administration can involve the staff time required by agencies (such as the Australian Taxation Office) to verify novated lease applications and ensure vehicles fall below the Luxury Car Tax (LCT) threshold. However, these costs could be reduced to close to nil if processes are automated through AI.
- **Loan management and debt servicing:** For interest-free or low-interest loan schemes, costs are driven by the vetting of participants, credit risk assessment, and the long-term management of repayment schedules over a 10-year period.

Free Rider Costs

The estimation of free ridership in smart charging could be uniquely high because many EV owners already implement demand flexibility using vehicle software (timers) or manually plug and unplug to avoid peak prices (AGL, 2023; Origin, 2023). Baseline behaviour in an AGL trial failed to identify a peak charging period around 6pm (AGL, 2023). The Origin study used a baseline behaviour for people deferring charging to non-peak periods of 70% of their sample²⁰ in one of their experiments, and found that - with incentives - another 20% of participants would shift their behaviour, resulting in a 90% of the participants in the trial charging outside peak periods (Origin, 2023). Therefore, the BAU scenario for EV owners tends to be smart charging already. An online randomised controlled experiment found the baseline behaviour among participants exhibited smart charging patterns around 67% of the time (Lagomarsino et al., 2022).

5.2.7 Resource Potential

This resource's achievable potential is affected by:

- **Behavioural baseline.** A relatively high percentage of people with EVs appear to be using smart charging functions by default, potentially close to 70% (Lagomarsino et al., 2022; Origin, 2023). To incentivise additional people to smart charge, the causes for not smart charging behaviour need to be understood. Financial incentives potentially can shift some of this behaviour, but trials indicate there are that lifestyle related impediments (e.g. needing to drive out several times during the day) (Origin, 2023). As more EVs get purchased, there is a potential for the BAU to look different depending on whether there are differences in patterns of use between 'earlier adopters' and subsequent users.
- **Charging patterns for households.** An assumption is made here that the required plug-in time is made-up of one plug-in session per day, of equal duration for each household, and hence this will be equal to the average plug-in time.

²⁰ That is already 70% of people in the sample of participants in the trial were charging their vehicle outside of the 3pm-9pm interval.

- Availability of EVs due to the functioning of chargers. During grid events, chargers may experience sporadic connectivity failures and require a reboot to restore operational status (Origin, 2023)

5.2.8 Data

The data relevant to this section, including cost projection data, is incorporated in Table 7 in section 5.3.8.

5.3 EVs with Vehicle to Home (V2H) or to Grid (V2G)

5.3.1 Resource description

Vehicle-to-Home (V2H) and Vehicle-to-Grid (V2G) represent two tiers of demand flexibility where the electric vehicle (EV) transitions from an added load to the grid into a DER, capable of providing storage and discharge services that support both the individual consumer and the broader network. The usable residential EV fleet battery capacity in Australia could grow to around 500 GWh by 2035 and over 1500 GWh by 2050 (enx, 2023).

V2H is a ‘behind-the-meter’ application where the EV battery is used to power residential loads. V2H allows energy arbitrage and reshaping a home’s load profile, potentially saving homes significant electricity costs without needing a dedicated stationary home battery. Its primary function as a flexible resource is to further facilitate load shifting by storing excess rooftop solar generation during the day and discharging it during the evening peak (typically 5:00 pm to 9:00 pm) to minimise grid imports and reduce household electricity expenditure (AGL, 2023). This resource could also serve as a backup power option, especially for customers in areas with low grid reliability and after extreme weather events.

V2G involves the export of energy from the EV battery back into the distribution network. This allows the vehicle to participate in Virtual Power Plants (VPPs), providing high-value grid services such as local network support, wholesale price response, and frequency control (enx, 2023). While V2H directly benefits the individual occupant, V2G serves as a macro-level tool to maintain system security during supply-demand imbalances (enx, 2023).

5.3.2 Capital Costs (CapEx)

The implementation of bidirectional services for each additional EV enabled as a V2H or V2G flexibility device requires a sophisticated intersection of hardware, software, appropriate regulation, and regulatory compliance.

Infrastructure required for enabling both V2G and V2H functions includes:

- **Bidirectional-Capable EV.** Currently, this is most common in vehicles using the CHAdeMO EV charging hardware and communications protocol standard (e.g., Nissan LEAF, Mitsubishi Outlander PHEV), though the industry is transitioning towards the CCS2 standard with ISO 15118-20 compatibility (enx, 2023). Apparently 2,150 Nissan Leaf models had been sold in Australia by 2023 (enx, 2023). EVs can either have an on-board power converter to supply

AC power directly, or alternatively, can send DC power to an offboard inverter (enx, 2023). The vehicle must possess a Battery Management System (BMS) capable of permitting discharge.

- **Bidirectional Chargers (EV Supply Equipment - EVSE).** If the EV does not have an onboard AC-DC converter, the charger must be an inverter-based unit capable of converting the vehicle's DC power back to AC. These units must comply with AS/NZS 4777.2:2020, the Australian standard for grid-connected inverters. These units must be listed on the Clean Energy Council (CEC) approved product list, unless they have an exemption (enx, 2023).²¹ Costs are around the AUD \$10,000 mark (excluding installation), but if compatibility with the inverters of solar battery systems is possible, costs could be around half that price.
- **Charger installation costs.** Installation costs can vary significantly depending on the home configuration. Costs increase if the switchboard needs changing or a dedicated circuit needs to be added, or if more complex works are needed (e.g. trenching, load management systems, pre-wires). At minimum, installation outlays appear to be around the \$1000 mark, but they can reach sums as high as \$10,000 in complex sites (Origin, 2023). Before a charger (inverter) installation can occur, a written approval from the local DNSP is mandatory, even it is used only for V2H.
- **Smart Metering.** Smart meters are essential in order to provide the network with visibility of energy flows, and to facilitate the two-way billing necessary for demand flexibility participation. As noted in section 5.2.2, Australia is in the process of a national rollout of smart meters which should see most of the customers in the country having one by 2030. The added cost considered here is nil.
- **Home Energy Management System (HEMS).** The HEMS combines hardware and software and can coordinate vehicle charging, discharge, and household consumption including solar PVs, appliances and other technologies in the home (Energex, n.a.). EV chargers can be integrated with a HEMS and smart systems are arguably increasingly necessary for a V2G applications and highly recommended for V2H. A circuit-level monitoring system that monitors the whole-home and specific circuits will be a few hundred dollars, while systems that can actively control appliances may cost several thousand dollars (Mac Trade Services, 2025).
- **Isolation device/Automatic Transfer Switch (ATS) / Backup Gateway.** To power the home during a blackout (islanding), the system requires an ATS or a specific gateway device. This ensures that the home islands safely during a grid outage, preventing the EV from back-feeding a de-energised grid and endangering utility worker. An isolator switch can be under AUD \$50, while an automatic transfer switch can be around \$2,000 - \$3,500 (incl. installation).

²¹ While various chargers may have participated in local trials or be at various levels of CEC certification, V2G bidirectional chargers are mostly yet to be approved by CEC or be available on the Australian market (at the time of writing). See this article by Solar Choice (2026). See inverter list from Clean Energy Council (CEC) (2026a).

Unique requirements to V2H

- **Dedicated Circuit Configuration.** The home's switchboard can be reconfigured to separate 'essential' loads (lights, refrigeration) from 'non-essential' loads to ensure the EV battery is not exhausted prematurely during an outage (enx, 2023)

Unique requirements for V2G

- **Dedicated Circuit Configuration.** It is a mandatory safety requirement under Australian standards (AS/NZS 3000:2018) for all electric vehicle supply equipment (EVSE) to have a dedicated circuit. That is the EV charger is wired directly to the switchboard on its own circuit, without any other appliances or outlets sharing that circuit.
- **Aggregator Software Platform:** V2G requires a communications connection to a third-party aggregator software platform. This platform uses algorithms to dispatch the EV battery in response to market signals (e.g., high wholesale prices) or network constraints. Software platform operating costs in a trial were modest and expected to reduce with deployment at scale (AGL, 2023).

Regulatory & Installation Compliance

The transition to widespread V2G and V2H in Australia faces several regulatory and technical hurdles (enx, 2023). There are a number of regulatory aspects that need to be resolved in connection to inverter standards, EVSE to EV communications, EVSE control, and interoperability with the grid (enx, 2023). For example, as noted above, the installation of a charger must comply with AS/NZS 4777.2 (Inverter Standard) and the charger/inverter must be on the Clean Energy Council's approved list to be connected to the grid. Another example is the Open Charge Point Protocol (OCPP). Compatibility of chargers with OCPP allows communications compatibility with third-party services and allows the installation of software by the homeowner to more effectively manage the load demand within the household. However, OCPP compatibility is not yet mandatory in Australia.

5.3.3 Operating and Maintenance Costs (OpEx)

As for EVs with smart charging, some of the operating and maintenance costs relate to the aggregator software, and other maintenance outlays are primarily restricted to the functional upkeep of the charging infrastructure.

Additional costs for operating the EV as a home battery, to support shifting of load on the grid, or to feed into the grid, relate to battery and charging infrastructure degradation (Sagaria et al., 2025).

Currently, warranty provisions for EVs batteries do not cover battery degradation caused by V2G participation. Potential additional costs, for battery health monitoring and additional warranty protection, may be needed to cover maintenance costs.

5.3.4 Associated System Costs

The cost profile for V2H's network reinforcement is considerably simpler than that for V2G's. Because V2H operation primarily involves managing when and how fast the vehicle charges: drawing power from the grid to fill the battery when tariffs are low, then discharging to the home when tariffs are high. From the network's perspective during normal (non-islanded) operation, it is functionally similar to smart charging. The vehicle still draws power from the grid; it simply does so more strategically.

The key differences in network costs arises in islanded operation, when the V2H system disconnects the home from the grid to power the home from the vehicle battery during an outage. In this mode, the home's load is invisible to the network operator, which can complicate restoration after an outage if network operators do not know which premises are islanded. Protection associated with islanding management prevents safety hazards but requires additional equipment and adds complexity to the connection arrangement.

Critically, V2H does not export to the low-voltage network during normal operation, so it avoids the voltage rise problems that can accompany widespread V2G deployment. From the network operator's perspective, a V2H vehicle that uses smart charging to fill its battery overnight or during solar-rich periods is essentially indistinguishable from a sophisticated smart charger, i.e. the network costs are similar and the potential deferral benefits are comparable.

5.3.5 Resource Availability and Available Coincident Energy

For modelling total annual electricity savings from V2H, the energy savings would come from modifying the charging schedule of an EV and the reduction in energy consumption in the home:

$$\Delta E_{EV} = E_{EVs,baseline} - E_{EVs,shifted} \quad (12)$$

where $E_{EVs,baseline}$ is the baseline energy used for charging the EVs in an uncontrolled scenario, $E_{EVs,shifted}$ is the total energy shifted during constrained energy periods, i.e. energy the EVs did not draw from the grid. The reduction in energy consumption in the home is equal to the part of the usable charge supplied by the EV to cover a portion or all of the daily household baseline consumption.

For modelling annual electricity savings from V2G, the energy savings would come from modifying the charging schedule of an EV and from supplying energy into the grid:

$$\Delta E = E_{EVs,baseline} - E_{EVs,shifted} - E_{EVs,supplied} \quad (13)$$

Where $E_{EVs,baseline}$ is the baseline energy used for charging V2G capable EVs in an uncontrolled scenario, $E_{EVs,shifted}$ is the total energy shifted during constrained energy periods, $E_{EVs,supplied}$ is the total energy supplied into the grid by EVs.

The formula above recognises that V2G resource availability depends on the baseline EV use pattern of the households. Trials have either failed to find a charging peak around 6pm or that together with an evening peak for vehicles being plugged-in, a quarter of the vehicles tend to be plugged-in during daytime (10am-3pm) (AGL, 2023; Origin, 2023). Provided other trial data is unavailable, scenarios for baseline consumption will be based on best available information.

The functioning of an EV as a V2G device is strongly dependent on when the vehicle is available to charge and also when it has to depart. Therefore, the $E_{EVs, fed}$ or the coincidence of energy reduction with system constrained energy periods for this technology depends how the plugin time aligns with these periods of constrained energy.

A key technological constraint is the functioning of the battery, or rather the way it degrades over time and how this affects the energy savings gained. Geng et al. (2025) propose a model of battery degradation based on cycle ageing and calendar ageing which calculates capacity loss totals over time.

One way to evaluate baseline resource availability of EVs for V2G applications is to base calculations on traffic data on major roads, i.e. traffic monitoring when cars are on the road and when they are not on the road (using data employed for (CSIRO, 2025b)). Based on this data an average daily availability factor or an average hourly availability percentage for each time of the day can be determined.

To calculate the coincidence with a constrained period or relevant period of analysis, in this case the relevant period of time when the vehicle is plugged in and is not charging, Thran et al (2025) propose an availability factor formula as described below.

a_f^{V2G} Availability factor for V2G (fraction of time that an EV is plugged in for)

$$a_f^{V2G} = \frac{\Delta t_{RP} - \Delta t_{cha}^{day}}{24h} = \frac{\Delta t_{RP} - \frac{E_{drive}^{day} \times a_{HC}}{\eta_{cha} \times P_{cha}^{cap}}}{24h} \quad (14)$$

Δt_{RP} : Daily required plug-in time (RPT) to which consumers have agreed in h

Δt_{cha}^{day} : Daily time required for charging EV in h

E_{drive}^{day} : Energy used by EV daily for driving in kWh

a_{HC} : Fraction of EV's driving energy charged at home

η_{cha} : Efficiency of charger

P_{cha}^{cap} : Power capacity of EV charger in kW

Using Thran and colleagues' equations, the energy supplied to the grid is:

$$\begin{aligned} E_{EVs, supplied} &= P_{app}^{cap} \times \Delta t_{DD} \\ &= N_{cha}^E \times (E_{EV}^{max} \times (1 - a_{GMC})) N_{cha}^{contr} \times a_f^{V2G} \times (E_{EV}^{max} \times (1 - a_{GMC})) \\ &= N_{cha}^{avail} \times (E_{EV}^{max} \times (1 - a_{GMC})) \end{aligned} \quad (15)$$

N_{cha}^E is the number of estimated required V2G chargers for energy (or power applications)

N_{cha}^{contr} is the number of contracted V2G chargers required

N_{cha}^{avail} is the number of the actual available chargers

E_{EV}^{max} the EV battery usable energy capacity in kWh

a_{GMC} guaranteed minimum charge for the EV in %

P_{app}^{cap} is the total needed power capacity for a grid service in kW

Δt_{DD} discharge duration for a grid service in h

As in the previous section, a purely illustrative example of Available Coincident Energy (ACE) calculations for an EV being enabled for V2G VPP and its LCODF associated cost are described in this section and the following. To calculate the daily ACE, it is assumed the EV is available 60% of the time during a constrained period of 2.5 hours per day (an assumption of the average hours per event). Another assumption is that the effective load reduction per home (customer) per day for a period of analysis under consideration, e.g. acute constraint, is 5 kW/home. In this case, the Available Coincident Energy for load reduction per day will be: $2.5 \text{ h} \times 0.6 \times 5 = 7.5 \text{ kWh}$.

The yearly ACE, or ACE available during the period of analysis as energy reduction per home per year, is calculated as the product of constrained energy days per year (20 days) and the ACE per home (for load reduction) available per day: $\text{ACE yearly} = 7.5 \times 20 = 150 \text{ kWh}_{\text{POA}}$.

5.3.6 Facilitation Costs

Incentive Costs

Incentives for Electric Vehicles (EVs) in Australia are transitioning from broad purchase subsidies to targeted support for smart charging infrastructure and bidirectional capability (V2H/V2G). These incentives aim to reduce the ‘capability gap’ between standard unmanaged charging and grid-integrated orchestration. Incentives to do with EV purchase and ongoing ownership costs have been described in section 5.2.6. Here only incentives pertaining to V2G services are summarised.

Availability of EVs for supporting the grid, i.e. during ‘grid events’, is highly variable and does depend on financial incentives, namely tariff structures. Aggregators may provide ongoing participation credits or ‘event-based’ payments to users who allow their battery or vehicle to be orchestrated for grid support services. Modelling showed that tariff arrangements for V2G can be more beneficial financially than smart charging in jurisdictions such as Tasmania (\$1,560 of net present value for 10 years to 2033) and over \$6,000 (net present value) in NSW and SA (enx, 2023). DNSPs have been encouraged to collaborate to ensure tariff structures and network support service arrangements do provide the right signals to shift behaviour from the BAU and align consumer export behaviour with the requirements of the broader electricity market (enx, 2023).

In trial by Origin, the participants declared the incentive format most likely to make them change their behaviour would be credits on the electricity bill and 76% declared that 10c/kWh (i.e. a discount of up to 50% on the price of electricity) was enough to change their behaviour (Origin, 2023).

To obtain a rough LCODF calculation (which excludes administrative and free riders’ costs), we assume an upfront incentive of \$3,000, an interest rate of 7% and an analysis time horizon of 10 years. This yields an annualised incentive value approximated to around \$399. Considering a dispatch incentive of \$75 per annum, we can get a total incentive cost of around \$474. In this case the LCODF is $\$474/150 \text{ kWh}_{\text{POA}} = \$3.16/\text{kWh}_{\text{POA}}$.

Administrative Costs

Data from Australian orchestration trials indicate that these costs are divided into technical and participant-facing streams.

- **IT platform and VPP maintenance:** Orchestration requires the operation of a cloud-based Virtual Power Plant (VPP) platform. The administrative cost includes software licensing, cybersecurity compliance, and the maintenance of communication protocols like OCPP (Open Charge Point Protocol)(Origin, 2023).
- **Technical Orchestration Fees:** The cost of managing vehicle data through a software platform. In trial settings, these facilitation costs have been estimated at approximately \$149 per annum per site (charger), but having the potential to be reduced through a large-scale rollout (AGL, 2023).
- **Customer onboarding and technical support.** V2G trials have identified a high administrative burden in the ‘initial setup’ phase. This includes coordinating with electricians for bidirectional charger installation and providing ongoing troubleshooting for Wi-Fi or vehicle-to-charger communication connectivity issues (AGL, 2023). Additional costs of servicing customers unfamiliar with vehicle charging management and EV behaviour, and so needing support, was estimated to be more than double the software platform operating cost in an Australian trial (AGL, 2023).

Free Rider Costs

In a V2H context, free ridership is most likely to manifest through autonomy and resilience driven adoption. Even in the absence of a demand-side incentive or a time-of-use price spread, a segment of the market may invest in bidirectional infrastructure primarily for emergency backup and energy independence.

To estimate the free rider cost for V2H or V2G, it is necessary to identify the proportion of participants who would have installed bidirectional capability without the incentive. Although half of Australian EV owners (approximately 55% as of 2023) have transitioned to Level 2 charging infrastructure (Ausgrid, 2023), currently, the baseline adoption of V2G-capable hardware in Australia is negligible due to the lack of other adoption drivers under BAU and the significant hardware premium. Given that bidirectional charging is currently in a nascent stage within the Australian market, relevant findings and data from international V2X trials can be utilised to calibrate these assumptions and ensure the FlexCost analysis will reflect global trends in technology additionality (ACIL Allen, 2023).

5.3.7 Resource Potential

V2G services are constrained by several factors:

- **Charger Certification:** To export energy, a bidirectional charger must be certified under AS/NZS 4777.2:2020 and listed on the Clean Energy Council (CEC) approved product list. As of early 2026, only a handful of units (e.g., Sigenergy SigenStor, V2Grid Numbat) have achieved this status for residential use.
- **Warranty Concerns:** Many manufacturers do not yet officially support V2G or V2H in their standard Australian warranties. Unauthorised use of bidirectional discharging may void the battery warranty for certain brands, acting as a significant deterrent for owners.
- **Cost of Hardware:** The capital expenditure for a V2G-capable DC charger remains high, often exceeding \$10,000, compared to the costs of a standard smart charger.

- **Intermittent or persistent communication issues:** Smart chargers may not be transmitting data to the software platform (AGL, 2023). Cellular and internet coverage play a role in whether communication can occur smoothly, but there is a host of reasons behind communications issues that need to be mitigated (AGL, 2023).
- **Vehicle battery state-of-charge, location and coordination with solar:** Home AC chargers do not by default provide features to monitor a battery’s state-of-charge, a means to distinguish between home and away charging, nor to coordinate with rooftop solar systems. To better control the charging process, a vehicle API trial has been carried out in Tesla cars to test how information can be made available to a third party, such as information about the battery state-of-charge and location of the vehicle when charging, among others (AGL, 2023). In the future, the vehicle industry may provide specific third-party APIs, as for home batteries.

5.3.8 Data

Table 7. EVs related costs and parameter data (initial exercise for identification of data sources)

Parameter	Unit	Type	Source
Participation rate	% of eligible	Program	Electric Vehicle Council (2024c), CutlerMerz (2023), AGL (2023)
EV battery energy capacity	kWh	Performance	Electric Vehicle Council (2024c), Thrän et al. (2025), Department for Transport and Driver and Vehicle Licensing Agency (2025)
Opt-out rate	%	Program	AGL (2023), CutlerMerz (2023), (Origin, 2023)
Initial SOC	%	Performance	Energeia (2024)
Charger’s power capacity	kW	Performance	Thrän et al. (2025)
Base plug-in time (avg)	h	Performance	(Department for Transport, 2025), Thrän et al. (2025),
EV battery charging efficiency	%	Performance	Thrän et al. (2025), Zhang et al. (2016)
EV battery discharging efficiency	%	Performance	Thrän et al. (2025), Zhang et al. (2016)
Guaranteed minimum charge	%	Constraint	Thrän et al. (2025), Octopus Energy (2024)
Frequency of charge	%	Constraint	CutlerMerz (2023)
Charging rate	%	Constraint	CutlerMerz (2023)
Calendar life limit	years	Constraint	Manufacturer/EVC
Mileage life limit	km	Constraint	CutlerMerz (2023), (Electric Vehicle Council, 2024c)

Energy consumption rate	kWh/km	Performance	Origin (2023), CutlerMerz (2023), AGL (2023), CSIRO (2025b)
Average daily commuting distance	km/day	Meta	(Electric Vehicle Council, 2024b)
Road vehicle kilometres travelled	Vehicle kilometres per year	Meta	CSIRO (2025b)
Age threshold for battery replacement	years	Constraint	Assumption, Pickles (2024)
Battery cycle life	Cycles or SoH	Performance	Geotab (2024), Pickles (2024)
Battery cost	\$/kWh	CAPEX	CSIRO (2025c)
Charging profiles	kW per hour of day	Performance	Energeia (2024), CutlerMerz (2023), CSIRO (2025b)
Incentives	\$	Program	CutlerMerz (2023)
General EV costs	\$	CAPEX	(Electric Vehicle Council, 2024c), Electric Vehicle Council (2024b)
Cost to enable charging	\$	CAPEX	(Electric Vehicle Council, 2024c) (Electric Vehicle Council, 2024b)
EV sales	count	Meta	CSIRO (2025b)
Summary of state government EV incentives	-	Meta	CSIRO (2025b)
Projection data	count	Meta	(Electric Vehicle Council, 2024c), CSIRO (2025b)
Aggregator software	\$	OPEX	(AGL, 2023)
Customer support	\$	OPEX	(AGL, 2023)

5.4 Storage Water Heaters (solar soaking)

5.4.1 Resource description

Resistive electric domestic water heaters (RDEWH) or electric water heaters with ‘smart’ controls can be used for their demand flexibility services to store excess PV generated electricity in the form of thermal energy. By shifting this load from overnight ‘off-peak’ periods to the middle of the day, solar soaking helps mitigate ‘minimum demand’ issues on the grid and reduces the need for solar curtailment.²² More than 50% of Australian households have either resistive or heat-pump

²² Traditional residential ripple control involves using a central command signal to switch electric hot water elements on at night and off during the day, utilising the tank’s thermal storage to meet daily demand while reducing peak-time network load. Goldsworthy and colleagues (2021) note that in southern Australian states, where reticulated gas is extensively utilised for water heating, the hot water sector accounts for only 6% to 15% of minimum grid demand,

water heaters (Goldsworthy et al., 2021; RACE for 2030, 2025). Most of these are likely to be on off peak or controlled tariffs. Given that smart meters are installed in nearly all of the roughly one third of households with PVs, this potentially provides visibility of such electrical loads in real-time. But this does not necessarily provide the means to coordinate control of water heaters.

Estimates of the benefits of this flexible load source for the Australian residential sector show that electric water heaters could provide a range of 8 - 15 GW capacity or 15-31 GWh/day additional to a BAU by 2040 (Roche et al., 2023).

5.4.2 Capital Costs (CapEx)

Capital costs for purchase and installation of RDEWH are listed in Table 8. Without any subsidies these costs can range between \$920 - \$2330 without installation (variation based on capacity that fits a smaller to a larger household) and between \$1540 - 2950 with installation (Same Day Hot Water Service, 2025).

While technically, water heaters may be relatively easy to retrofit with additional hardware for demand flexibility services, enabling this option can involve additional rewiring costs. Social and economic barriers have also been found to play a role in slowing the activation of water heaters as demand flexibility technology (Roche et al., 2023; Urmee et al., 2018).

Frequently used options for control and scheduling are re-wiring on a separate circuit (controlled load), timers, solar diverters (self-consumption of excess PV electricity), and Demand Response Enabling Devices (DREDS) to allow DNSPs remote control of overall power consumption (for a fuller list, see Roche et al. (2023). Costs for timers can be around \$400, diverters \$1,200 and for establishing a new electric connection \$250 (RACE for 2030, 2025).

Control options, to allow shaping or shifting demand, are either integrated or need to be retrofitted. The previous national standard requiring DR modes has been withdrawn (AS/NZS 4755.3.3:2014). Although AS 4755.2:2025 has been published, there are no national DR obligations. States potentially have their own requirements and legislation.

Warranties tend to be for 10-12 years and assumptions for system life are similar, e.g. 13 years (Roche et al., 2023). A 10-year lifetime assumption is proposed for use in the FlexCost report.

5.4.3 Operating and Maintenance Costs (OpEx)

Running costs will vary based on whether the system is set as an off-peak system or a continuous storage unit (accessing electricity non-stop and heating the element whenever the temperature drops). The operating costs of running an resistive electric storage heater without solar soaking can be quite high compared to capital costs over the lifetime of the device (e.g. Roche et al.,

while in New South Wales and Queensland, where electric resistive systems are more prevalent, hot water represents a significantly higher proportion, ranging from 21% to 36% of minimum demand.

2023). However, when part of the energy needed to run the water heater comes from excess solar power usage, costs can be much reduced.

Maintenance costs for domestic water heaters are generally low, particularly as many consumers never undertake any maintenance at all. The recommended baseline maintenance involves annual professional servicing to manage failure risks. This includes flushing the tank to remove sediment (to maintain resistive element efficiency), testing the Temperature and Pressure Relief (TPR) valve, and inspecting the smart control interfaces to ensure remote dispatch commands are being executed.

Maintenance undertaken once every four years has been estimated to cost \$550 (RACE for 2030, 2025). Some manufacturers recommend that a major maintenance service should be carried out by qualified people once every six years and minor maintenance should be carried out in the home every six months (Rheem, 2025b). Associated maintenance costs can be assumed to be around the \$1,000 - \$1,200 mark for the life of the scheme or product (e.g. a 10 year lifetime), if it is undertaken at all.

However, most of these OpEx costs are associated with the water heater regardless of whether it is used for demand flexibility or not. Accordingly, the *additional* OpEx associated with demand flexibility are likely to be small to negligible.

5.4.4 Associated System Costs

Associated system costs are expected to be small. A trial found the exchange of meters was clunky (Rheem, 2024), but if most customers already have smart meters, then associated system costs can be assumed to be nil.

5.4.5 Resource Availability and Available Coincident Energy

The operational availability of flexible Domestic Hot Water (DHW) systems is governed by three primary constraints: the necessity of meeting immediate household demand, the finite volumetric storage of the vessel, and the maximum power intake of the heating unit (Dyson, 2015). A method for estimating daily average residential electricity demand on the NEM for domestic hot water was proposed by (Goldsworthy et al., 2021).

Potential energy savings depend on the resource availability period coinciding with the constrained periods. The BAU energy usage scenario would depend on the type of storage hot water system, whether it is (or it is set as) an off-peak system or a continuous storage one. Therefore, for modelling the total energy savings

$$\Delta E_O = E_{RDEWH_O} - E_{RDEWH_O,shifted} \quad (16)$$

$$\Delta E_C = E_{RDEWH_C} - E_{RDEWH_C,shifted} \quad (17)$$

where E_{RDEWH_O} is the baseline energy drawn in an uncontrolled scenario for off-peak resistive storage water heaters, E_{RDEWH_C} is the baseline energy drawn in an uncontrolled scenario for continuous resistive storage water heaters, and $E_{RDEWH_O,shifted}$ and $E_{RDEWH_C,shifted}$ are the terms identifying energy drawn in an alternative energy use scenarios that shift the load.

In this case the total energy saved will be:

$$\Delta E = \Delta E_o + \Delta E_c \quad (18)$$

To illustrate the technical and economic potential of resistive domestic electric water heaters (RDEWH) as a demand flexibility resource, the following example applies the same logic used for the residential battery storage example. This calculation considers the thermal storage capacity, power intake, and the specific constraints of ‘solar soaking’ orchestration.

A household can use around 15% to 30% of its daily energy consumption just for water heating (Department of Climate Change, 2026).²³ A resistive or electric hot water storage system tends to be the least efficient in terms of energy use (unless powered by a PV system) and these units are available in around 50% of Australian households.

Based on the electricity benchmarks for 2020, a household of 1 person can use at least around 2919 kWh/year and a household of 5 people or more can use up to 11,554 kWh/year depending on the climate zone, with a rough average sitting at 6,760 kWh/year (Frontier Economics, 2020).²⁴ A consumption of 15 to 30% of the average amount would be equivalent to use around 1000 - 2000 kWh/year or 2.8 - 5.6 kWh/day. An Australian study of 410 households found that average household use of electricity for hot water is 6 kWh and that using daily excess PV energy for DEWH functioning can reduce the imported energy use of the DEWH by around 50% (Yildiz et al., 2021).

For a given set period of analysis (as per section 2.1), if a home’s storage water heater is assumed to be available 30% of the time during a period of 2.5 hours per day (an assumption of the average hours per event) and the effective load reduction per home (customer) per day is assumed to be 0.9 kW/home, then its Available Coincident Energy for load reduction per day will be: $2.5 \text{ h} \times 0.3 \times 0.9 = 0.675 \text{ kWh}$.

The yearly ACE, or ACE available during a period such as ‘acute constraint’ as energy reduction per home per year, is calculated as the product of constrained energy days per year (20 days) and the Available Coincident Energy (ACE) per home (for load reduction) available per day: $\text{ACE} = 0.675 \times 20 = 13.5 \text{ kWh}$.

5.4.6 Facilitation Costs

Incentives

For modelling, the annual incentive costs (AUD/year) can be represented as:

$$C_{inc,RDEWH} = N \times I \quad (19)$$

where N is the number of upgrades delivered under the program in the year and I is the average incentive per upgrade.

Incentives can cover DER enablement costs (where enablement is needed) for a storage water heater and these costs at a minimum would need to cover the installation of a control device (a timer or a diverter) and to ensure the system is on a dedicated electrical circuit. For solar soaking,

²³ An average for the country sits at 23% (Australian Government, 2020).

²⁴ An average of the yearly values by state and climate zone that is not weighted for the population.

the assumption is that a diverter is installed, and an electrician is needed to install this, as well as to put the RDEWH on a separate circuit. These costs could be around \$1,650 and they are meant to cover a 10-year lifetime of the technology. If these costs are assumed to be fully covered by an incentive, then the value of the incentive per kWh of potential storage provided by the storage water heater used in the example above is equivalent to $\$1650/18.31\text{kWh} = \$90.11/\text{kWh}$ of energy storage capacity. As in section 5.1.6, this is a fixed, one-off incentive cost and the REDWH should operate for 10 years. Therefore, the annual incentive would equate to about \$9/kWh of storage capacity.

Again, to obtain a rough LCODF calculation (which excludes administrative and free riders' costs), we assume an upfront incentive of \$200, an interest rate of 7% and an analysis time horizon of 10 years. This yields an annualised incentive value approximated to around \$26.61. Considering a dispatch incentive of \$14 per annum, we can get a total incentive cost of around \$40. In this case the LCODF is $\$40/13.5 \text{ kWh}_{\text{PoA}} = \$2.97/ \text{ kWh}_{\text{PoA}}$.

Administrative costs

For RDEWH upgrades, administrative tasks include eligibility checks, verifying the installed product meets scheme product requirements, verifying installer licensing requirements, meeting pre-installation requirements, managing evidence of decommissioning and disposal, providing required consumer information, and retaining required records. The modelling formulation for RDEWH upgrade administration cost would be similar to those discussed in space cooling and heating upgrades (Essential Services Commission, 2025). For modelling purposes, administration costs can be represented as:

$$C_{ad,RDEWH} = Ad_{fixed} + N \times Ad_{var} \quad (20)$$

Where Ad_{fixed} covers program design, systems, and governance, and Ad_{var} covers per-upgrade processing, evidence checks, and audit/inspection sampling.

Administrative costs include orchestration and software subscription fees. Unlike standard (manual) 'off-peak' timers, solar soaking requires active communication between the smart meter, the water heater, and potentially a third-party aggregator. This orchestration can involve annual software subscription costs or 'platform fees' to maintain the connection to Virtual Power Plant (VPP) infrastructure or a Home Energy Management Systems (HEMS) (Rheem, 2024).

Free riders cost

In the NSW statutory review by the Department of Climate Change Energy the Environment and Water (DCCEEW) (2025), estimated energy savings were reduced by 13% to account for the net rate of free riders and spillovers. On this basis, the free rider cost can be assumed at 13% of total incentive costs.

5.4.7 Resource Potential

As also noted in section 6.3, electric resistance water heaters offer high potential for flexible load control but have relatively low energy efficiency, whereas heat pump water heaters deliver much higher efficiency but typically provide less operational flexibility. A practical way to capture both

system benefits is to deploy different technologies by context, prioritising efficiency in some settings and flexibility in others (Roche et al., 2023).

One of the factors affecting technical potential is that not all models of heat pump water heaters are suitable for outdoor installation in climates where winter ambient temperatures regularly fall below $\sim 5^{\circ}\text{C}$. Moreover, many systems include a resistance booster element to maintain output in colder periods or during high draw events. This can reduce realised seasonal efficiency if boosting is frequent especially in regions where winter PV output is low and at times of extreme weather with low PV output and likely space heating demand.

Low controlled load tariffs and (high) solar feed-in tariffs can act as a disincentive for DF activation, with one estimate considering that discounts for tariffs applied to charging this technology may need to be more than 30% below standard uncontrolled tariffs (Roche et al., 2023).

5.4.8 Data

Table 8 Storage water heaters costs and parameter data (initial exercise for data sources identification)

Parameter	Unit	Type	Source
Tank volume	L	Performance	Roche et al. (2023), BIS Oxford Economics (2018)
Tank's SOC	%	Performance	RACE for 2030 (2025)
Element rating	kW	Performance	Roche et al. (2023)
Purchase and installation costs	\$/L	CAPEX	(Roche et al., 2023), (Same Day Hot Water Service, 2025)
Operating costs	\$	OPEX	RACE for 2030 (2025)
Thermal capacity	kWh_th	Performance	RACE for 2030 (2025)
Coefficient of performance	-	Performance	Roche et al. (2023)
Average peak demand created by uncontrolled EHW	kW	Performance	Ausgrid (2016)
Standby losses	kWh_th/day	Performance	Manufacturer data, GEMS database
DR enablement device cost	\$/device	CAPEX	Program docs, Associates (Energy Efficient Strategies with George Wilkenfeld & Associates and Common Capital, 2020), RACE for 2030 (2025)
Communications cost	\$/site-year	OPEX	Program docs, Associates (Energy Efficient Strategies with George Wilkenfeld & Associates and Common Capital, 2020), RACE for 2030 (2025)
Controlled-load windows	time window	Constraint	DNSP tariff guides, RACE for 2030 (2025)
Event parameters	events/season; h	Program	RACE for 2030 (2025)

Customer incentive	\$/event or \$/year	Program	NSW Government (2025c)
Maintenance costs	\$/year	OPEX	RACE for 2030 (2025)
Opt-out rate	%	Program	Ausgrid (2022a), Ausgrid (2016)
Projection data (cost and installed capacity)	Number of units/year, \$	Meta	Roche et al. (2023)
Load profiles	%/hour of day	Performance	RACE for 2030 (2025), Ausgrid (2016)
Efficiency rating	Rate 1-10	Performance	CSIRO (2025a)
Estimates of hot water systems in buildings	Number of units	Meta	Goldsworthy et al. (2021)

5.5 Solar pre-cooling and pre-heating

5.5.1 Resource description

Heating and cooling are a significant component of the Australian residential energy profile, accounting for 20-50% of the total energy used in the existing homes (Department of Climate Change, 2023). Solar pre-cooling and pre-heating (SPC/H) is a demand-side management strategy that utilises a building’s thermal mass as a storage medium to shift electricity consumption from peak periods to times of abundant solar PV generation. For households with PV systems, by operating reverse-cycle air conditioners (heat pumps) during the middle of the day—when rooftop solar PV output is highest and wholesale prices are often lowest—occupants can ‘charge’ the internal environment by lowering or raising the temperature of structural elements like concrete slabs, walls, and furniture. However, if the building is thermally poor much of this pre-heating and cooling energy can be wasted. Furthermore, this strategy is equally applicable to households without on-site solar PV, as it enables the local absorption of surplus generation from neighbouring installations, thereby mitigating regional grid congestion and supporting network-wide stability. If the building is thermally performant, thermal inertia can allow the building to remain within a comfortable temperature range during the evening peak (typically 4 pm to 9 pm), reducing the need for grid-imported electricity when the network is most constrained.

Compared an electric element heater, an efficient reverse-cycle heating device can draw 6 times less energy (5205 kWh compared to 868 kWh) and therefore be 6 times cheaper to run (ACT Government, n.a.). A California trial suggested that pre-cooling could have a major impact on annual peak residential energy demand for air-cooling, shifting between 75%-84% of this demand (Wilmot et al., 2021). Nonetheless, RCAC efficiency and output capacity declines in more extreme weather, both hot and cold.

5.5.2 Capital Costs (CapEx)

The capital costs (CapEx) for Solar pre-cooling and pre-heating as a demand flexibility resource come from the installation of energy efficient cooling or heating devices, such as reverse cycle

systems, from the automation and control layer required to shift the load, as well as from any physical enhancements that increase the building's thermal storage capacity and reduce heat gains/losses.

In the context of the FlexCost methodology, the capital costs for this option are categorised into three primary areas:

1. Incremental Hardware and Controller Costs

If the building does not have a modern reverse-cycle air conditioner, the purchasing costs of a device is part of the CapEx.

If a building already possesses a modern reverse-cycle air conditioner, the CapEx for demand flexibility is limited to the cost of the smart interface.

- Smart controllers and gateways (smart thermostat): to enable remote or automated scheduling based on solar production, an external controller may be required.
- DRED-Enabled Inverters: For new installations, the incremental cost of selecting a unit with a Demand Response Enabling Device (DRED) or native IEEE 2030.5 compatibility it is a critical requirement for participating in formal DNSP demand-response programs.

2. Control System Integration and Commissioning

SPC/H requires professional setup to ensure the HVAC system 'talks' to the solar inverter or a Home Energy Management System (HEMS).

- HEMS Hub Installation: A central orchestrator is often needed to monitor real-time solar export and trigger the HVAC unit.
- Specialist commissioning: Labour costs can involve a technician or energy auditor setting up the 'thermal charging' schedule (e.g., pre-cooling the house to 19°C between 11 am and 3 pm). However, manual activation of devices is possible with SMS reminders to turn their devices on or off (Wilmot et al., 2021).

3. Thermal Envelope Enhancements

The other 'resource' in SPC/H is the building's thermal mass. To increase the duration for which a house can 'hold' its pre-cooled temperature, capital may be additionally invested in thermal enhancements to the building envelope such as:

- Insulation and draught sealing: Upgrading ceiling insulation or installing high-quality weather-stripping acts as a 'thermal battery upgrade'.
- Window shading: Capital outlays for external blinds or awnings reduce the 'solar heat gain' that the pre-cooling system must fight, thereby extending the effectiveness of the shifted load.

An air-conditioning unit can have a lifetime of 10-15 years.²⁵

5.5.3 Operating and Maintenance Costs (OpEx)

Operating costs are incurred when the household runs their heater or cooling device before the peak demand period. However, in order for the scheme to be attractive to participants, these costs need to be offset through an advantageous tariff or other incentive structure. So, additional operating costs for the scheme are assumed to be nil.

The realised efficiency of thermal assets is contingent upon the maintenance regime. The presence of clogged filters has been shown to significantly degrade unit performance by reducing output capacity and increase energy consumption. The realised efficiency of heat/cold distribution, thermal assets is contingent upon the maintenance regime. In practice, however, regular maintenance is often overlooked, leading to degraded performance and increased energy consumption as the default operational state. From a modelling perspective, this can be handled in two ways: either as a maintenance expenditure (to maintain optimal performance) or as a performance derating factor (to reflect real-world degradation). Standard market service benchmarks often fail to capture the reality of the post-installation maintenance gap, where a lack of follow-up from installers results in sub-optimal asset performance over time. Ensuring the assets remain 'grid-ready' may require administrative overheads, such as automated maintenance reminders or verification checks. These 'soft costs' of program administration may need to be considered and included in the calculations. However, when detailed data is absent in practice, OpEx may be assumed or estimated as a fixed value, a percentage of the total capital cost, using standard market service and warranty benchmarks (Gamborg & Rasmussen, 2025; Thrän et al., 2025; Zang et al., 2025).

5.5.4 Associated System Costs

Associated network and system costs for integrating SPC/H as a demand flexibility service, like for many of the technologies presented in this report, are driven by the requirement for digital visibility, coordination infrastructure, and regulatory compliance. These expenditures are incurred by DNSPs and aggregators to ensure that shifted air conditioning loads do not compromise grid stability or exceed local transformer capacities.

DNSPs face significant capital and operational expenditures to manage the technical impact of mass load-shifting on the low-voltage network, but this would not be additional if similar coordination functionality were installed for EV management or battery management.

- **Implementation of Dynamic Operating Envelopes (DOEs):** DNSPs must invest in software modules and algorithms to manage DOEs, which communicate real-time network capacity to residential assets.

²⁵ Source: <https://www.choice.com.au/shopping/consumer-rights-and-advice/your-rights/articles/how-long-should-your-appliances-last#Heating%20and%20ventilation>

- **Data Sharing and Infrastructure:** Establishing the data sharing arrangements necessary for DNSPs to understand the interaction between network constraints and dispatch signals is a major system cost.
- **Low-Voltage Visibility:** DNSPs can require upgraded monitoring and information and communication technology (ICT) infrastructure at the substation level to measure the impact of shifted thermal loads
- **Fixed Implementation Costs:** These represent upfront investments in regional or national frameworks that are ‘not tied to the level of benefits realised’ by participating households.

5.5.5 Resource Availability and Available Coincident Energy

For modelling total annual electricity savings from solar pre-cooling and pre-heating: load shifting, the energy savings would come from changing the load profile of a building resulting in a reduction in energy consumption in the home:

$$\Delta E_{cooling} = E_{cooling_b} - E_{pre-cooling_{shifted}} \quad (21)$$

$$\Delta E_{heating} = E_{heating_b} - E_{pre-heating_{shifted}} \quad (22)$$

where $E_{cooling_b}$ is the baseline energy drawn in an uncontrolled scenario for cooling a building, $E_{heating_b}$ is the baseline energy drawn in an uncontrolled scenario for heating, and $E_{pre-cooling_{shifted}}$ and $E_{pre-heating_{shifted}}$ are the terms identifying energy drawn in an alternative energy use scenarios that shift the load. In this case the total energy saved will be:

$$\Delta E = \Delta E_{cooling} + \Delta E_{heating} \quad (23)$$

The BAU for peak cooling or heating can vary based on climate zone / location in Australia, however generally they tend to coincide with the evening peak use of energy and cold mornings. To enable the pre-cooling and pre-heating, either solar soaking or cheap/free energy from the grid should be available to the home.

To demonstrate the costs calculations around solar pre-heating and pre-cooling as a demand flexibility resource, the following examples apply the same logic used for residential batteries and other technologies. However, given pre-heating and pre-cooling functions may draw different amounts of energy, two different examples are given.

Unlike a battery, where capacity is fixed by chemical limits, the ‘capacity’ of SPC/H is defined by the building’s thermal mass, heat gain/loss and the efficiency of the reverse-cycle air conditioner. An efficient reverse-cycle device can draw six times less energy than an electric element heater (ACT Government, n.a.).

Summer example of cost calculations: Solar pre-cooling

A reverse-cycle air conditioner with a cooling rated capacity of 2.5 kW, would have a different heating rated capacity, e.g. 3.2 kW.²⁶ At the same time, the thermal work performed (or the power rating for cooling or heating) and the actual power consumed are two different figures. For

²⁶ This example is based on Mitsubishi electric MSZ units (indoor product code) (Mitsubishi Electric, 2026).

cooling, a 2.5 kW split system can draw around 0.3 - 0.9 kW or on average 0.65 kW per hour. For a higher rated item, e.g. of 5.0 kW, the input power can be higher, such as 1.28 kW.²⁷

As an illustrative example, similarly to previous sections, if a customer's air conditioner is assumed to be available 60% of the time during a period of 2.5 hours per day (an assumption of the average hours per event) and the constrained period's (e.g. in an acute constraint period) effective load reduction per home (customer) per day is assumed to be 1.2 kW/home (roughly aligned with the 5.0 kW unit's draw), then its Available Coincident Energy for demand reduction per day will be: $2.5 \text{ h} \times 0.6 \times 1.2 = 1.8 \text{ kWh}$.

The yearly ACE, or ACE available during the period of analysis as energy reduction per home per year, is calculated as the product of constrained energy days per year (20 days) and the Available Coincident Energy (ACE) per home (for demand reduction) available per day: $\text{ACE} = 1.8 \times 20 = 36 \text{ kWh}$.

Winter example of cost calculations: Solar pre-heating

In this scenario, the air conditioner is run during the midday solar window (e.g., 10 am to 2 pm) to store heat in the building's structure, thereby reducing or eliminating the need for grid-imported heating during the 5 pm to 9 pm winter peak.

Using a similar logic to the above, but modifying the assumed period effective load reduction per home (customer) per day to 0.8 kW, ACE per home per day is 1.2 kWh and the year figure amounts to 24 kWh.

5.5.6 Facilitation Costs

Incentive Costs

To ensure the financial feasibility of solar pre-cooling and pre-heating (SPC/H), the disparity between the evening peak tariff and the solar feed-in tariff (FiT) must be significant. In one trial incentives were offered to people to participate in a demand response program based on a one-off cash incentive to join, however to leave the program the household has to pay a penalty in the form of participants paying for an electrician to disable the control device (Wilmot et al., 2021). Potential other incentives offered include subsidies for other energy savings or energy control technologies (e.g. smart control devices).

Summer example of LCODF calculation: Solar pre-cooling

Using the ACE ratio calculated in the previous section, this example derives the facilitation cost per year, based on an incentive only assumption, and calculates a demonstrative LCODF value.

If an upfront incentive is assumed to be \$200, the interest rate is assumed to be 7% and the analysis time horizon of 10 years, the annualised incentive value can be approximated to around \$26.61. Considering a dispatch incentive of \$36 per annum, we can get a total incentive cost of around \$63. In this case the LCODF for this specific period of analysis is $\$63/36 \text{ kWh} = \1.74 .

²⁷ According to Choice (2024), but these values can vary according to appliances and higher values are possible. The higher cooling rated capacity is based on the Rinnai – J Series 5.0 kW Reverse Cycle Split System (Rinnai, 2026).

Winter example of LCODF calculation: Solar pre-heating

Similar to the previous example, but instead assuming a different annual dispatch incentive, such as \$24, the LCODF would be \$2.11.

Administrative Costs

Aggregators and system operators incur costs to facilitate the market participation of dispersed residential air conditioning units.

- **AEMO Framework Implementation:** The Australian Energy Market Operator (AEMO) has estimated an initial cost of \$29 million to implement the national framework for integrating price-responsive resources, which includes the logic for managing thermal loads like SPC/H.
- **Virtual Power Plant (VPP) Facilitation:** Aggregators incur annual facilitation costs. Costs incurred for EV orchestration could be applicable for this type of facilitation costs.
- **Customer Support and Technical Maintenance:** Ongoing operational support to manage customer enquiries and technical troubleshooting will be needed and this can be costlier than physical or software infrastructure.
- **Measurement and Verification (M&V):** Aggregators must invest in systems to capture and process interval-based data (e.g., 5-to-30-minute intervals) to verify that the cooling or heating load was successfully shifted to the intended solar-soaking window.

Free Rider Costs

Existing solar PV households are the most common potential free riders. These ‘prosumers’ are often highly price-sensitive and motivated by energy independence. They may already use their excess solar to pre-cool their homes during the day to avoid high evening peak tariffs, even without a formal utility program.

5.5.7 Resource Potential

Parameters affecting technical potential or that influence the availability of upgrades include:

- **Thermal Mass and Envelope Efficiency:** The capacity of a building to retain thermal energy depends on its construction materials and insulation levels (e.g., NatHERS star rating); higher thermal mass and better airtightness extend the ‘discharge’ duration, allowing for a more significant shift away from evening peaks.
- **HVAC Control Intelligence and Interoperability:** Availability is limited by the requirement for the presence of smart controllers or Demand Response Enabling Devices (DREDs) that can interpret grid signals or solar-soak triggers; without standardised communication protocols, automated orchestration remains technically difficult.
- **Solar PV Generation Profiles:** The temporal alignment between local solar production and the pre-cooling/pre-heating window determines the degree of ‘self-consumption’; if cloud cover or shading reduces midday output, the system may inadvertently draw from the grid at a higher cost.

- **Ambient Temperature and Heatwave Intensity:** The Coefficient of Performance (COP) of heat pumps varies with outside conditions; also, extreme heatwaves can saturate the thermal storage capacity of a building more quickly, reducing the effectiveness of pre-cooling as the evening progresses.
- **Climate:** Brisbane has been found to be more suitable for SPH than Melbourne and Adelaide for SPC (Wilmot et al., 2021).

In addition to factors which affect technical potential, a host of financial, social, and behavioural factors can act as barriers to materialising the technical potential of this resource: tariffs need to lead to financially attractive outcomes, temperature tolerance of occupants²⁸, occupancy, public perception, trust, awareness (Wilmot et al., 2021).

5.5.8 Data

Table 9 Solar pre-cooling and pre-heating costs and parameter data (initial exercise for identification of data sources)

Parameter	Unit	Type	Source
Conservation Load Factor (CLF)	-	Meta	Department of Resources Energy and Tourism (2011); Oakley Greenwood (2012); Strategy. Policy. Research. (2019)
COPs and EERs	-	Performance	Energy Rating (2025)
Heating & Cooling Load in Different Cities	%	Performance	Belusko et al. (2019)
Star rating vs annual consumption	kWh/year	Performance	Belusko et al. (2019)
consumption of electrical end-uses in reference buildings	kWh/year	Performance	Belusko et al. (2019)
Cost of cooling and heating devices and installation	\$	CAPEX	Choice (2023)
Cost projections	\$, \$/kW year,	CAPEX	ACIL Allen (2026)
Running costs	\$	OPEX	Government of South Australia (2025)
Administration costs	\$	Facilitation Costs	Essential Services Commission (2026b); Victoria State Government (2025e)
Number of scheme participants and certificates	unit	Meta	Department of Climate Change Energy the Environment and Water (DCCEEW) (2025)

²⁸ A wider range of acceptable indoor temperatures increases the volume of energy that can be shifted without causing discomfort or manual intervention

Space conditioning average energy use per household per source per region	kWh/dwelling	Meta	Rajagopalan (2023)
Discounts for space heating and cooling upgrades	\$	Facilitation Costs	Victoria State Government (2026a)
Upgrade & Intention to purchase: Heating and efficiency	%	Meta	Energy Consumers Australia (ECA) (2023)
Products Ownership: Heating & Cooling	%	Meta	Energy Consumers Australia (ECA) (2023)

5.6 Pool pumps and pool heaters (load shifting)

5.6.1 Resource description

Residential swimming pool pumps and heaters potentially represent a highly flexible ‘deferred’ load that can be significantly shifted without impacting the primary utility of the asset. Because filtration and heating cycles do not require instantaneous energy consumption to maintain water hygiene or temperature, the entire load can be moved to periods of high solar generation (solar soaking) or switched off entirely during system constraints. This flexibility is supported by the pool’s thermal and chemical inertia, where a cessation of operation for several hours does not result in a meaningful degradation of water quality or a noticeable drop in temperature. However, technical potential may be limited by the number of set hours required for a pool to be kept in working order. The most commonly sold pool pumps in Australia in 2015 were the single speed 3-star rating ones (Department of the Environment and Energy, 2017). The input power of such a pump can be estimated as: $P = 2,981.82 \times \exp(-0.3634 \times \text{star}) = 1,002 \text{ W}$ (Goldsworthy et al., 2021), which can be rounded down to 1,000 W. Annual energy use estimates for pool pumps vary around the 4.65PJ to 5.4 PJ figure excluding pool heating and up to 8PJ including heating (for studies from 2020 onwards)(Goldsworthy et al., 2021). In kWh per year, the annual energy consumption for an average household has been estimated at 1850 kWh per pump and for the state of Victoria at 3.2% of the total residential mains electricity consumption(Sustainability Victoria, 2016). One study estimates that residential pool pumps could provide 170 MW as emergency DF resource and 450 MW coincident with minimum demand (Goldsworthy et al., 2021).

5.6.2 Capital Costs (CapEx)

Pool pump DF activation can be achieved with solar diverters (like for resistance electric water heaters) and home energy management systems (Roche et al., 2023). Adding DR capability to products such as pool has been generically evaluated at \$31 per product (E3, 2019).

However, the CapEx for this demand flexibility resource is primarily composed from costs for the control layer rather than the physical appliances themselves. These costs include:

- Smart controllers/timers: Retrofitting existing pumps with Wi-Fi-enabled timers or smart plugs.

- HEMS integration: For more advanced orchestration (e.g., VPP participation), the cost of a central gateway and professional commissioning may need to be covered.
- VSD or multi-speed upgrades: In the case of single-speed pump being replaced with a variable-speed drive (VSD) to improve both efficiency and flexibility, an additional incremental cost can be incurred.

5.6.3 Operating and Maintenance Costs (OpEx)

Operational costs in DF mode include ongoing ‘soft costs’ that do not exist in a BAU environment:

- Software and orchestration fees: Participation in a third-party orchestration program or VPP often involves an annual subscription or platform fee.
- Connectivity and technical support: Maintaining the ‘firmness’ of the resource requires consistent internet connectivity. Households may face ‘transactional’ costs in the form of time or professional support to troubleshoot Wi-Fi dropouts or communication errors between the charger/pump and the aggregator.

For pool heaters, shifting the cycle to midday may result in slightly higher thermal losses if the water is heated significantly above ambient temperatures earlier in the day, though this is expected to be offset by the lower cost of solar-derived energy.

A trial indicated that as many as 80% of households may be doing their own regular pool maintenance (Woolcott Research Engagement, 2016). No additional mechanical wear is assumed, so the costs for additional maintenance of the pool pumps or pool heaters are considered nil.

5.6.4 Associated System Costs

Associated system costs for integrating pool pumps and heaters as a demand flexibility (DF) resource involve the ‘hidden’ expenditures required to transition these assets from standalone appliances to grid-responsive resources. For Distribution Network Service Providers (DNSPs) and System Operators (AEMO), these costs are driven by the need for digital visibility, technical orchestration, and the management of ‘secondary peaks or voltage fluctuations.

DNSPs incur costs to manage the physical and logical constraints of the low-voltage (LV) network. To treat pool pumps as a firm resource, DNSPs must invest in ICT and sensors at the local transformer level. Costs incurred would be similar as noted in the previous sections for:

- implementing ‘dynamic voltage management systems’ or low-voltage visibility tools.
- implementation costs for software modules and algorithms required to manage Dynamic Operating Envelopes (DOEs). These are generally considered low-cost/high value compared to physically expanding or upgrading the electricity network but still require significant internal engineering and ICT capital outlays.
- the administrative labour to process flexible connection agreements and verify that pool controllers meet Australian standards is a documented system cost.

For pool pumps and pool heaters to effectively participate in load shifting and solar-soaking programs, the system operator and network providers require reliable, interval-based data capture (e.g., 5-to-30-minute intervals) to verify that demand has been successfully moved to optimal periods. Although less intensive than the sub-second requirements for ancillary services, the costs associated with establishing data sharing arrangements necessary to synchronise these shifts with network constraints - such as Dynamic Operating Envelopes - remain a significant fixed cost for aggregating small residential assets. These expenditures represent a substantial upfront investment that is not intrinsically tied to the actual volume of demand flexibility realised.

5.6.5 Resource Availability and Available Coincident Energy

For modelling annual electricity savings from pool pumps and heater load shifting, the impact is derived from re-aligning the operational schedule to coincide with renewable generation and avoiding consumption during peak price or grid-constrained intervals:

$$\Delta E = E_{PP_b} - E_{PP_s} \quad (24)$$

Where E_{PP_b} is the baseline energy used for running pool pumps in an uncontrolled scenario, E_{PP_s} is the total energy shifted during constrained energy periods by using pool pumps and heaters for load shifting grid services.

A pool pump on average has been estimated to use around 1,350 kWh per year, or close to 18% of a household's annual energy budget (Department of the Environment and Energy, 2017). An estimate of the projected energy use by efficiency star rating shows a range from above 3,000 kWh, for a 1-star rated pool pump, to around 750 kWh, for a 5-star rated pool pump (Department of the Environment and Energy, 2017). Efficiency regulation and measures are likely to reduce pool pump and pool heaters energy use over time through the installation of increasingly more efficient pumps.

To illustrate the potential for a pool pump to provide energy flexibility services to the grid, a simplified example of Available Coincident Energy calculations is presented here and is similar to previous sections' examples. If a customer's pool pump with average consumption (as estimated in 2017) was assumed to be available 70% of the time during a constrained period of 2.5 hours per day (an assumption of the average hours per event) and the effective load reduction per home (customer) per day is assumed to be 0.5 kW/home, then its Available Coincident Energy for load reduction per day will be: $2.5 \text{ h} \times 0.7 \times 0.5 = 0.875 \text{ kWh}$.

The yearly ACE, or ACE available during a set period of analysis as energy reduction per home per year, is calculated as the product of constrained energy days per year (20 days) and the Available Coincident Energy (ACE) per home (for load reduction) available per day: $\text{ACE} = 0.875 \times 20 = 17.5 \text{ kWh}$.

5.6.6 Facilitation Costs

Incentive Costs

Incentive costs for swimming pool pumps and heaters in Australia are primarily aimed at overcoming the capital barrier of smart orchestration and encouraging the shift of load away from

peak periods. These incentives are structured as either upfront capital subsidies for hardware or ongoing performance-based credits for grid participation.

As above, if an upfront incentive is assumed to be \$200, the interest rate is assumed to be 7% and the analysis time horizon of 10 years, the annualised incentive value can be approximated to around \$26.61. Considering a dispatch incentive of \$9 per annum, we can get a total incentive cost of around \$35.61. In this case the, a the LCODF is $\$35.61/17.5 \text{ kWh} = \2.04 .

Administrative Costs

Part of the administrative costs will be incurred for control infrastructure and automation level. Availability is constrained by the presence of smart timers or Home Energy Management Systems (HEMS); without automated orchestration, the 'firmness' of the resource relies on manual intervention, which typically results in lower reliability during network events.

System operators and aggregators incur costs to bridge the gap between individual households and the wholesale electricity market. The administrative cost would relate to a third-party aggregator (VPP Platform maintenance) to manage an orchestrated fleet of residential assets.

Free Rider Costs

Free ridership in pool pump programs is potentially high due to existing consumer behaviours. Many pool owners already use simple mechanical timers to set their filtration cycles to 'off-peak' or 'midday' periods to save on energy costs independently of a formal demand flexibility program. Similar to V2G free riders who accept subsidies but opt-out, pool owners may accept smart-controller subsidies but override the 'off' command during a network event if they prioritize immediate water clarity (e.g., before a social event), reducing the firmness of the estimated 100% load-flexibility.

5.6.7 Resource Potential

Parameters affecting technical potential or that influence the availability of upgrades at particular times or scale include:

- **Filtration and hygiene requirements:** The technical potential may be bounded by the minimum daily turnover rate required to maintain water health; pumps must operate for a set number of hours (determined by pool volume) which limits the total duration they can remain 'off' during prolonged grid events.
- **Pump technology and power draw:** The magnitude of the flexible resource depends on the pump type; traditional single-speed pumps offer a higher 'lump' of shedable load, whereas modern variable-speed pumps, while more efficient, provide a smaller but more granular resource for fine-tuned orchestration
- **Seasonal utilisation profiles:** Technical potential is likely to vary significantly by season, particularly for pool heaters. While filtration is a year-round requirement, the heating load is highly coincident with shoulder seasons and winter, altering the scale of the available resource across the annual cycle.

5.6.8 Data

Table 10 Pool pumps and pool heaters costs and parameter data (initial exercise for data sources identification)

Parameter	Unit	Type	Source
Estimates of pool pumps in buildings	Number of units	Meta	Goldsworthy et al. (2021)
Operating hours	Hours/day	Constraint	Goldsworthy et al. (2021)
Annual energy consumption	kWh	Performance	Sustainability Victoria (2016)
Pool pump efficiency (single and multi-speed)	%	Performance	Woolcott Research Engagement (2016)
Pump power consumption	kW	Performance	Goldsworthy et al. (2021)
DR enablement device cost	\$/device	CAPEX	(E3, 2019)
Projected sale and energy use	Unit/year, GW, TWh	Meta	DCCEE (2018, 2023a); NERA Economic Consulting (2022)
Percentage of replacement per year	Unit/year	Meta	DCCEE (2018)

6 Energy efficiency technologies

Key points

It is proposed that FlexCost should study the following energy efficiency technologies:

- Space heating and cooling upgrades
- Insulation and thermal efficiency retrofits
- Heat pump water heaters
- Retirement and replacement of inefficient appliances

Just as the previous section describes the cost and characteristics of demand flexibility technologies, this section considers energy efficiency technologies descriptions and cost components to be addressed in the first FlexCost model and report. Please note that all figures presented below are purely illustrative and should not be considered as definitive or reliable.

Key parameters and features to be considered in analysis for each technology below.

- Electricity demand, consumption and impact on peak demand (with and without 'facilitation'.)
- Capital, installation and operating cost.
- Potential facilitation/incentive costs, program administration costs.
- Availability, diversity, adoption rates, free rider (and free driver) rates.
- Relevant technology-specific parameters: Round trip efficiency, coefficient of performance, rebound effect, etc

The definition of residential and non-residential buildings is based on the classification provided by Volume One of the Building Code (Australian Building Codes Board, 2025). The section assesses equipment efficiency upgrades within the existing end-use fuel (in particular, electricity). Therefore, where discussing space heating and heat pump water heater (HPWH) upgrades, it focusses specifically on:

1. space heating upgrades where lower-efficiency electric reverse-cycle systems are replaced with higher-efficiency units, and
2. HPWH upgrades where electric resistance storage water heaters are replaced with air-source heat pump water heaters.

Gas-to-electric replacements are not included because they are primarily fuel-switching (electrification) measures with different baselines and cost components and are therefore treated as a separate class of intervention rather than an efficiency upgrade.

6.1 Space heating and cooling upgrades

6.1.1 Resource description

Space heating and cooling is a major source of household energy use in Australia, with its contribution to total household energy use varying significantly for different locations and climate zones (Frontier Economics, 2020). Reported estimates range from 20% and 50% of total home energy use (Department of Climate Change, 2023). Resources for upgrading space heating and cooling cover upgrades to fixed space heating and cooling systems that reduce energy required to maintain indoor comfort. AEMO reports that summer peak demand during extreme weather is mostly dominated by residential air conditioning loads (Strategy. Policy. Research., 2019). Therefore, higher-efficiency units reduce demand when the system is most constrained.

For example, this includes replacing older or inefficient electric heating or cooling equipment (such as older reverse-cycle units) with a more energy-efficient reverse-cycle air conditioner. A correlation analysis between appliance star rating and efficiency shows that moving from a 1-star to a 6-star reverse-cycle system increases Coefficient of Performance for heating (COP) from 3.18 to 5.46 and Energy Efficiency Ratio for cooling (EER) from 3.18 to 5.38 (Belusko et al., 2019), which is equivalent to roughly 40-42% less electricity for the same delivered heating or cooling output ²⁹.

6.1.2 Capital Costs (CapEx)

Installed costs vary by system type (split vs ducted), capacity, number of indoor units, and installation complexity (including any electrical upgrade needs). For modelling costs, indicative ranges can be found in sources given in

²⁹ The older star ratings may not be directly comparable with current winter or cold-zone heating star ratings. Under the current scale, even efficient units may receive more modest winter heating ratings than would be expected under the previous label format.

Table 11. Replacing an existing split-system with a new unit in the same locations is often lower-cost than a first-time installation because - in many cases - existing pipe routes may be reused and replacement may not require new electrical work. Because upfront prices can differ for different efficiency levels (with lower-priced models often being less energy-efficient), CapEx assumptions should be aligned to the intended efficiency tier, using the Australian Zoned Energy Rating Label (Energy Star, 2025) to define the target performance (seasonal efficiency by climate zone). For annualising CapEx, a residential air conditioner life of around 15-20 years can be a practical assumption for the annuity calculation.

6.1.3 Operating and Maintenance Costs (OpEx)

From Table 4, for energy efficiency measures, OpEx is commonly assumed to be nil (i.e., no additional fuel cost is required to ‘deliver’ the conserved energy), with the main relevant OpEx item being any incremental maintenance and servicing. For space heating and cooling upgrades, an OpEx item is an annual maintenance allowance, for example:

$$C_{op,H\&C} = c_{service} \times f_{service} \quad (25)$$

Where $c_{service}$ is the cost of a routine service and $f_{service}$ is the service frequency.

Maintenance affects realised efficiency. For example, dirty filters can significantly reduce unit efficiency, and cleaning or replacing clogged filters can lower energy consumption. For modelling, this can be treated either as:

- an explicit maintenance OpEx item (as above), and/or
- an availability or performance adjustment where older units deliver less of the expected efficiency improvement.

Some studies estimated OpEx using market service or warranty subscriptions and considered OpEx as a fixed proportion (e.g., 2.4%) of the investment cost for heating units (Gamborg & Rasmussen, 2025).

6.1.4 Associated System Costs

For space heating and cooling upgrades (an energy efficiency resource), associated network costs are assumed to be nil.

6.1.5 Resource Availability and Available Coincident Energy

Because air conditioning loads are strongly weather-dependent and can dominate peak conditions, the coincidence of energy reduction with system constraint periods (see Section 0) is usually high for this technology.

For modelling annual electricity savings from an efficiency-only upgrade (same delivered service):

$$\Delta E_{heating} = E_{heating,base} \left(1 - \frac{COP_{base}}{COP_{new}} \right) \quad (26)$$

$$\Delta E_{cooling} = E_{cooling,base} \left(1 - \frac{EER_{base}}{EER_{new}} \right) \quad (27)$$

$$\Delta E_{annual} = \Delta E_{heating} + \Delta E_{cooling} \quad (28)$$

6.1.6 Facilitation Costs

Incentive Costs

An example of incentives that can support these upgrades is the Australian Government's \$1 billion Household Energy Upgrades Fund, which provides access to discounted finance through participating lenders for eligible household energy upgrades (Clean Energy Finance Corporation (CEFC), 2023). Other state energy efficiency programs supporting such upgrades include The NSW Energy Savings Scheme (ESS) (NSW Government, 2025a), Victorian Energy Upgrade (VEU) (Victoria State Government, 2025f), Retailer Energy Productivity Scheme (REPS) in South Australia (Essential Services Commission, 2021), and ACT's energy efficiency improvement scheme (EEIS) (ACT Government, 2012).

In these state and territory schemes, the air conditioner upgrade incentive is delivered as an upfront discount under the relevant schemes. The discount level is variable by system and installation (including administrative and compliance costs) (Essential Services Commission, 2026b; NSW Government, 2025a). For modelling, incentive costs (\$/year) can be represented as:

$$C_{inc,H\&C} = N \times I \quad (29)$$

Where N is the number of upgrades delivered and I is the average incentive per upgrade (net scheme-funded amount).

Administration Costs

Under the state and territory efficiency upgrade frameworks, administrative tasks include eligibility checks, verifying the installed product meets the program product requirements, verifying installer licensing requirements, meeting pre-installation requirements, managing decommissioning and disposal evidence, providing required consumer information, and retaining required records (Essential Services Commission, 2025). For modelling, administration costs can be represented as:

$$C_{ad,H\&C} = Ad_{fixed} + N \times Ad_{var} \quad (30)$$

Where Ad_{fixed} covers program design, systems, and governance, and Ad_{var} covers per-upgrade processing, evidence checks, and audit/inspection sampling.

Free Rider Costs

In the NSW statutory review by the Department of Climate Change Energy the Environment and Water (DCCEE) (2025), estimated energy savings were reduced by 13% to account for the net rate of free riders and spillovers (see also Section 5.2.6). Therefore, for modelling, free rider cost can be assumed at 13% of total incentive costs.

6.1.7 Resource Potential

Parameters affecting technical potential or that influence availability of upgrades at particular times or scale include:

- The remaining potential is lower where efficient models are already common.
- Contribution to constrained energy is realised only when heating/cooling is used. Therefore, benefits are concentrated in hot/cold periods.
- Lower running costs can lead to longer operating hours in practice.

6.1.8 Data

The required data to estimate cost of space heating and cooling upgrades has been included in the sources in Table 11

Table 11 Data sources for space heating and cooling upgrades.

Parameter	Unit	Type	Source
Conservation Load Factor (CLF)	-	Meta	Department of Resources Energy and Tourism (2011); Oakley Greenwood (2012); Strategy. Policy. Research. (2019)
COPs and EERs	-	Performance	Energy Rating (2025)
Heating & Cooling Load in Different Cities	%	Performance	Belusko et al. (2019)
Star rating vs annual consumption	kWh/year	Performance	Belusko et al. (2019)
consumption of electrical end-uses in reference buildings	kWh/year	Performance	Belusko et al. (2019)
Cost of cooling and heating devices and installation	\$	CAPEX	Choice (2023)
Running costs	\$	OPEX	Government of South Australia (2025)
Administration costs	\$	Facilitation Costs	Essential Services Commission (2026b); Victoria State Government (2025e)
Number of scheme participants and certificates	unit	Meta	Department of Climate Change Energy the Environment and Water (DCCEEW) (2025)
Space conditioning average energy use per household per source per region	kWh/dwelling	Meta	Rajagopalan (2023)
Discounts for space heating and cooling upgrades	\$	Facilitation Costs	Victoria State Government (2026a)
Upgrade & Intention to purchase: Heating and efficiency	%	Meta	Energy Consumers Australia (ECA) (2023)
Products Ownership: Heating & Cooling	%	Meta	Energy Consumers Australia (ECA) (2023)
Sales projection	Unit/year	Meta	DCCEEW (2023a)
% of units remaining in use over years	% per year	Meta	E3 (2024)

6.2 Insulation and thermal efficiency retrofits

6.2.1 Resource description

This resource includes retrofit measures that reduce heating and cooling electricity use by improving the thermal barrier of existing buildings. Measures include ceiling and roof insulation

top-ups, wall and underfloor insulation where feasible, double glazing, external shading, and basic sealing of gaps around external doors, windows and service penetrations.

In Australia, older homes built prior to the introduction of national minimum energy efficiency standards in 2003 have an average NatHERS rating of 1.8 stars, while most new builds are at 7 stars (CSIRO, 2025f). For illustration, a 7 star dwelling corresponds to approximately 34 MJ/m².annum in Brisbane, 52 MJ/m².annum in Perth, and 285 MJ/m².annum in Darwin, whereas a 2-star dwelling corresponds to approximately 139, 251, and 648 MJ/m².annum, respectively. In 2023-24, about 9 in 10 new homes used NatHERS for compliance, which helped generating more than 194,680 NatHERS certificates/reports (Nationwide House Energy Rating Scheme, 2025).

A national survey by the ECA reported that about 70% of renters avoid heating/cooling to save money and 36% report at least one form of insulation (Energy Consumers Australia (ECA), 2025). CSIRO estimates that moving from no insulation to well-insulated can reduce heating/cooling costs by around 45% or more (CSIRO, 2024c).

6.2.2 Capital Costs (CapEx)

CapEx includes the purchase and installation cost of insulation and building shell upgrades (materials and labour), plus any required access works and removal/reinstatement.

According to Australian Government (2024), the average NatHERS rating of existing homes is estimated to be less than 3 stars (out of 10). This suggests great potential for energy savings and improved thermal comfort, though achieving these gains would require high CapEx. Capital cost values for insulation and thermal efficiency retrofits can be retrieved from sources in Table 12.

6.2.3 Operating and Maintenance Costs (OpEx)

For measures such as insulation and building fabric improvements, incremental operating cost can be assumed to be nil. Moreover, routine servicing is generally not required for most of the insulation improvements. For example, Deloitte (2024) applied a 25-70 year effective lifetime for ceiling insulation when modelling benefits over time. There is an exception, however, for draught sealing. CSIRO reported that seals around frequently operated doors and windows may degrade relatively quickly, and therefore regular maintenance is required to maintain effectiveness (CSIRO, 2024a). An effective life of 7 years can be assumed for draught sealing measures (Deloitte, 2024). For simplified costing, an annual maintenance allowance for draught sealing can be represented as:

$$C_{op,draught} = \frac{CapEx_{draught}}{7} \quad (31)$$

6.2.4 Associated System Costs

For insulation and thermal efficiency retrofits (an energy efficiency resource), associated network costs are assumed to be nil.

6.2.5 Resource Availability and Available Coincident Energy

Coincidence between the timing of impact of insulation and thermal efficiency retrofit measures and constrained energy periods on the network is high, because increase in space-conditioning demand is highly weather dependent. For modelling, annual electricity savings (kWh/year) can be formulated as:

$$\Delta E = E_{HVAC,baseline} - E_{HVAC,retrofit} \quad (32)$$

6.2.6 Facilitation Costs

Incentive Costs

Incentives for insulation and thermal efficiency retrofits are delivered similarly to space cooling and heating upgrades examined before. The same energy efficiency upgrade schemes also support these measures. From early 2026, the Victorian Government is planning to introduce VEU discounts for ceiling insulation for eligible households, with estimated average bill savings of more than \$400 per year (and up to \$850 per year in health cost savings) for uninsulated or under-insulated homes (Victoria State Government, 2025c). For example, under the VEU, underfloor insulation, window replacement, and retrofit measures are eligible for both residential and non-residential customers, whereas weather sealing activities are only eligible for residential customers. Also REPS provides incentives for home insulation and draft sealing upgrades.

Administration Costs

Within a given scheme, the administration cost structure is mostly common for different energy efficiency upgrade activities.

Free Rider Costs

Same as the previous section 6.1.6 for space heating and cooling upgrades, free rider costs can be assumed to be 13% of total incentive costs.

6.2.7 Resource Potential

Parameters affecting technical potential, or that influence the availability of upgrades at specific times or at scale include:

- Benefits are higher in climates and seasons with larger indoor-outdoor temperature differences, and during periods when heating or cooling load drives system peaks.
- Identification of homes with unusually high winter and/or summer energy bills could increase and accelerate more cost-effective change.
- Measures with higher disruption, such as wall insulation and window replacement, are more likely to occur during renovations, which constrains annual uptake.
- Part of the efficiency improvement may be taken advantage of by the residents as increased comfort (such as longer operating hours or tighter temperature setpoints).

6.2.8 Data

Table 12 provides a list of sources required for estimating different cost components of insulation and thermal efficiency retrofit measures.

Table 12 Data sources for insulation and thermal efficiency retrofits.

Parameter	Unit	Type	Source
Insulation cost	\$ per dwelling	CapEx	Insulation Easy (2025); Rajagopalan (2023)
Cavity wall insulation costs	\$ per dwelling	CapEx	
Combined package cost	\$ per dwelling	CapEx	
Scheme administration costs	\$	Facilitation cost	COAG Energy Council (2019); ICANZ (2024)
Inspection/ assessment cost	\$	Facilitation cost	
Dwelling renovation rate	%	Meta	
Uptake rate	%	Meta	
Typical property specifications	-	Meta	
Rental proportion of housing stock (rate)	%	Meta	
Average dwelling Star rating per state	score	Meta	
Proportion of Dwellings with Insulation	%	Meta	ICANZ (2024)
Locations of Insulation for houses reporting insulation	% in each region	Meta	
Useful life of measures	Year	Meta	Deloitte (2024)
Energy rating vs heating and cooling load (different spatial resolutions)	mixed	Meta	CSIRO (2026b)
Weather sealing discounts	\$	Facilitation cost	Victoria State Government (2026c)
Window glazing discounts	\$	Facilitation cost	Victoria State Government (2026d)
Upgrade & Intention to purchase: Insulation	%	Meta	Energy Consumers Australia (ECA) (2023)
Products Ownership: Insulation	%	Meta	Energy Consumers Australia (ECA) (2023)

6.3 Heat pump water heaters

6.3.1 Resource description

Domestic hot water (DHW) is contributing to roughly 15-30% of household energy use and up to ~25% of household emissions (depending on grid fuel mix). Main household water heater types include electric resistance storage, electric heat pump, and gas systems. This section specifically focusses on upgrading electric resistance storage to electric heat pump as discussed in the above sections. Electric resistance storage units typically draw 2.4-5.0 kW while heat pump water heaters (HPWHs) units usually draw under 1 kW for the heat pump (with 2-5 kW possible when a resistance booster operates). HPWHs can use 30% of the energy of electric resistance water heaters (Department of Climate Change, 2026). Based on ACT Government (2026) cost comparison, the heat pump reduces annual running cost by \$957/year (a reduction of about 67%) relative to electric resistance, and by \$372/year (about 43.8%) relative to gas³⁰.

6.3.2 Capital Costs (CapEx)

For an upgrade from an existing electric resistance storage water heater to a HPWH, CapEx includes the installed cost of the new HPWH (equipment plus labour), together with any incremental plumbing and electrical works required to complete the replacement, and decommissioning and/or removal of the existing resistance unit. Installed costs vary significantly by tank size, integrated versus split configuration, siting/clearance constraints, and the extent of electrical and plumbing changes. Heat pump compressors generally require outdoor air access, which can force relocation or additional works compared with a like-for-like resistance tank replacement.

Victoria State Government (2025b) reports that, before incentives, the installed cost of water heaters can range from \$2,500 to \$7,500. HPWHs required to carry at least a 5-year warranty under the VEU program. More details on the capital costs can be found in sources listed in

³⁰ Depending on system type, as storage gas systems can have substantial standby losses, unlike instantaneous systems.

Table 13.

For levelised cost calculations, a 13-year unit life can be assumed.

6.3.3 Operating and Maintenance Costs (OpEx)

OpEx for such energy efficiency upgrades is typically assumed to be nil since the measure reduces electricity consumption for the same hot water service. The only OpEx term is therefore the incremental maintenance and servicing required to sustain expected performance and manage failure risk.

Professional servicing is commonly recommended on an annual basis, and may include flushing the tank to remove sediment, testing the temperature and pressure relief valve, and inspecting electrical connections (Rheem, 2025a). For models with connected controls, guidance also includes annual software/app updates to maintain functionality. Some programs note that warranties may be conditional on scheduled servicing by qualified personnel and may not include labour costs.

6.3.4 Associated System Costs

For upgrading an electrical water heater to a heat pump (an energy efficiency resource), associated network costs are assumed to be nil.

6.3.5 Resource Availability and Available Coincident Energy

The coincidence of load reduction with constrained energy periods depends on how the existing resistance units are controlled. If uncontrolled, average hot water load profiles typically shows a high morning peak and a slightly lower evening peak (Ausgrid, 2016), with overall load levels higher in winter than in summer. However, many of these systems are operated on controlled-load or off-peak setting, which schedule heating to overnight and/or daytime and may explicitly avoid evening morning or evening peak periods. In these cases, a large share of the conserved energy occurs in those controlled windows, so energy use reduction during peak constraint periods may be lower than implied by annual savings.

In line with space heating and cooling upgrades, a relationship between energy reduction of HPWH and resistance water heater can be established as:

$$\Delta E = E_{resistance} \left(1 - \frac{COP_{resistance}}{COP_{HWHP}} \right) \quad (33)$$

6.3.6 Facilitation Costs

Incentive Costs

Incentives for HPWH upgrades are delivered in the same way as space cooling and heating upgrades discussed above (through VEU, ESS, REPS and EEIS), mostly as an upfront discount facilitated through certificate-based state and territory (Larkin, 2025). In addition, eligible air-

source HPWHs can create STCs under the SRES, which are commonly assigned to the installer or provider and passed through to households as a point-of-sale discount.

For modelling, same as for space cooling and heating upgrades, the annual incentive costs (AUD/year) can be represented as:

$$C_{inc,HPWH} = N \times I \quad (34)$$

where N is the number of upgrades delivered under the program in the year and I is the average incentive per upgrade. To account for different certificate schemes, the incentive parameter can be estimated as:

$$I = \sum_k (n_{cert,k} \times p_{cert,k}) \quad (35)$$

Where n_{cert} is the number of certificates deemed per installation and p_{cert} is the average certificate prices for the relevant period and k indexes applicable certificate schemes.

Administration Costs

For HPWH upgrades, administrative tasks include eligibility checks, verifying the installed product meets scheme product requirements, verifying installer licensing requirements, meeting pre-installation requirements, managing decommissioning and disposal evidence, providing required consumer information, and retaining required records. The modelling formulation for HPWH upgrade administration cost would be similar to space cooling and heating upgrades.

Free Rider Costs

Same as the previous Section 6.2.6 (see also Section 6.1.6), free rider cost can be assumed at 13% of total incentive costs.

6.3.7 Resource Potential

Electric resistance water heaters offer high potential for flexible load control but have relatively low energy efficiency, whereas heat pump water heaters deliver much higher efficiency but typically provide less operational flexibility. A practical way to capture both system benefits is to deploy different technologies by context, prioritising efficiency in some settings and flexibility in others (Roche et al., 2023).

One of the factors affecting technical potential is that not all models are suitable for climates where winter ambient temperatures regularly fall below $\sim 5^{\circ}\text{C}$. Moreover, many systems include a resistance booster element to maintain output in colder periods or during high draw events. This can reduce realised seasonal efficiency if boosting is frequent.

HPWH compressors are generally located outdoors (or require ducted ventilation for indoor units), which limits applicability in some apartments and space-constrained dwellings.

Only air source heat pumps with a capacity of no more than 425 L are eligible to register for STC.

6.3.8 Data

Since same regional energy efficiency improvements schemes cover both space heating and cooling and heat pump water heater upgrades, many parameters related to the administrative

aspects of these technologies are shared. To avoid repetition, the Table 13 presents only the parameters specific to heat pump water heater upgrades, excluding those already reported in the Table 11 for space heating and cooling.

Table 13 Data sources for heat pump water heater upgrades.

Parameter	Unit	Type	Source
Uptake	Units by year	Meta	Roche et al. (2023)
Operating costs	\$/year	OPEX	Choice (2025a); Roche et al. (2023); Victoria State Government (2025b)
Capital costs	\$	CAPEX	
COP	-	Performance	Roche et al. (2023)
Number of installations per year	Unit/year	Meta	CSIRO (2026a)
Annual Energy Consumption	(MJ/Year)	Performance	
Type and capacity of water heaters	% and Litre	Performance	
Efficiency Certificates price	\$	Facilitation cost	Demand Manager (2026)
Discounts for hot water upgrades	\$	Facilitation cost	Victoria State Government (2026b)
Upgrade & Intention to purchase: Hot Water Systems	%	Meta	Energy Consumers Australia (ECA) (2023)
Products Ownership: Hot Water Systems	%	Meta	Energy Consumers Australia (ECA) (2023)
Cost and unit projection data	\$, unit	Meta	(ACIL Allen, 2026; DCCEEW, 2025b)

6.4 Retirement and replacement of inefficient appliances

6.4.1 Resource description

This resource covers offering consumers the option of the retirement of inefficient existing in-service electrical appliances and their replacement with higher efficiency models that deliver the same primary service (e.g., refrigeration, clothes washing, dishwashing, entertainment display) with lower electricity use. In the residential context, appliance loads are estimated at approximately 30% of home energy use, although this share can be higher in thermally efficient homes.

Standby consumption is also relevant for some product classes and can account for 3% of household energy use. Refrigeration is mostly a priority appliance class for small commercial retrofits. Across business types, refrigeration can be responsible for 25% to 85% of total company energy use and replacing a system that is older than 10 years with an efficient new system can reduce refrigeration energy use by up to 30% (Department of Climate Change Energy the Environment and Water (DCCEEW), 2026b). In food and grocery stores, refrigeration is reported as the largest energy consumer and is responsible for around half of total store energy consumption, with lighting and general power contributing around 25% (Department of Climate Change Energy the Environment and Water (DCCEEW), 2026a). For commercial refrigerated cabinets, Australian businesses owned around 845,000 units in 2015. Sales are projected to increase by over 40% by 2035, with associated energy use projected to rise to over 9,000 GWh per year (Energy Rating, 2026b). Appliance efficiency is defined under the Australian Energy Rating framework (Australian

Government, 2024). Regulated products must meet Minimum Energy Performance Standards and, for specified categories, must display an in-store Energy Rating Label showing a comparative star rating and tested energy consumption (kWh).

6.4.2 Capital Costs (CapEx)

Capital costs of appliance replacement may include:

- i. the purchase price of the appliance,
- ii. delivery and placement,
- iii. connection and commissioning (as applicable), and
- iv. removal and disposal or recycling of existing unit

Installed costs vary with appliance class, capacity, efficiency tier, and whether the replacement is like-for-like (i.e., re-using existing space and service connections) or requires modification works. Installation and removal costs are typically low for plug-in, like-for-like replacements, and are higher when trades or compliance work is required.

For small commercial sites, CapEx is often dominated by refrigeration rather than small plug-in loads. Decommissioning costs should explicitly account for regulated handling requirements where applicable (e.g., refrigeration equipment with refrigerant charge) and for appropriate e-waste recycling.

6.4.3 Operating and Maintenance Costs (OpEx)

Same as previous energy efficiency measures discussed before in this section, the main OpEx term is any incremental maintenance and servicing required to maintain expected performance. For residential appliances, ongoing costs are usually low and mostly include routine user maintenance (cleaning and minor upkeep). For modelling, these can be treated as zero. For small commercial sites, OpEx can be considerable where the replacement involves commercial refrigeration and cabinets. This can be modelled as:

$$C_{op,app} = c_{service} \times f_{service} + c_{consumables} \quad (36)$$

where $c_{service}$ is the cost per service visit (or contract), $f_{service}$ is the annual service frequency, and $c_{consumables}$ captures any paid replacement items that are required to maintain performance (e.g., seals, filters), if applicable.

6.4.4 Associated System Costs

In line with other energy efficiency technologies, associated network costs are assumed to be zero.

6.4.5 Resource Availability and Available Coincident Energy

Coincidence with constrained energy periods varies strongly by end-use load shape. For continuous loads (e.g., refrigeration), energy reductions are distributed among all hours, so

savings are available for all hours, including constrained periods. For user-driven loads (dishwashers, washing machines, dryers), coincidence depends on time-of-day behaviour. Results of a survey by Energy Consumers Australia (ECA) (2023) indicate that these appliances are commonly used during the daytime (9am to 3pm). TV, lighting and other appliances are expected to contribute mostly to the evening peak (5pm and 8pm) when people arrive home from work (Australian Government, 2025a).

For modelling, annual electricity savings from an efficiency-only appliance replacement can be expressed at the appliance class level as:

$$\Delta E = \sum_i N_i (E_{i,old} - E_{i,new}) \quad (37)$$

Where i indexes appliance classes, N_i is the number of units replaced, and E terms are annual energy use per unit. Available coincident energy is the portion of ΔE that coincides with constrained energy periods.

6.4.6 Facilitation Costs

Incentive Costs

The incentives schemes for appliance removal and replacement work the same as other efficiency upgrade schemes discussed before in this section. The VEU program provides a discount for eligible high-efficiency fridges and freezers, subject to minimum star ratings and a specific volume band, with products required to be listed on the national GEMS register and the Essential Services Commission product register. Under the same framework, business cold room upgrades receive discounts that scale by cold room size and the installed efficiency package. The program noted that cold room products cannot be free and must meet a minimum customer contribution. The VEU also supports other appliance classes relevant to this resource, including high-efficiency clothes dryers and televisions. The ESS previously supported several appliance classes through the Sale of New Appliances method (including washing machines, dryers, dishwashers, refrigerators, freezers, and televisions), but this method ended in 2025. REPS also supports efficient appliance purchases through retailer offers, with activities including the purchase of refrigerators, freezers and dryers, and the removal/disposal of unwanted refrigerators or freezers for both residential and commercial consumers (Essential Services Commission, 2026a).

Administration Costs

For appliance removal and replacement, administration tasks mostly consist of the management of compliance and evidence. This includes verifying participant and site eligibility, confirming the installed product meets scheme requirements (including product register and GEMS registration where applicable), confirming installer and technician licensing where regulated work is required, managing evidence of decommissioning and disposal (including refrigerant recovery where relevant), providing required consumer disclosures, retaining records, and supporting audits and inspections. The costs can be formulated in the same way as other efficiency upgrades discussed before.

Free Rider Costs

As for the previous sections, free rider costs can be assumed to be 13% of total incentive costs.

6.4.7 Resource Potential

Parameters affecting technical potential, or that influence the availability of appliance replacements include:

- Star rating scales are periodically updated. Some revisions make the scale more stringent, while others recalibrate ratings to maintain comparability under revised methods or climate data. Therefore, newer labels are not always directly comparable with older labels.
- Refrigeration load may increase during extreme weather; therefore, refrigeration-related load reductions can be slightly higher during hot constrained periods than implied by average-day energy use.
- Service level and sizing strongly affect realised savings. Efficiency gains can be offset by purchasing larger-capacity units or additional features. Consequently, the technical potential calculation depends on controlling for appliance capacity and expected usage when estimating baseline and post-upgrade energy.
- For commercial refrigeration, weather sensitivity depends on whether the premises are air conditioned or fridges are located near open doors. For unconditioned sites, the hottest day in a month can increase daily energy consumption by about 20%, while conditioned sites show smaller increases (Energy Efficient Strategies, 2020).

6.4.8 Data

Table 14 below provides a list of sources required for estimating different cost components of appliance removal and replacement.

Table 14 Data sources for retirement and replacement of inefficient refrigerator and cold room.

Parameter	Unit	Type	Source
indicative retail purchase price, installation and removal costs for residential refrigerators, dishwashers, dryers, washing machine and TV	\$	CapEx	Bunnings Warehouse (2026); Choice (2025b); MB9 (2025); QuoteYard (2026)
Star ratings and eligible appliances	rating	Performance	Greenhouse and Energy Minimum Standards (GEMS) Regulator (2026)
Refrigerated cabinets repair and replacement costs	\$	CapEx/OpEx	Hospitality Connect (2025)
Star rating vs CapEx and OpEx	-	CapEx/OpEx	Canstar (2025)
Cold room discounts	\$	Facilitation costs	Victoria State Government (2025a)
Refrigerator and freezer discounts	\$	Facilitation costs	Victoria State Government (2025d)
Running costs and device specification	mixed	Performance/OpEx x	Energy Rating (2026a)
Products Ownership: Appliances	%	Meta	Energy Consumers Australia (ECA) (2023)
Appliance eligibility criteria for incentives	-	Meta	Essential Services Commission (2026a)

7 Illustrative inputs and outputs

Key Points

It is proposed that the first version of the FlexCost Report should:

- Clearly spell out the specific data inputs and outputs of FlexCost.
- Make clear that the first version of the FlexCost Report is presented as an initial ‘minimum viable product’, rather than a mature, fully developed version comparable to GenCost which has evolved over an eight-year period.
- Identify areas for improvement in future iterations of the FlexCost report.

7.1 Demand Side Resource data inputs

This chapter summarises the key data input and outputs parameters that are expected to be included in the first FlexCost report. Please note that the illustrative values presented below are **purely for illustrative purposes** and do not necessarily reflect data based on research, referenced literature or reliable sources. The actual inputs and data in the first FlexCost Report may diverge from those presented below.

Table 15 Global input parameters

Parameter	Metric	Illustrative value*
Cost of Capital/ interest rate	% pa	7%
Depreciation rate	% pa	3%
Analysis Time Horizon	years	10
Analysis Region	State/NEM	NEM
Regional Peak Demand	MW	33,000
Number of customers	Number	10,000,000
Period of analysis	hours/year	50
Period of analysis - Days per year	days/year	20
Period of analysis - Hours per day	avg hours/ event	2.5
Share of Peak Demand in Period of Analysis (%)	%	9%
Share of Peak Demand in Period of Analysis (MW)	MW	3,000
Energy in Period of Analysis (MWh pa)	MWh pa	75,000

* Note: Illustrative values - do not necessarily reflect actual data.

Table 16 Demand-side Resource technical parameters

Parameter	Metric	Illustrative value
Technology	text	Home battery
Measure	text	Install new battery with VPP
Category	DF/EE	DF
Instrument type	text	Rebate
Technology life	years	10
Maximum units per customer (used in estimating technical potential)	number	1
Average unit capacity	kW	10
Average unit energy	kWh	20
Average capacity available in constrained energy period	kW	5
Constrained energy period coincidence factor (Share of energy in constrained period available for)	%	80%

* Note: Illustrative values - do not necessarily reflect actual data.

Table 17 Demand-side Resource cost parameters

Parameter	Metric	Illustrative value
Measure	text	Install new battery with VPP
Capital cost per unit	\$	\$15,000
Installation cost per unit	\$	\$1,000
Fixed operating cost	\$ pa	\$0
Variable operating cost (e.g. losses on charging costs)	\$/kWh	\$0.03
Initial incentive (e.g. rebate)	\$	\$4000
Annual incentive (e.g. program participation payment)	\$ pa	\$0
Variable incentive (e.g. dispatch incentive in constrained energy period)	\$/kWh	\$1
Associated system cost (e.g. VPP control systems)	\$	\$500
Administration cost (e.g. administering rebate program and VPP)	\$/kWh	\$500
Net free rider ratio	%	10%

Blue indicates technology costs; purple indicated facilitation costs

7.2 Demand Side Resource data outputs

It is expected that the input data above will be valuable to a range of users and stakeholders. In addition, as noted in Chapter 4, FlexCost will publish derived values for Levelised Cost of Demand-side Technology in the period of analysis (LCODT_{POA}) and Levelised Cost of Demand-side Facilitation in the period of analysis (LCODF_{POA}). These values will allow comparison between costs of various demand-side resource and also between demand-side resources and supply-side resources.

These values are broadly analogous to the Levelised cost of electricity (LCOE) values presented in the GenCost report, as shown in Figure 1 in Chapter 2. However, the FlexCost LCODT and LCODF figures are not directly comparable to LCOE figures, as the LCOE figures refer to analysis of energy generated *throughout the year*, while LCODT and LCODF refer to the cost of energy *available in set periods*, such as for example the 50 most constrained hours of the year.

The charts below provide illustrations of how these values LCODT and LCODF may be presented, in this case for the most constrained 50 hours of the year.

Note that there are deliberately no figures on the y axis in the charts below to emphasise that these graphs are based on illustrative data only. These graphs should not be interpreted as reliable data and no substantive conclusions should be drawn from these charts. The actual FlexCost Report will include specific LCODT and LCODF values based on the best available data.

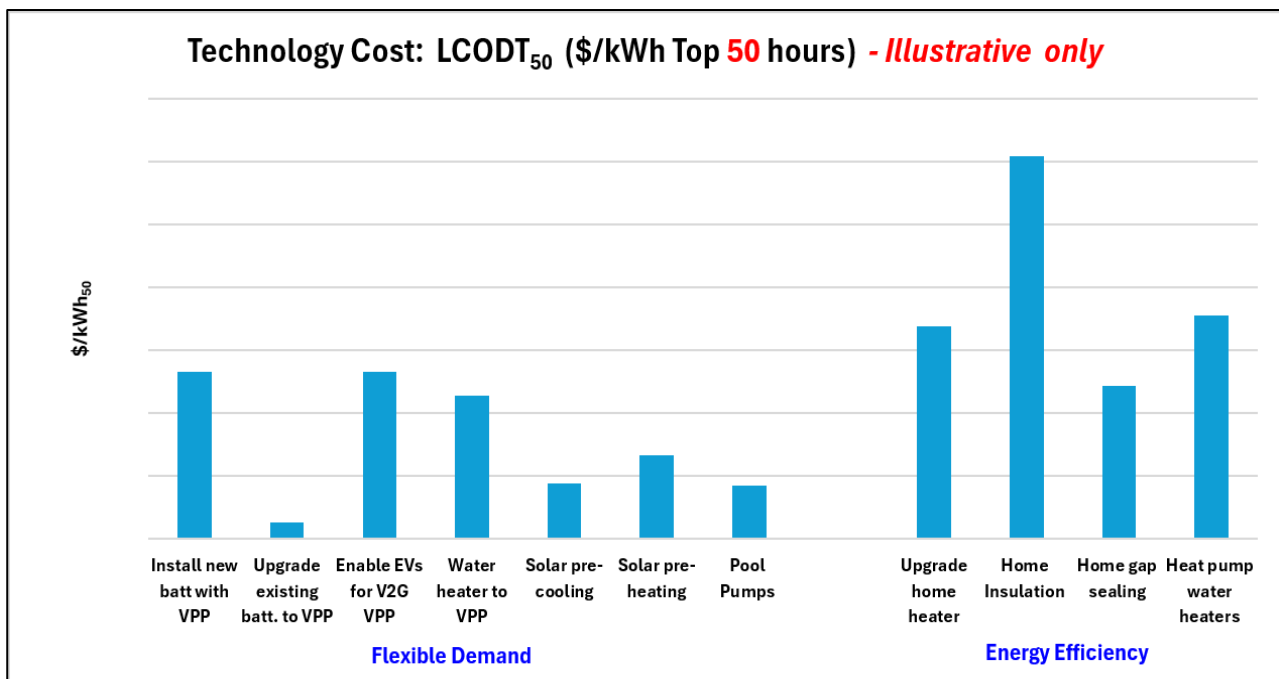


Figure 24 Levelised Costs of Demand-side Technology LCODT₅₀ (50 most constrained hours per year)

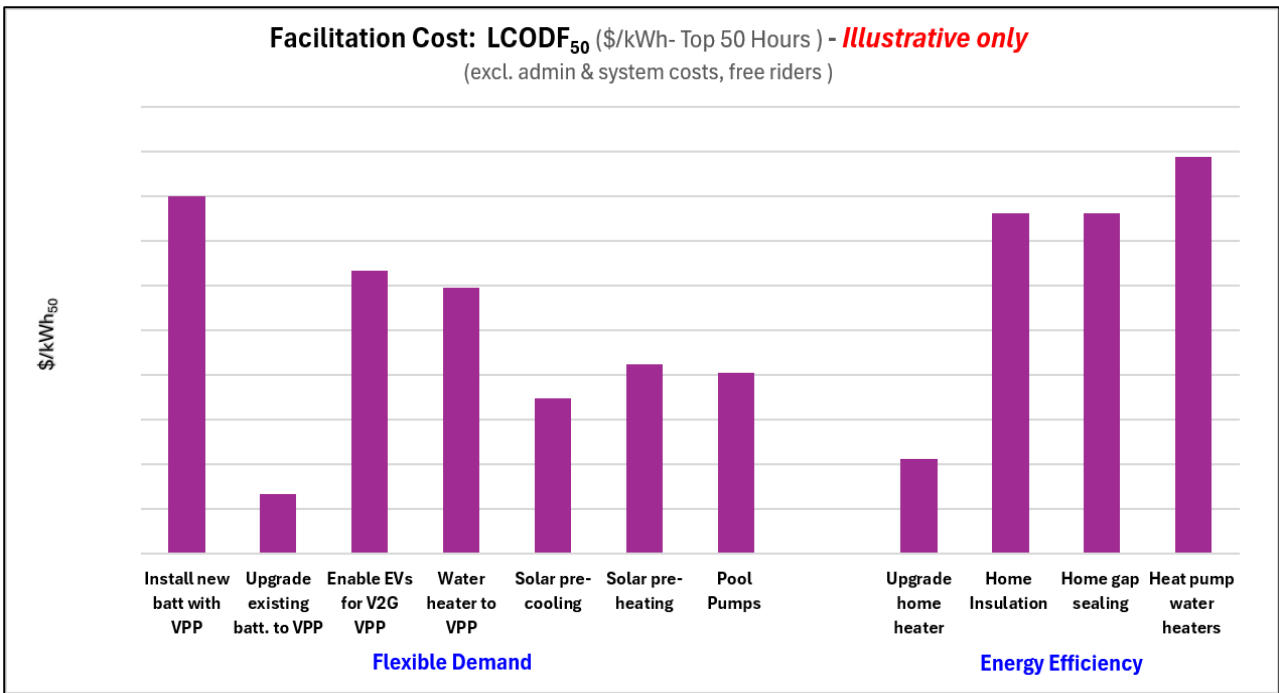


Figure 25 Levelised Costs of Demand-side Facilitation LCODF₅₀ (50 most constrained hours per year)

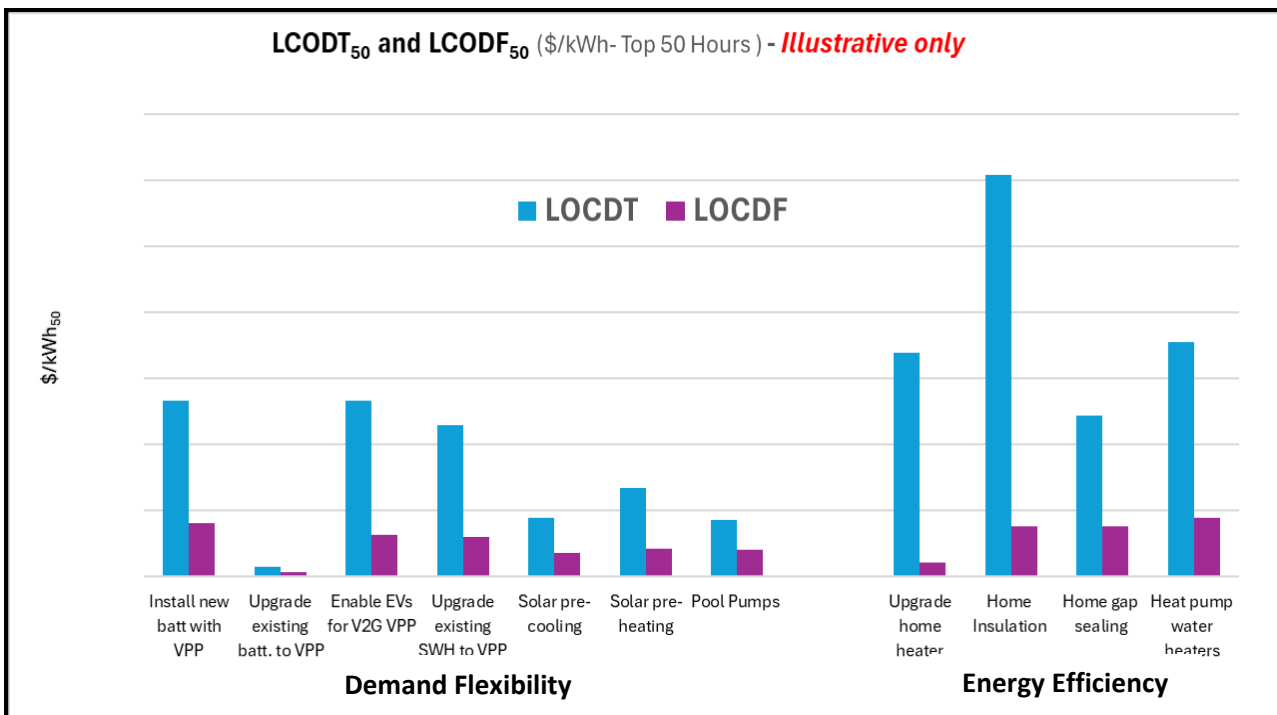


Figure 26 Levelised Costs of Demand-side Technology and Facilitation compared

Appendix A: Managing uncertainty in forecasting energy constraints

To paraphrase the philosopher Soren Kirkegaard, *“Life can only be understood backwards, but it must be lived forwards”*. This is also true for energy planning, which must be done in advance of expected demand, but must be based on past trends and experience. Accordingly, the analysis of when constrained energy periods occur discussed in Section 2.3 is based on observed, historical data about past supply and demand. Future demand and supply are not so predictable, but forecasts can be made based on generalised trends and tendencies as exhibited in the past. We cannot accurately predict what the temperature will be on Christmas Day next year, but we can confidently predict that next summer will be hotter than other times of the year.

To provide reliable forecasts of when constrained energy periods will occur, we must discern the underlying principles and trends from the random, or stochastic, variability caused by factors such as the weather, short-notice outages, or one-off events. Figure 27, Figure 28 and Figure 29 illustrate this process below.

Figure 27 shows the actual hourly demand for NSW throughout 2023. Figure 28 shows this same data but smoothed out by month and workday/non workday. In effect, all hours of the same clock-time (e.g., 17:00-18:00) on workdays within each month are assigned a common demand value equal to the average demand of those hours, and the same is done for non-workdays (weekends and public holidays). This produces a deterministic ‘baseline’ load shape that preserves recurring time-of-day and calendar effects while removing much of the hour-to-hour noise. The variability around the reference point can be treated as uncertainty. This is important because constrained energy periods are typically driven by a combination of predictable structure (e.g., evening peaks) and unpredictable deviations (for example, hotter than usual afternoons, sudden generator outages, or unusual industrial demand).

It can be seen from Figure 28, that Winter months show the highest baseline demand, with a strong evening peak and also a higher morning peak compared to summer. Shoulder periods have a flatter profile and lower overall demand. The working/non-working day effect is also clearer in Figure 28. Non-working days generally exhibit a lower baseline level and lower peaks, but the timing of the daily maximum is mainly unchanged.

It must be noted that the smoothing in Figure 28 is best interpreted as an illustrative realisation of the underlying demand process. Even when the general shape might be stable (e.g., morning and evening peaks, weekday/weekend separation, and summer and winter differences), the level and timing can shift from year to year (see abstract) due to weather conditions, economic activity, behavioural change, and gradual structural shifts such as increased rooftop PV and electrification. Figure 29 reduces year-specific noise by averaging the month, day-type and hour profiles for six years (2020-2025) and then mapping them onto a canonical 365-day calendar. An advantage of Figure 29 is that it clarifies which aspects of the smoothed profile are robust across years, and which are more likely to be driven by short lived conditions.

The patterns in Figure 28 and Figure 29 give an indicative guide to when constrained energy periods are more likely, because scarcity risk often occurs during recurring peak periods. However, demand alone does not reliably indicate constrained energy periods because constraints depend on demand relative to available supply after outages, network limits, and other operational

restrictions. Due to this reason, Figure 30 and Figure 31 extend the demand-based figures above by showing how wholesale prices in NSW vary by hour and season and therefore provide an indicator of periods when the system is relatively tight. Figure 30 shows the regional reference price for each hour of 2023. While there is substantial day-to-day variability, the most high-price events occur in late afternoon and early evening, consistent with periods when demand is typically high and demand flexibility is more needed. Negative prices are concentrated around the middle of the day in spring, indicating periods when supply can exceed demand (e.g., due to high solar output).

Figure 31 presents the same price data in a smoothed form, using the same approach as the smoothed demand profile. The figure indicates a recurring high price in the late afternoon and early evening, particularly during autumn and winter and more strongly on working days, which is consistent with the expected timing of constrained energy risk. Figure 32 applies the same smoothing logic to prices but averages across 2020-2025 (in a similar way to Figure 29). Comparing Figure 31 and Figure 32 shows that the magnitude and extent of some features are less pronounced in the averaged profile. In particular, the spring daytime negative-price region is visible in both figures, but it is more spatially concentrated and more moderated in Figure 32, consistent with year-to-year variability being reduced through averaging.

To move from historical patterns to decision-relevant forecasting, the analysis must explicitly recognise that constrained energy periods are inherently probabilistic. Figures above identify recurring demand and price structures, but they also show substantial residual variation around those structures. Therefore, what is required is an estimate of the likelihood that network energy constraints conditions occur within those windows, and the extent to which that likelihood changes across seasons, hours, and day types.

A pragmatic way to implement this is to set a threshold level for defining constraints based on wholesale prices, such as when the regional reference price exceeds \$300/MWh. This threshold level is arbitrary but plausible indicator of high-price conditions, noting that the appropriate threshold may vary by application and should be interpreted as a proxy for system tightness rather than a definitive measure of constrained energy periods. The probability of this event can be estimated empirically by counting exceedances within each month-hour-day-type category for several days. The NSW exceedance probability figure created based on period 2015-2025 (Figure 33) shows that the likelihood of prices above \$300/MWh is highly concentrated in a narrow set of conditions rather than being broadly distributed across the year.

The likelihood is highest in the late afternoon and early evening, especially in late autumn and winter. This is consistent with the demand results and shows that these hours have historically been when the network is most under pressure. Outside these times, the likelihood is much lower, particularly overnight and through most of the middle of the day, when prices rarely exceed \$300/MWh in most months.

These probability estimates can also be used to understand when flexible assets are most useful. They provide the most value when they are available during periods more likely to experience energy deficits due to network constraints. For example, if these conditions occur more often in certain evening hours, what matters most is not general availability across the year, but whether the asset can operate during those specific hours. This includes having enough duration, responding quickly, and being able to deliver energy despite any network limits at the time.

The probabilistic analysis also makes it possible to test whether the assumptions about when energy deficits occur due to network supply-demand imbalances are correct. This can be evaluated through 'hold-out back testing'. A baseline model is developed using historical data, while separate time periods (hold-out periods) are excluded from model development. These

hold-out periods are then used to test the model to provide an independent check of how good it performs on previously unseen data. Model performance can be assessed by checking how often actual high-price events occur during the periods identified as high risk. Forecasts can still be wrong, so this risk needs to be managed. Even a well-calibrated probabilistic model cannot remove forecast error because some causes of energy constraints are unpredictable, such as forced outages and extreme weather.

Risk management therefore requires strategies that remain effective even when forecasts are wrong. This includes maintaining conservative reserves during uncertain periods, ensuring flexibility that can respond in real time, and diversifying sources of flexibility. This approach follows standard electricity planning practice, using historical data, testing assumptions, and selecting strategies that maintain reliability under uncertainty.

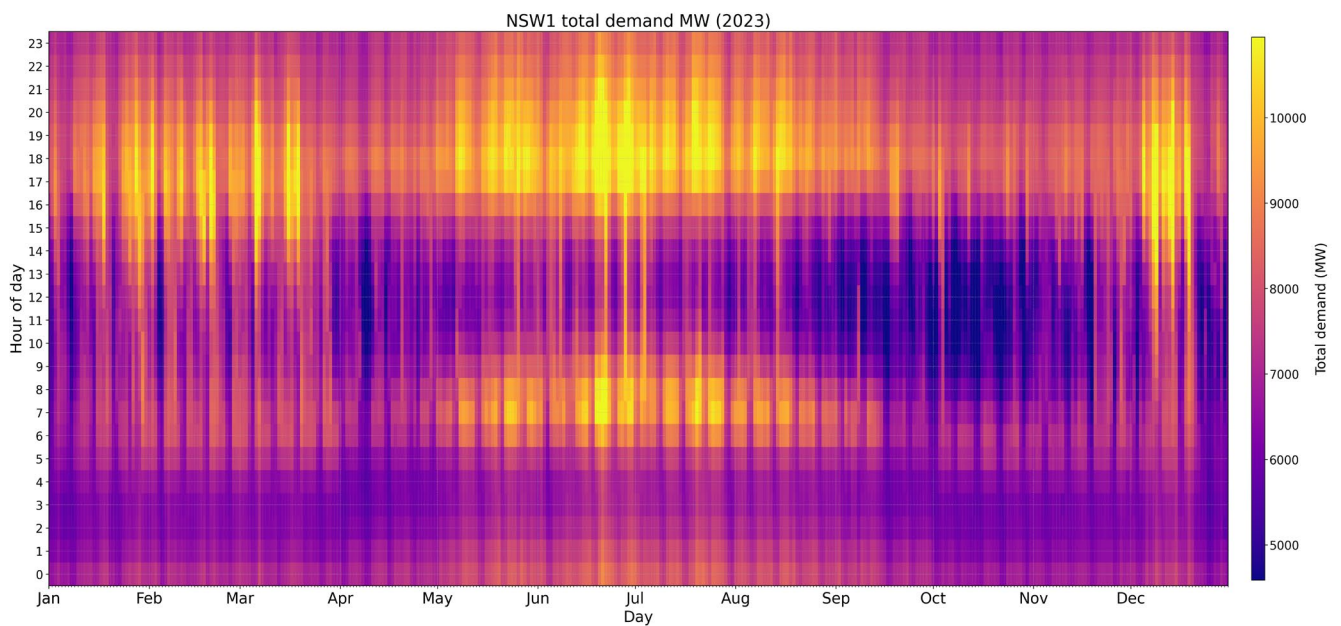


Figure 27 Demand in the NSW, 2023 (hours, MW)

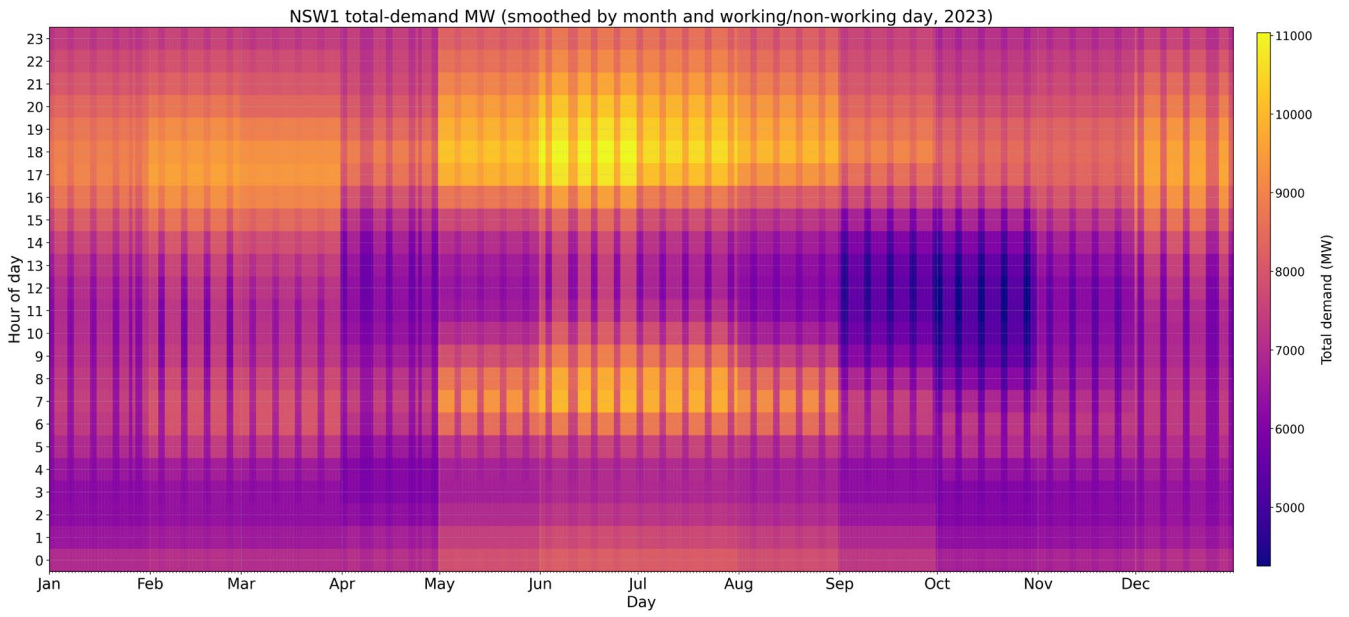


Figure 28 Demand in the NSW, 2023 - Smoothed by month and work/non-workday (hours, MW)

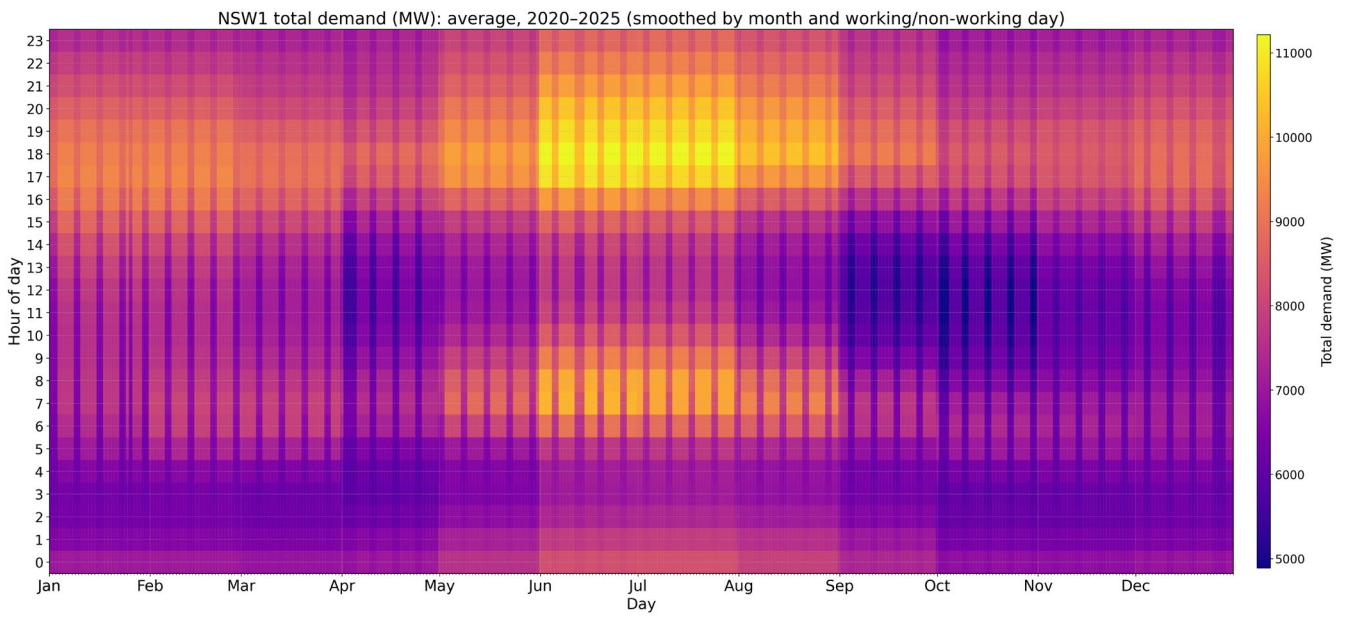


Figure 29 Demand in the NSW, 2020-25 average - Smoothed by month and work/non-workday (hours, MW)

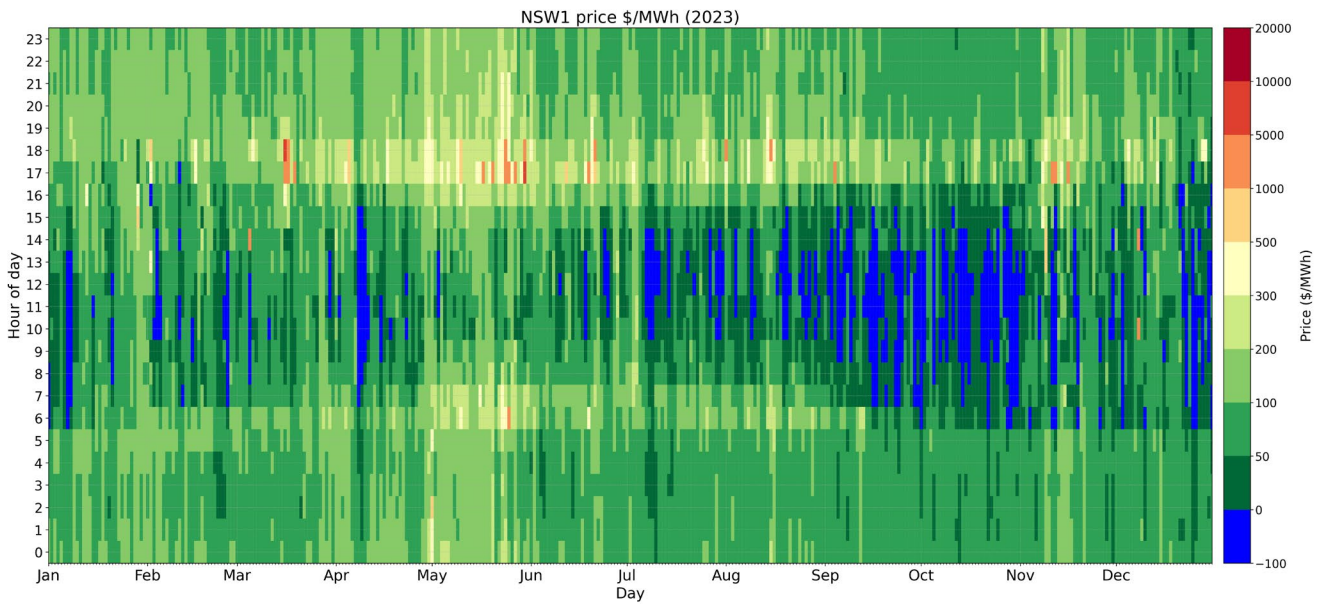


Figure 30 Regional wholesale price in the NSW, 2023 (hours, \$/MWh)

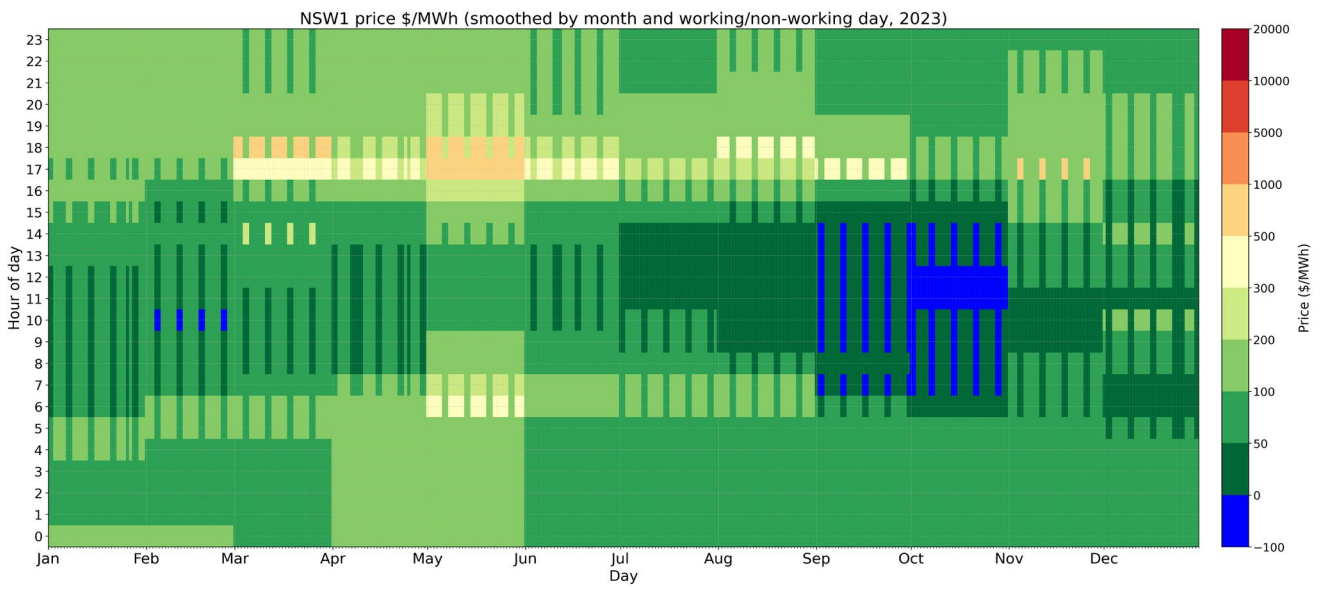


Figure 31 Regional wholesale price in the NSW - Smoothed by month and work/non-workday, 2023 (hours, \$/MWh)

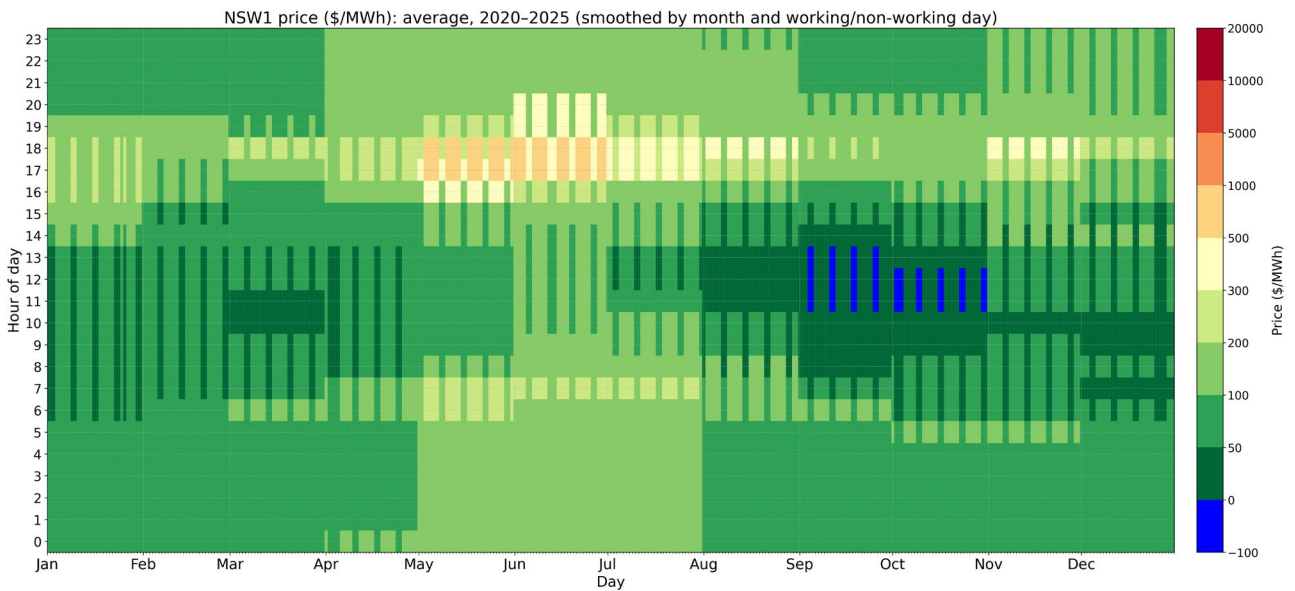


Figure 32 Regional wholesale price in the NSW, 2020-25 average - Smoothed by month and work/non-workday (hours, \$/MWh)

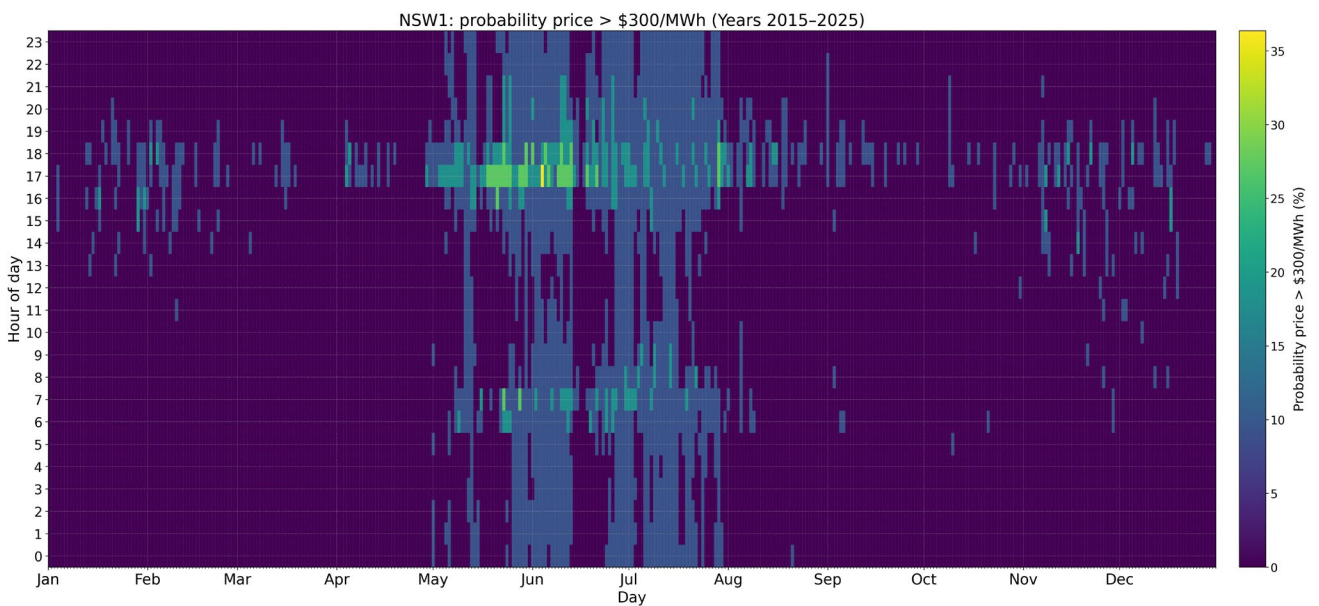


Figure 33 Probability of NSW regional price exceeding \$300/MWh (2015-25 data) (hours, %)

While these figures are not definitive, they do provide a good guide for when constrained energy deficits will occur.

It is recommended that further work is undertaken to apply robust statistical analysis to firm up the assumptions about when constrained energy deficits are most likely to occur.

Appendix B: Technology Parameters

This appendix summarises an initial list of the key data sources and parameter assumptions required for implementing the FlexCost methodology.

The table below (B.1) lists the main technical, economic, and program-related parameters for different end-use technologies. For each parameter, the table identifies the relevant unit, type (e.g., performance, CAPEX, OPEX, or program), and the corresponding data source. The dataset includes information from academic studies, industry reports, regulatory documents, and market datasets. Performance parameters include both design and operational parameters (Schmidt & Staffell, 2024).

This Appendix indicates that many of the required parameters can be sourced from existing Australian datasets, coverage is not uniform for all the technologies or parameter types. For more established options such as electric water heaters, residential air conditioning, PV and batteries, most performance and cost parameters are already reported in regulatory filings, market datasets and established industry studies, and are likely to remain available on an ongoing basis. Unlike those parameters, several program-related and behavioural parameters are less well supported by consistent data. Examples include long-term participation and attrition rates for newer DR products, EV availability and charging behaviour under orchestration, and battery wear costs for V2G.

For these parameters, current evidence often comes from a limited number of pilots and is subject to change as programs scale. In these cases, future versions of FlexCost may need to rely on indicative ranges, expert judgement and sensitivity analysis, as new empirical data become available. In general, the existing sources appear sufficient to implement an initial version of the framework for priority technologies, but some parameters will require further data collection or refinement for detailed program design and for emerging resources.

B.1 List of possible parameters for estimating cost of DF and EE and the source of the data.

Category	Parameter	Unit	Type	Source
Storage water heaters	Tank volume	L	Performance	Roche et al. (2023), BIS Oxford Economics (2018)
	Tank's SOC	%	Performance	RACE for 2030 (2025)
	Element rating	kW	Performance	Roche et al. (2023)
	Thermal capacity	kWh_th	Performance	RACE for 2030 (2025)
	Coefficient of performance	-	Performance	Roche et al. (2023)
	Average peak demand created by uncontrolled EHW	kW	Performance	Ausgrid (2016)
	Standby losses	kWh_th/day	Performance	Manufacturer data, GEMS database

DR enablement device cost	\$/device	CAPEX	Program docs, Associates (Associates, 2020), RACE for 2030 (2025)
Communications cost	\$/site-year	OPEX	Program docs, Associates (Associates, 2020), RACE for 2030 (2025)
Controlled-load windows	time window	Constraint	DNISP tariff guides, RACE for 2030 (2025)
Event parameters	events/season; h	Program	RACE for 2030 (2025)
Customer incentive	\$/event or \$/year	Program	Government (2025)
Maintenance costs	\$/year	OPEX	RACE for 2030 (2025)
Opt-out rate	%	Program	Ausgrid (2022a), Ausgrid (2016)
Projection data	Number of units/year	Meta	Roche et al. (2023)
Load profiles	%/hour of day	Performance	RACE for 2030 (2025), Ausgrid (2016)
Efficiency rating	Rate 1-10	Performance	CSIRO (2025a)
Peak demand by air conditioning	kW/hour of day	Performance	Ausgrid (2016)
DR modes shed fraction	fraction or kW/event	Performance	Associates (Associates, 2020)
Enablement hardware cost	\$/device	CAPEX	Associates (Associates, 2020), Embertec (2023)
Comms/platform cost	\$/site-year	OPEX	Embertec (2023)
Event parameters	events/season; h	Program	Embertec (2023), Ausgrid (2016)
Customer incentive	\$/event or \$/year	Program	Ausgrid (2016)
Penetration	%/year	Program	Ausgrid (2016)
Opt-out rate	%	Program	Ausgrid (2022a), Ausgrid (2016)
Load profiles	kW/hour of day	Performance	Ausgrid (2016)

Air conditioning

Battery	Peak demand reduction (kW) per active DR participants	kW	Program	Ausgrid (2022a)
	Efficiency rating	Rate 1-10	Performance	CSIRO (2025a)
	Battery capital cost	\$/kWh	CAPEX	CSIRO (2025c), AECOM (2019)
	O&M cost	\$/kWh per year	OPEX	AECOM (2019)
	BOS and installation	\$/kW or \$/kWh	CAPEX	CSIRO (2025c)
	Replacement cost	\$	CAPEX	CSIRO (2025c)
	Battery capacity	kWh	Performance	CSIRO (2024d), AECOM (2019)
	Degradation model params	varies	Performance	CSIRO (2024d)
	Rated output	kW	Performance	AECOM (2019)
	Round-trip efficiency (RTE)	fraction	Performance	CSIRO (2024d)
	Charging efficiency	fraction	Performance	CSIRO (2024d)
	Discharging efficiency	fraction	Performance	CSIRO (2024d)
	Dispatch time	hour	Performance	AECOM (2019)
	Max SOC	%	Constraint	CSIRO (2024d)
	Min SOC	%	Constraint	CSIRO (2024d)
Initial SOC	%	Meta	CSIRO (2024d)	
End-of-life SOH	%	Constraint	CSIRO (2024d)	
Cycle life	cycles	Performance	CSIRO (2024d), AECOM (2019)	
EV	Participation rate	% of eligible	Program	Council (2024b), CutlerMerz (2023), AGL (2023)
	EV battery energy capacity	kWh	Performance	Council (2024b), Thrän et al. (2025), Department for Transport and Driver and Vehicle Licensing Agency (2025)
	Opt-out rate	%	Program	AGL (2023), CutlerMerz (2023)
	Initial SOC	%	Performance	Energeia (2024)
	Charger's power capacity	kW	Performance	Thrän et al. (2025)
	Base plug-in time (avg)	h	Performance	Transport (2025), Thrän et al. (2025),

EV battery charging efficiency	%	Performance	Thrän et al. (2025), Zhang et al. (2016)
EV battery discharging efficiency	%	Performance	Thrän et al. (2025), Zhang et al. (2016)
Guaranteed minimum charge	%	Constraint	Thrän et al. (2025), Energy (2024)
Frequency of charge	%	Constraint	CutlerMerz (2023)
Charging rate	%	Constraint	CutlerMerz (2023)
Calendar life limit	years	Constraint	Manufacturer/EVC
Mileage life limit	km	Constraint	CutlerMerz (2023), Council (2024b)
Energy consumption rate	kWh/km	Performance	Origin (2023), CutlerMerz (2023), AGL (2023), CSIRO (2025b)
Average daily commuting distance	km/day	Meta	Council (2024a)
Road vehicle kilometres travelled	Vehicle kilometres per year	Meta	CSIRO (2025b)
Age threshold for battery replacement	years	Constraint	Assumption, Pickles (2024)
Battery cycle life	Cycles or SoH	Performance	Geotab (2024), Pickles (2024)
Battery cost	\$/kWh	CAPEX	CSIRO (2025c)
Charging profiles	kW per hour of day	Performance	Energeia (2024), CutlerMerz (2023), CSIRO (2025b)
Incentives	\$	Program	CutlerMerz (2023)
General EV costs	\$	CAPEX	Council (2024b), Council (2024a)
Cost to enable charging	\$	CAPEX	Council (2024a)
EV sales	count	Meta	CSIRO (2025b)
Summary of state government EV incentives	-	Meta	CSIRO (2025b)
Projection data	count	Meta	Council (2024b), CSIRO (2025b)
<i>EV Charger</i> Bidirectional charger power	kW	Performance	Energeia (2024), Council (2024b)
Number of chargers	count	Program	Energeia (2024)
Number of Intervals by Charger	count	Program	Energeia (2024)

<i>Heat pumps</i>	Bidirectional charger premium	\$/kW	CAPEX	enx (2023), Origin (2023)
	Home charger power capacity	kW	Performance	enx (2023)
	O&M cost	\$/year	OPEX	Electric Vehicle Council (2024a)
	Charger unit cost	\$	CAPEX	NSW Government (2024)
	Lifespan	years	Constraint	NSW Government (2025b)
	Installed cost	\$	CAPEX	RACE for 2030 (2025)
	COP	ratio	Performance	RACE for 2030 (2025)
	Storage volume / thermal mass	L; kWh_th	Performance	RACE for 2030 (2025)
	Controls cost	\$	CAPEX	RACE for 2030 (2025)
	Maintenance costs	\$/year	OPEX	RACE for 2030 (2025)
	Lifetime	years	Constraint	RACE for 2030 (2025)
<i>PV</i>	Enablement hardware cost	\$/device	CAPEX	RACE for 2030 (2025)
	Efficiency rating	Rate 1-10	Performance	CSIRO (2025a)
	Module cost	\$/W dc	CAPEX	IEA (2023)
	Inverter cost	\$/W ac	CAPEX	IEA (2023)
	BOS materials	\$/W	CAPEX	CSIRO (2025c), CSIRO (2025c); IEA (2023)
	Design and overheads	\$/W	CAPEX	CSIRO (2025c), CSIRO (2025c); IEA (2023)
	Installed labour	\$/W	CAPEX	CSIRO (2025c), IEA (2023)
	Permitting and connection	\$	CAPEX	IEA (2023)
	Fixed O&M	\$/kW-year	OPEX	CSIRO (2025c), CSIRO (2025c); IEA (2023)
	Variable O&M	\$/MWh	OPEX	CSIRO (2025c), CSIRO (2025c); IEA (2023)
Inverter replacement	\$	CAPEX	CSIRO (2025c)	
DC:AC ratio	ratio	Performance	CSIRO (2025c)	

<i>Energy Efficiency (space cooling/heating upgrades)</i>	Performance ratio	fraction	Performance	ARENA PR benchmarks
	Degradation	%/year	Performance	CSIRO (2025c)
	Yield per year	kWh/kW-year	Performance	APVI, Geoscience Australia
	Projection data	varies	Meta	CSIRO (2024d), CER postcode data
	Installed capacity	GW-year	Meta	AEMO (2025b), IEA (2023)
	Efficiency rating	Rate 1-10	Performance	CSIRO (2025a)
	Conservation Load Factor (CLF)	-	Meta	Department of Resources Energy and Tourism (2011); Oakley Greenwood (2012); Strategy. Policy. Research. (2019)
	COPs and EERs	-	Performance	Energy Rating (2025)
	Heating & Cooling Load in Different Cities	%	Performance	Belusko et al. (2019)
	Star rating vs annual consumption	kWh/year	Performance	Belusko et al. (2019)
	consumption of electrical end-uses in reference buildings	kWh/year	Performance	Belusko et al. (2019)
	Cost of cooling and heating devices and installation	\$	CAPEX	Choice (2023)
	Running costs	\$	OPEX	Government of South Australia (2025)
	Administration costs	\$	Facilitation Costs	Essential Services Commission (2026b); Victoria State Government (2025e)
	Number of scheme participants and certificates	unit	Meta	Department of Climate Change Energy the Environment and Water (DCCEEW) (2025)
Space conditioning average energy use per household per source per region	kWh/dwelling	Meta	Rajagopalan (2023)	

Energy Efficiency (insulation and thermal efficiency retrofit)

Insulation cost	\$ per dwelling	CapEx	Insulation Easy (2025); Rajagopalan (2023)
Cavity wall insulation costs	\$ per dwelling	CapEx	
Combined package cost	\$ per dwelling	CapEx	
Scheme administration costs	\$	Facilitation cost	COAG Energy Council (2019); ICANZ (2024)
Inspection/ assessment cost	\$	Facilitation cost	
Dwelling renovation rate	%	Meta	
Uptake rate	%	Meta	
Typical property specifications	-	Meta	
Rental proportion of housing stock (rate)	%	Meta	
Average dwelling Star rating per state	score	Meta	Rajagopalan (2023)
Proportion of Dwellings with Insulation	%	Meta	ICANZ (2024)
Locations of Insulation for houses reporting insulation	% in each region	Meta	
Useful life of measures	year	Meta	Deloitte (2024)
Energy rating vs heating and cooling load (different spatial resolutions)	mixed	Meta	CSIRO (2026b)
Weather sealing discounts	\$	Facilitation cost	Victoria State Government (2026c)
Window glazing discounts	\$	Facilitation cost	Victoria State Government (2026d)
<i>Energy Efficiency (HPWH upgrades)</i> Uptake	Units by year	Meta	Roche et al. (2023)
Operating costs	\$/year	OPEX	Choice (2025a); Roche et al.
Capital costs	\$	CAPEX	

			(2023); Victoria State Government (2025b)	
	COP	-	Performance	Roche et al. (2023)
<i>Energy Efficiency (appliance removal and replacement)</i>	Number of installations per year	Unit/year	Meta	CSIRO (2026a)
	Annual Energy Consumption	(MJ/Year)	Performance	
	Type and capacity of water heaters	% and Litre	Performance	
	indicative retail purchase price, installation and removal costs for residential refrigerators, dishwashers, dryers, washing machine and TV	\$	CapEx	Bunnings Warehouse (2026); Choice (2025b); MB9 (2025); QuoteYard (2026)
	Star ratings and eligible appliances	rating	Performance	Greenhouse and Energy Minimum Standards (GEMS) Regulator (2026)
	Refrigerated cabinets repair and replacement costs	\$	CapEx/OpEx	Hospitality Connect (2025)
	Star rating vs CapEx and OpEx	-	CapEx/OpEx	Canstar (2025)
	Cold room discounts	\$	Facilitation costs	Victoria State Government (2025a)
	Refrigerator and freezer discounts	\$	Facilitation costs	Victoria State Government (2025d)
	Running costs and device specification	mixed	Performance /OpEx	Energy Rating (2026a)
<i>General</i>	COPs and EERs	-	Performance	Energy Rating (2025)
	Heating & Cooling Load in Different Cities	%	Performance	Belusko et al. (2019)
	Star rating vs annual consumption	kWh/year	Performance	Belusko et al. (2019)
	consumption of electrical end-uses in reference buildings	kWh/year	Performance	Belusko et al. (2019)
	Cost of cooling and heating devices and installation	\$	CAPEX	Choice (2023)
	Running costs	\$	OPEX	Government of South Australia (2025)

Administration costs	\$	Facilitation Costs	Essential Services Commission (2026b); Victoria State Government (2025e)
Number of scheme participants and certificates	unit	Meta	Department of Climate Change Energy the Environment and Water (DCCEEW) (2025)
Space conditioning average energy use per household per source per region	kWh/dwelling	Meta	Rajagopalan (2023)
Wholesale spot price	\$/MWh	Market	AEMO (2025e)
Projection of price	\$/MWh	Market	AEMC (2024b)
CER projections	counts; kW; kWh	Meta	CSIRO (2020, 2024d), CER
Consumption and demand projections	MWh; MW	Market	AEMO (2024), AEMO (2025b)
DSP scenarios projections	varies	Market	AEMO (2024), AEMO (2025b)
New transmission projection	km; \$	Market	AEMO (2024), AEMO (2025b)
Storage capacity projections	MW; MWh	Market	AEMO (2024)
Gas peaker offtake projections	GJ; MWh	Market	AEMO (2024)
Average grid emissions factors	kg CO ₂ e/kWh	Market	CSIRO (2025d)
Marginal emissions factors	kg CO ₂ e/kWh	Market	Heim (2023)
Emissions projection	kg CO ₂ e/kWh per year	Market	Electricity (2025)
Orchestration assumptions		Market	ARENA (2024)

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