Clean Energy Council submission to the Australian Energy Regulator Issues Paper: Connection Guideline review: Static zero limits for micro embedded generators

The Clean Energy Council (CEC) welcomes the opportunity to provide feedback on the Australian Energy Regulator (AER) Issues Paper on static zero limits for micro embedded generators.

The CEC is the peak body for the clean energy industry in Australia. We represent and work with Australia's leading renewable energy and energy storage businesses, as well as accredited designers and installers of solar and battery systems, to further the development of clean energy in Australia. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

The CEC supports the stated position of the AER, based on its initial consultation, that "the imposition of a static zero limit should be a rare event that happens in exceptional circumstances only".

We note that Ministers have agreed to include emissions reduction in the National Energy Objectives (NEO). This should be acknowledged as a material consideration. It could, for example, affect methodologies for cost-benefit analysis if we are to properly account for the emission reduction benefits of zero emissions generation displacing fossil fuels.

We support the AER proposal that customers subject to a static zero export limitation should have access to information including:

- A clear explanation of the methodology, data and calculations used to determine that the best technical, economic and social outcome was for a static zero export limit to apply in a specific part of the network,
- Access to independent technical expertise to review the distributor's analysis, and
- How to access dispute resolution processes.

In addition, the CEC would also recommend customers be provided with:

- A description of what action the distribution network service provider (DNSP) has taken to address the problem,
- A description of any additional steps that could be taken, but haven't and an explanation why not,
- Customer access to data (including local, real time voltage data from their own meters) to enable verification or challenge of some of the DNSPs assertions, and
- Information as to whether the DNSP was approved for augmentation expenditure for the relevant feeder and, if so, why the expenditure will not be used for that purpose.

Network visibility will be a crucial component in the development of a framework to demonstrate why DNSPs decide to impose static zero export limits in some parts of their network and not others. The Australian Energy Market Commission (AEMC) review of metering services is an important opportunity to enable network visibility by providing DNSPs with access to power quality data from smart meters.

The success of this AER initiative relies on success by the AEMC in its efforts to improve network visibility through its review of metering services.

The AER should establish a process for review and appeals regarding DNSP decisions to impose a static zero export limit.

Dynamic operating envelopes (DOEs) are the long-term solution to addressing the issue of how to allow new exports when the line is unable to accommodate more uncontrolled exports. Customers on a static export connection agreement should be allowed to ‘opt in’ to a dynamic connection agreement.

We would be happy to discuss these issues in further detail with representatives of the AER. We look forward to contributing further to the development and implementation of this important area for energy policy.

Responses to Questions Raised in the Consultation Paper

In the remainder of this submission, we respond to the questions raised in the consultation paper.

1. **Under what limited circumstances should distributors be able to impose static zero export limits?**

The issues noted in the Issues Paper are voltage management and reverse power flow.

The work by the Victorian Government indicates that rooftop solar exports make only a small contribution to voltage issues

Distribution Network Service Providers (DNSPs) that cite voltage management or reverse power flow as the reason for zero export limits they should be required to demonstrate what other steps have been taken and whether the other options have been exhausted. Energy Consumers Australia (ECA) has commissioned Renew to study the costs of various voltage management options (see attachment 1) and studies such as this should underpin assessment of options. In the example outlined in 'Case study 1' for example, the customer who is refused approval to export should also be given an explanation as to what steps have been taken to adjust voltage, and why there are no other steps that can be take except to limit exports to zero. Social license will be strengthened if customers have access to information to demonstrate that the DNSP has taken all prudent steps to adjust voltage levels and is not just blaming solar for network management issues.

Voltage management issues can be addressed by a range of measures (see Attachment 1). Reverse power flow can be addressed with community batteries and/or tariffs to encourage electricity consumption during daylight hours, when solar energy is abundant. DOEs are also part of the longer-term solution.

The AER should establish a process for review and appeals regarding DNSP decisions to impose a static zero export limit.

We note that Ministers have agreed to include Australia's emissions reduction goals in the National Energy Objectives. This should be acknowledged as a material consideration for the purposes of this Issues Paper.

2. **Under what circumstances should we take into account equity issues when considering the application of static zero limits?**

As noted in the Issues Paper, "pre-existing rooftop solar systems are covered by the original connection contracts between customers and their distributors". There is a legacy of contracts entered into over the years, and these cannot be unilaterally amended.

DOEs are the long-term solution to addressing the issue of how to allow new exports when the line is unable to accommodate more uncontrolled exports. Customers on a static export connection agreement should be allowed to 'opt in' to a dynamic connection agreement.

3a. What are your views on networks using a 'standard approach' to decide on whether to impose a zero-export constraint for each individual application?

The Issues Paper suggests an approach by DNSPs that involves collection of data including voltage, load and solar output profiles. The data should also include what the DNSP has done in terms of voltage management. It will be important to be able to show customers that DNSPs are not simply assuming that all voltage management issues are caused by solar exports and that they have taken reasonable and prudent steps (such as transformer tap changes) prior to limiting exports.

The Issues Paper acknowledges that only the DNSPs in Victoria have full operational coverage, which is attributed to 100% smart meter coverage. The key barrier is lack of access to the data available from smart meters, not 100% coverage. DNSPs do not require 100% smart meter rollout on their low voltage (LV) networks for visibility. A proportion lower than 100% could suffice. However, the DNSPs need access to the power quality data from the smart meters installed in their network. The Australian Energy Market Commission (AEMC) is reviewing the regulatory framework for metering services and CEC has called on the AEMC to ensure that DNSPs will have access to the data. The AER policy should not proceed on the assumption that the AEMC will be unable to address the issue of DNSP access to data from smart meters.

The CEC has also called on the AEMC to amend the framework for metering services to enable customers (and their authorised agents) to access local, real time voltage data from their own meters. Among other benefits, this would provide customers with the information they need to be able to verify or challenge assertions by DNSPs regarding voltage management issues.

If a 'standard approach' is adopted, it should be:

- Based on DNSPs having visibility of their own network (assuming the AEMC amends the framework for metering services to allow this)
- Able to be verified by customers (and their authorised agents) using local, real time voltage data from their own meters.
- Transparent, with analysis published for each feeder
- Subject to independent review and an appeal process.

3b. If you consider a 'standard approach' to be inappropriate, what depth of analysis or study should networks be required to do in the limited circumstance where a static zero export limit may need to be imposed? What would be the likely costs of this level of study? Should the costs of the study be charged on a requester or treated as a general network administration cost?

The ability of DNSPs to efficiently analyse the hosting capacity of their LV networks will be determined, to a significant degree, by the visibility of the LV network and the data available to the DNSP. The CEC is calling on the AEMC to ensure that power quality data from smart meters is available to DNSPs to assist with efficient network management. If this happens, the cost of analysis should be significantly reduced. It is difficult to answer this question without knowing whether networks will in future have access to power quality data from smart meters. It would make sense for the AER to await the Final Determination of the AEMC review of metering services, rather than assuming that power quality data will not be made available to DNSPs.

4a. What information should the distributor provide the connection applicant when a distributor proposes a static zero export limit and how should that information be provided?

We support the AER proposal that customers subject to a static zero export limitation should have access to information including:

- A clear explanation of the methodology, data and calculations used to determine that the best technical, economic and social outcome was for a static zero export limit to apply in a specific part of the network,
- Access to independent technical expertise to review the distributor's analysis, and
- How to access dispute resolution processes.

In addition, the CEC recommends customers be provided with:

- A description of what action the DNSP has taken to address the problem,
- A description of any additional steps that could be taken, but haven't and an explanation why not,
- Customer access to data (including local, real time voltage data from their own meters) to enable verification or challenge of some of the DNSPs assertions, and
- Information as to whether the DNSP was approved for augmentation expenditure for the relevant feeder and, if so, why the expenditure will not be used for that purpose.

4b. What's the best way to communicate the steps to inform customers' investment decisions? For example:

- **What type of information should customers be provided with, when should it be provided and by whom?**
- **Who is best placed to provide effective customer education before a customer makes an investment decision?**

The retailer and designer of a customer's DER system will be best placed to advise the customer on the implications of a static zero export limit on the appropriate design of the system, and the implications for the likely financial costs and benefits of the proposed investment.

The retailer (or their designer) would require access to information about which feeders have a static zero export limit.

5. Are there exceptional circumstances where it would be appropriate for a distributor to impose a static zero limit where it has already been funded under revenue determinations to augment the network?

It is difficult to understand why this would be justified unless it's a matter of timing. If so, there would need to be a process for relaxing the zero-export limit after the network is augmented.

6a. What conditions must be met in the limited circumstance that a static zero export limit is applied? Do you consider the above controls adequate?

We support the proposed approach. We note that there would be a need to review cost-benefit methodologies to take account of the emission reduction benefits of DER exports, in line with the recent inclusion of emission reduction goals in the NEO.

6b. In the limited circumstance that they are imposed, should static zero limits be subject to regular review? If so, what length should the period be?

Yes, they should be regularly reviewed.

The review period should not exceed the duration of a regulatory determination. It would make sense to do it towards the end of the determination period, so that DNSPs have had enough time for any augmentation that was approved in the regulatory determination.

7. At locations where it is not prudent nor efficient to augment the local network to increase the rooftop solar hosting capacity, should customers bear the cost for network augmentation if they wish to avoid export limitation?

The AER paper cites costs for transformer and substation upgrades. There are other steps that can be taken that are cheaper. Include these (maybe attach the Renew study as an appendix).

Demand on the network will grow as consumers adopt electric vehicles. Augmentation required for increased exports will be like augmentation for increased imports. The AER will need to make sure solar customers are not paying for upgrades that will be needed for EVs anyway.

Need information to be available regarding augmentation plans for increased load or other augmentation (e.g. putting overhead lines underground) and the anticipated timing and impact of the planned investments. For some customers, if their feeder is about to be upgraded for EVs and if that will allow them to avoid a static zero export limit, it might make sense to delay their DER investment until after the network has been augmented.

We also need DNSPs to support tariff reform to encourage EV charging and use of other electric appliances during daylight hours.

8. **Do you consider that the above charging practice is reasonable? If not, what do you consider is a reasonable charging practice?**

In the context of increasing demand (driven by EV charging) there will be some business as usual (BAU) augmentation built into future regulatory determinations. The BAU augmentation should be used as the baseline, rather than a ‘no growth’ assumption. This should include the post-2025 regulatory determination period when EV uptake is expected to increase.

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Renew DER Optimisation (Stage II): Final Report

Prepared for RENEW

September 2021

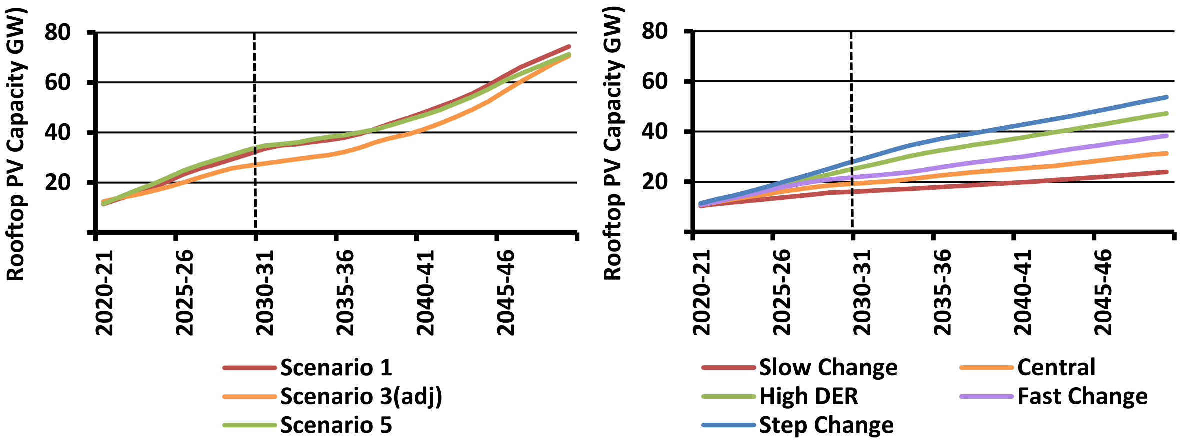
ENERGEIA

Executive Summary

Australia's Network Transformation Roadmap (NTR) found that up to 45%[1] of all electricity system investment over the period to 2050 would be made behind the meter by consumers or their agents. While this is starting to occur at the generation level, with an estimated 15%[2] of all generation capacity being attributed to behind-the-meter consumer generation, it is not yet the case at the network level, where the AEMC found non-network alternatives were being chosen for 0.15% of total investment, and Energeia's own research has found that less than 10%[3] of RIT-D projects in the last 3 years have implemented a non-network alternative.

While consumer investment in rooftop solar PV has been tracking the NTR view of a substantially more decentralised future, trends suggest solar PV could be increasingly[4] curtailed and/or blocked in the future. The Australian Energy Market Operator (AEMO) has called[5] for rooftop solar PV to be limited in the name of energy system security and reliability. In comparison to the NTR, AEMO's modelling of a high DER, low carbon future electricity system under its 'Step Change' scenario for the Integrated System Plan (ISP) sees consumer side investment in rooftop solar PV providing 18 GW[6] less capacity by 2050.

CSIRO/ENA's (Left) vs. AEMO's (Right) Rooftop Solar PV Capacity Forecasts in the National Electricity Market



Source: ENA NTR (2016), AEMO Inputs and Assumptions to 2020 ESOO (2020

The electricity industry, including key governing, regulatory and market bodies, has been focused on addressing the key barriers to optimal DER investment across a range of initiatives[7]. However, recently completed stakeholder engagement completed for this project has found that these industry initiatives are dominated by

[1] Energy Networks Australia (2017), 'National Transformation Roadmap', https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/, pg. i

[2] AER (2020), 'State of the Energy Market', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Chapter%201%20A3%20spread.pdf

[3] Energeia research of pre-2019 DAPRs and RIT-Ds across the National Electricity Market

[4] As alluded to in SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal': https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip, pg. 6, and supported by modelling results from L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[5] AEMO has called for DNSPs to provide real time visibility requirements for distributed solar PV to better enable curtailment , see AEMO (2020), 'Renewable Integration Study: Stage 1 Report', https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf

[6] AEMO (2020), '2020 Integrated System Plan', https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

[7] As highlighted in Section 1.3 of Energeia (2019), 'Distributed Energy Resources Enablement Project – Discussion and Options Paper', https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

centralised electricity system incumbents, both players as well as policymakers, regulators and market operators, in terms of participation and therefore perspective, and that they do not have a clear vision of what an optimal future least cost system looks like for consumers, beyond that of the perspectives of the NTR and the ISP.

Renew is a community-based member organisation that advocates for consumer interests in energy market policy.[8] It is therefore interested in developing the evidence base to identify the role of DER in the optimal future scenario for consumers, the key actions that will need to be taken to achieve it and their sequencing and timing, the roles of each industry group in their implementation, and perhaps most importantly, the net benefits of doing so and how they will be distributed across industry stakeholders, especially vulnerable consumers and those without DER.

Renew, supported financially by Energy Consumers Australia (ECA), undertook a project in 2019[9] to identify the key barriers to the efficient investment in DER and the least cost solutions for addressing them. A key finding[10] of that project was that a whole-of-system approach was needed to determine the optimal level of DER investment, and the optimal solutions for enabling it. Stage II of the project, which includes this report, seeks to address the analytical gaps identified in Stage I, as well as those identified via stakeholder consultation.

Scope and Approach

Energeia was engaged by Renew to develop and implement a whole-of-system modelling methodology that would support the achievement of Renew's DER enablement project Stage II objectives, namely, identifying the optimal future state for consumers that best meets the National Electricity Objectives (NEO), the role of DER, and the policy, regulatory, market and industry enablement needed to realise it. Importantly, the ECA Board required Energeia's modelling methodology and results to be reviewed by an independent expert selected by Renew.

Energeia's approach to developing and implementing a whole-of-system modelling methodology to identify the optimal consumer-focused future electricity system scenario involved:

- **Developing consumer focused scenarios of the future** – Energeia developed a consumer focused high DER and low carbon scenario of the future to compare with the ISP Step Change scenario.
- **Modelling the optimised future state for all customers** – Energeia ran our customer optimisation and generation models to identify the least cost mix of DER, network and generation over time.
- **Identifying the key barriers and drivers to the optimal future state** – Based on our learnings from the modelling, Energeia identified key barriers to the optimal future state and potential solutions
- **Developing the case for changing to the optimal future state** – The modelling outputs were brought together in a whole-of-system model to compare each scenarios overall costs
- **Engaging, consulting and validating with stakeholders and subject matter experts (SMEs)** – Energeia engaged with key stakeholders and SMEs throughout the process accordingly.

Energeia notes that this final report incorporates the feedback received from stakeholders and subject matter experts on our draft report.

[8] See Renew's mission statement, available at: https://renew.org.au/what-we-do/advocacy/consumer-focused-energy-markets/

[9] Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

[10] See Section 5.2 of Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

Consumer-Focused Scenarios of the Future

Energeia originally planned to develop up to four future scenarios using technology assumptions from AEMO's ISP and industry reported cost assumptions, e.g. Long-Run-Marginal-Cost (LRMC), however, Energeia's analysis of these assumptions found[11] that alternative assumptions would be more consistent with a consumer benefits-maximising scenario.

Energeia instead developed an alternative consumer focused scenario with different assumptions to those used in AEMO's highest [12] DER and electrification future state, it's Step Change scenario. The table below compares key assumptions across the AEMO and Consumer scenarios. The main differences are in forecast prices for distributed solar PV and battery storage technology, virtual-power-plant enrolment levels and DNSP LRMCs.

Comparison of Key Assumptions by Scenario

	Scenario Name	
	AEMO Step Change	Consumer High DER
Key Scenario Drivers		
Distributed Technology Prices		
Solar PV	AEMO Step Change	Trend
Storage	AEMO Step Change	Trend
Distributed Technology Adoption Rates		
Solar PV	39% by 2030, 49% by 2040	90% by 2030, 93% by 2040
Storage	14% by 2030, 24% by 2040	80% by 2030, 90% by 2040
Distributed Technology Adoption Sizes		
Solar PV	AEMO Step Change	Economically Optimal
Storage	AEMO Step Change	Economically Optimal
Electrification Rates		
Buildings	80% by 2030, 90% by 2040	80% by 2030, 90% by 2040
Transportation	AEMO Step Change	AEMO Step Change
DER Management		
Water Heating	100%	100%
Vehicle Charging	100%	100%
Storage	100%	100%
Solar PV	100%	100%
National Electricity Market		
Fuel Prices	AEMO Step Change	AEMO Step Change
Technology Costs	AEMO Step Change	AEMO Step Change
Networks		
LRMC	Published	Estimated

Source: Energeia

Additional scenarios and sensitivities are planned to be investigated in subsequent stages of this work program.

Optimal Future State for Consumers

Energeia modelled the optimal DER configuration for key customer classes over time given scenario assumptions to develop customer weighted estimates of DER adoption and sizing, coincident maximum demand, grid consumption and hourly load profiles to 2055 by scenario. These were then fed into our Virtual Power Plant (VPP) optimisation and wholesale market models to estimate the impacts on generation costs.

[11] This is discussed further in Section 3 and Energeia's analysis of the key ISP inputs and assumptions is reported in Section 4.1.2

[12] The Step Change scenario has approximately the same level of DER, but also assumes accelerated carbon emissions reductions.

The key findings from our whole-of-system modelling include:

- Optimised levels of DER adoption are lower than current rates of adoption, but rise over-time, with rooftop solar PV and Behind-the-Meter (BTM) storage capacity surpassing NTR levels due to lower forecast technology prices
- Optimised DER adoption at the pace assumed reduces long-run generation and network capacity requirements by 20%, and wholesale supplied energy by 40%, versus the ISP Step Change scenario
- The modelling shows rooftop PV is likely to be curtailed the most until 2030 when utility scale solar PV no longer receives Renewable Energy Credits (RECs), which allow it to bid negative prices into the market
- Managed DER, e.g. via VPPs using orchestration technology, plays a major role in shifting flexible load including water heating and vehicle charging to the middle of the day and optimizing curtailment
- Significant curtailment of solar PV and wind occurs under both scenarios, which is partially offset by VPP movement of water heating and EV charging into the middle of the day
- More utility scale lithium storage is invested in under the ISP Step Change scenario to meet the scenario's higher peak demand trajectory
- Volume weighted average prices under the Consumer High DER scenario are lower on average than the ISP High Change scenario, particularly for NSW, Victoria and South Australia post 2028

Key Barriers and Drivers of the Optimal Future State

Achieving the optimised DER configurations envisioned in the Consumer High DER scenario will require the deployment and integration of over 127 GW of rooftop solar PV and 136 GWh of behind the meter storage, as well as active management of electric vehicle charging and electric water heating.

Based on our experience modelling the optimal future electricity system state in the NTR, Energeia identified the key barriers and drivers that policymakers, regulators, market and institutional agencies and industry players will need to address to realize the identified optimal future state for consumers, which we have grouped into the following three themes:

- **Levelling the playing field** – The National Electricity Rules (NER), electricity system and its institutions are all geared to the centralised paradigm, which give centralised investments an unfair advantage to the detriment of consumers, as demonstrated by the lower costs achievable via significantly higher levels DER. Achieving the levels of DER assumed in the Consumer High DER scenario will therefore require leveling the playing field, particularly with respect to network price signalling and investment planning.
    - **Accurate, forward looking network price signals –** Achieving the levels of DER investment under the Consumer High DER scenario will require establishment of far more accurate network price signals, ideally on a forward looking, nodal, and dynamic, and which reflect the value of consuming DER locally, encouraging efficient consumption and investment patterns. [13]
    - **Recognition of the full range of DER benefits** – Achieving the optimal mix of DER will require the accurate pricing of the full range of network DER benefits from the LV to sub-transmission level, as well as its option[14] value, instead of current industry practice, which considers network investments in isolation, which significantly disadvantages DER economics.

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[13] See AEMC (2021), National Electricity Amendment (Access, Pricing And Incentive Arrangements For Distributed Energy Resources) Rule 2021, https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf

[14] Option value refers to the option of making a different investment in the future under uncertain conditions, including in lower cost DER.

- **Distributed energy resource enablement** – Even if the perfect price signals and investment planning practices were established overnight, the industry is ill-equipped to manage the orchestration of millions of DER devices in order to maintain current levels of system security, reliability and safety. Energeia has identified the following three key enablement measures as being essential:
    - **Holistic network planning –** Current network plans[15] focus on the sub-transmission system, and do not plan the network as a whole, significantly disadvantaging DER based solutions, which are most competitive when considered across the full range of network constraints. Publication of a holistic resource report will also lead to higher, more efficient levels of market investment in DER resource development and operation capabilities and capacity.
    - **Constraint and orchestration systems –** A significant number of constraint and orchestration pilots have occurred over the past 5 years, and DNSP investment proposals increasingly include investments to manage DER constraints and orchestration. However, there is no consensus between consumers, industry and new entrants regarding the necessary future state architecture. A fit-for-purpose, industry consensus future state architecture is essential.
    - **Market systems –** In addition to the network constraint and technical control systems above, a market system is needed to efficiently coordinate the operation of DER across network nodes and interfaces with the National Electricity Market (NEM). As is the case with constraint and orchestration, there are a number of alternative market architectures that could be implemented. A stakeholder[16] consensus based approach is urgently needed to be implemented.
- **Industry incentives –** The NER has established a constellation of performance incentives, however, Energeia's analysis has found that investing in network assets remains the largest incentive by far due to its multiplier effect on the valuation of network businesses.[17] As long as investors maximise their total return by increasing network capital expenditure, they will continue to incentivise executive management to prioritise capital expenditure. The key to incentivising networks to support the achievement of optimal levels of network investment therefore requires:
    - **Delinking network investment from DNSP valuations**. Policymakers and regulators will need to reform the system of economic regulation to effectively break the nexus that demonstrably exists between total returns and network investment. Doing so will unleash DNSPs to effective drive and lead the key measures described in this section.
    - **Linking least cost outcomes for consumers to DNSP valuations**. There are also a range of regulatory measures that could be used to more effectively tie sustainable, long-term shareholder returns to least cost electricity system outcomes for consumers such as the outcomes modelled as part of this study, e.g. approaches pioneered in the U.K and New York.

The above changes are non-trivial, and will require significant political, regulatory and institutional effort achieve. The rationale for driving the necessary changes lies in the expected value of doing so.

The Case for Change

Energeia used our technical modelling outputs to estimate total system costs by scenario across consumers, networks and generators over a 15-year period in discounted present value terms, which are reported in the figure on the following page. Energeia's cost-benefit-assessment (CBA) shows that realising the Consumer High DER scenario would save consumers $25b (by 2035) compared to our modelling of the ISP Step Change

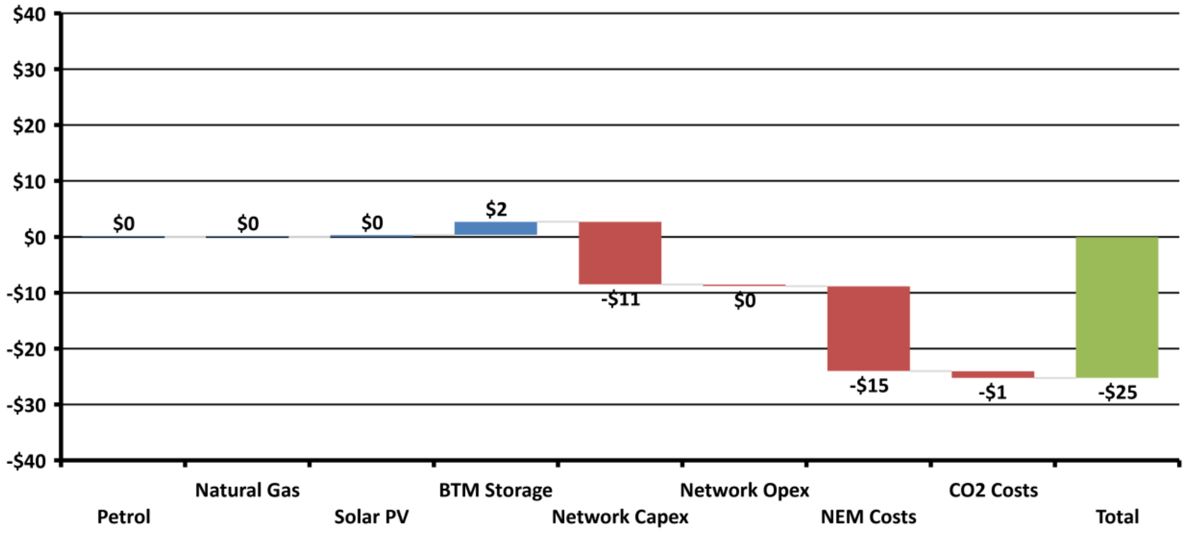
[15] For example, the Distribution Asset Planning Report, or DAPR.

[16] Stakeholders including equal representation by consumer advocates and new entrant decentralised energy system participants.

[17] Networks also identified value-limited incentives and more difficult approval for non-network solutions as a significant barrier.

scenario, mainly due to $11b in lower network costs, and $15b in lower NEM settlement costs, which is partially offset by $2b in higher DER costs.

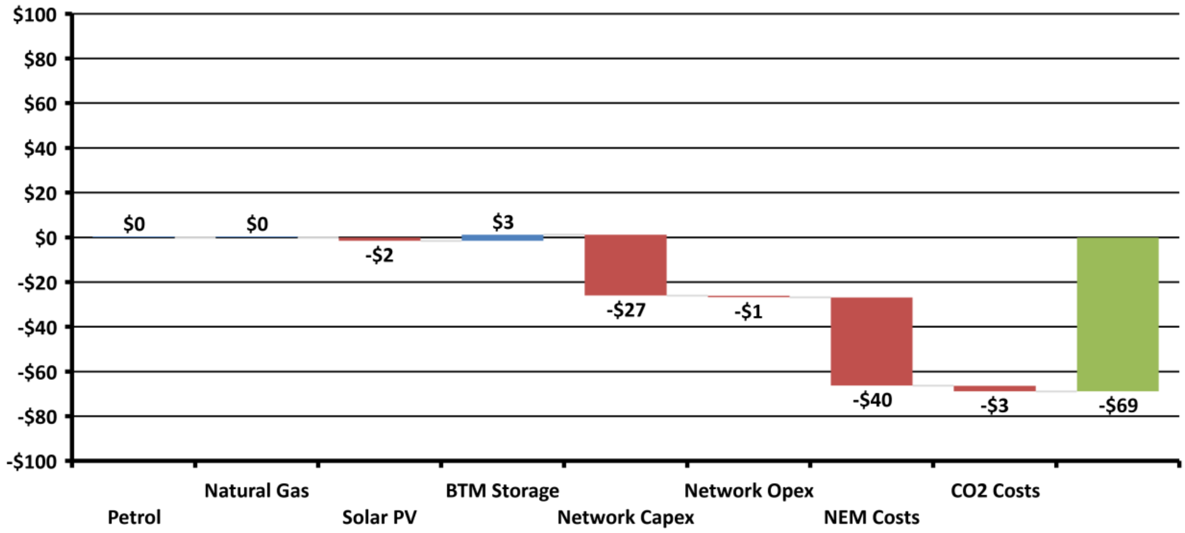
Costs and Benefits of Consumer High DER Compared to ISP Step Change incl. Generation Costs (15 Year)



Source: Energeia modelling

By 2050, the Consumer High DER scenario is $69b less for consumers, driven mainly by $27b in lower network capex costs and $40b in lower NEM settlement costs, partially offset by $3b in higher behind-the-meter storage costs. Rooftop solar PV costs are lower than under the ISP Step Change scenario, despite significantly more rooftop capacity, due to the post 2030 timing of most of the investment.

Costs and Benefits of Consumer High DER Compared to ISP Step Change incl. Generation Costs (30 Year)



Source: Energeia modelling

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Disclaimer

This work was undertaken as part of a project funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

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1 Project Background and Drivers

Australia's Network Transformation Roadmap (NTR) found that up to 45%[18] of all electricity system investment over the period to 2050 would be made behind the meter by consumers or their agents. While this is starting to occur at the generation level, with an estimated 15%[19] of all generation capacity being attributed to behind-the-meter consumer generation, it is not yet the case at the network level, where AEMC found non-network alternatives were being chosen for 0.15% of total investment, and Energeia's own research has found that less than 10%[20] of RIT-D projects in the last 3 years have implemented a non-network alternative.

While consumer investment in rooftop solar PV has been tracking the NTR view of a substantially more decentralised future, trends suggest solar PV could be increasingly[21] curtailed and/or blocked in the future. The Australian Energy Market Operator (AEMO) has called[22] for rooftop solar PV to be limited in the name of energy system security and reliability. In comparison to the NTR, AEMO's modelling of a high DER, low carbon future electricity system under its 'Step Change' scenario for the Integrated System Plan (ISP) sees consumer side investment in rooftop solar PV providing 18 GW less[23] capacity by 2050.

The electricity industry, including key governing, regulatory and market bodies, has been focused on addressing the key barriers to optimal DER investment across a range of initiatives[24]. However, recently completed stakeholder engagement completed for this project has found that these industry initiatives are dominated by centralised electricity system incumbents, both players as well as policymakers, regulators and market operators, in terms of participation and therefore perspective, and that they do not have a clear vision of what an optimal future least cost system looks like for consumers, beyond that of the perspectives of the NTR and the ISP.

Renew is a community-based member organisation that advocates for consumer interests in energy market policy.[25] It is therefore interested in developing the evidence base to identify the role of DER in the optimal future scenario for consumers, the key actions that will need to be taken to achieve it and their sequencing and timing, the roles of each industry group in their implementation, and perhaps most importantly, the net benefits of doing so and how they will be distributed across industry stakeholders, especially vulnerable consumers and those without DER.

Renew, with funding by Energy Consumers Australia (ECA), undertook a project in 2019[26] to identify the key barriers to the efficient investment in DER and the least cost solutions for addressing them. A key finding[27] of that project was that a whole-of-system approach was needed to determine the optimal level of DER investment, and

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[18] Energy Networks Australia (2017), 'National Transformation Roadmap', https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/, pg. i

[19] AER (2020), 'State of the Energy Market', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Chapter%201%20A3%20spread.pdf

[20] Energeia research of pre-2019 DAPRs and RIT-Ds across the National Electricity Market

[21] As alluded to in SA Power Networks (2019), 'LV Management Business Case: 2020-2025 Regulatory Proposal': https://www.aer.gov.au/system/files/Attachment%205%20Part%207%20-%20Future%20Network.zip, pg. 6, and supported by modelling results from L. Ochoa, A. Procopiou, University of Melbourne (2019), 'Increasing PV Hosting Capacity: Smart Inverters and Storage': https://resourcecenter.ieee-pes.org/education/webinars/PESVIDWEBGPS0010.html

[22] AEMO has called for DNSPs to provide real time visibility requirements for distributed solar PV to better enable curtailment , see AEMO (2020), 'Renewable Integration Study: Stage 1 Report', https://www.aemo.com.au/-/media/files/major-publications/ris/2020/renewable-integration-study-stage-1.pdf

[23] AEMO (2020), '2020 Integrated System Plan', https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en

[24] As highlighted in Section 1.3 of Energeia (2019), 'Distributed Energy Resources Enablement Project – Discussion and Options Paper', https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

[25] See Renew's mission statement, available at: https://renew.org.au/what-we-do/advocacy/consumer-focused-energy-markets/

[26] Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

[27] See Section 5.2 of Renew (2020), 'Enabling Distributed Energy in Electricity Networks', https://renew.org.au/wp-content/uploads/2020/06/RenewDER.pdf

the optimal solutions for enabling it. Stage II of the project, which includes this report, seeks to address the analytical gaps identified in Stage I, as well as those identified via stakeholder consultation.

The following sections summarise key related work that has given rise to the need for this project, namely Australia's key DER scenarios of the future, value-of-DER studies, a summary of the project goals and objectives and key modelling methodology requirements.

1.1 Key Distributed Energy Resource Uptake Scenarios

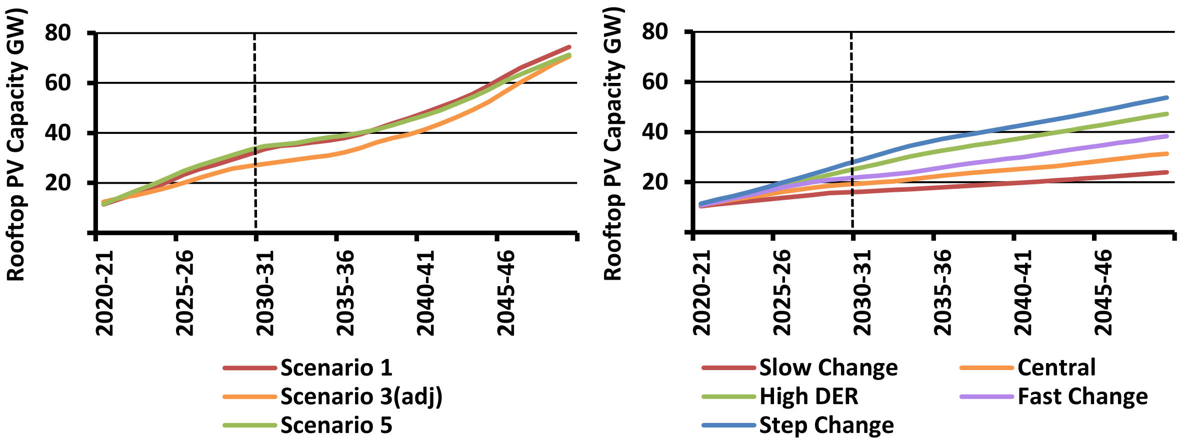
ENA's NTR issued in 2016 remains the most comprehensive, whole-of-system assessment of the role and impact of DER on the long-term interests of consumers and the wider industry. AEMO's bi-annual ISP and the associated planning process is another key source of DER uptake scenarios, however, the modelling is not as comprehensive as the NTR due to the lack of distribution network modelling, for example.

The NTR scenarios were developed by a multidisciplinary team[28] led by CSIRO and the ENA, while AEMO's scenarios are developed by AEMO. It is worth noting that the NTR scenarios were developed to help inform network investment decision making, while AEMO's scenarios have been developed to help inform utility scale generation, storage, and interconnector investments to 2050.

Energeia reviewed both sources of industry scenarios regarding DER uptake potential to inform our own consumer-focused scenario development process. The results of our review are reported in Figure 1, which compares the NTR Scenarios on the left to the latest ISP scenarios on the right. The comparison shows the ISP's comparable forecasts to be significantly lower than the NTR's for rooftop PV and storage by 2050.

Energeia notes that only the Step Change scenario in the current AEMO ISP forecasts is comparable to the rooftop solar PV forecast for 2030 in the NTR for Scenario 3(adj).

Figure 1 – CSIRO/ENA's (Left) vs. AEMO's (Right) Rooftop Solar PV Capacity Forecasts in the NEM

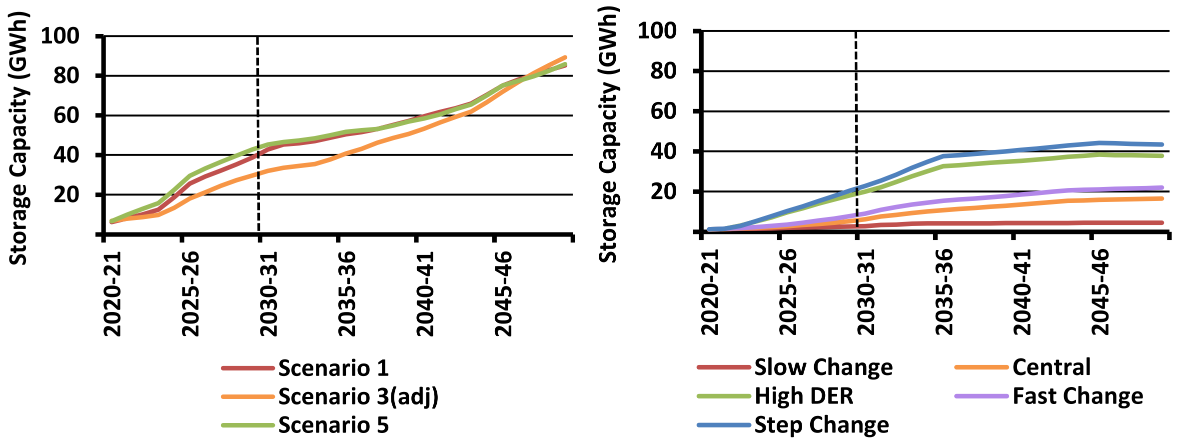


Source: ENA NTR (2016), AEMO Inputs and Assumptions to 2020 ESOO (2020)

Figure 14 on the following page shows AEMO's 2020 ISP forecasts of storage under the High DER and Step Change scenarios seeing less than 20 GWh of storage capacity by 2030 compared to the 32-45 GWh of behind the meter storage forecast in the NTR forecasts.

[28] Energeia was a member of the modelling team and supported the translation of the scenarios into modelling parameters.

Figure 2 – CSIRO/ENA's (left) vs. AEMO's (right) Embedded Storage Capacity Forecasts in the NEM



Source: ENA NTR (2016), AEMO Inputs and Assumptions to 2020 ESOO (2020)

In summary, the key DER uptake forecasts in Australia have been developed by the market operator or the network industry to inform distribution network and wholesale market investment decision making, rather than to identify a future consumer-optimised electricity system. Also, the ISP scenarios and resulting analysis is limited by its modelling scope, which excludes the costs and benefits of DER within the distribution networks, which account for 40-50%[29] of consumer bills in the NEM.

1.2 Key Distributed Energy Resources Studies and Analyses

Given the high level of expected DER adoption in the period to from 2020 to 2030, and the related regulatory, technical and consumer behaviour factors that need to be considered to integrate that level of DER into the grid, market bodies have commenced a number of DER integration studies and programs. These initiatives are summarised in Table 1, which shows recently completed DER projects identified from Energeia's research.

Table 1 – Recently Completed DER Studies

Project	Year	Sponsor	Author	Purpose and Objective
Pricing for the Integration of DER	2020	ARENA	Oakley Greenwood	How can cost reflective prices assist in the economically efficient integration of DER into the grid
Distributor's incentives to efficiently incur DER export expenditure	2020	IPART	Houston Kemp	Assessment of regulatory reform options to unlock net benefits of DER enablement
Grid vs. Garage	2020	ARENA	AECOM	Comparison of different battery storage deployment models
Assessment of Open Energy Network Frameworks	2020	AEMO / Open Energy Networks	Baringa	Cost and benefit assessment of four different DSO frameworks
Value of DER	2020	AER	Cutler Merz / CSIRO	Development of a methodology for DNSPs to assess the value of DER from investments in hosting capacity
Feasibility of Export Capacity Obligations and Incentives	2020	AEMC	CEPA	Assess the various options for DNSPs to optimise DER export capacity to maximise long-term consumer net benefits
Value of Optimised Flexible DER	2020	AER	Baringa	Quantify the value of optimising flexible DER and other loads (e.g. HVAC and pool pumps) for households

Source: Energeia

[29] AER (2020) 'State of the Energy Market 2020', https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202020%20-%20Full%20report%20A4.pdf, pg. 17

Energeia has reviewed each of these studies for which areas of the DER enablement value stack that they targeted, the barriers that they addressed and the solutions that they investigated. As shown in Table 2, the various studies address different barriers, investigate different solutions, and/or cover different components of the DER value stack.

Table 2 – Analysis of Recently Completed DER Studies

		DER Integration Pricing	DNSP Incentives	Grid vs. Garage	Open Energy Networks CBA	Value of DER	Export Capacity Incentives	Value of Optimised and Flexible DER
Value Stack Modelling								
Consumer Bill Minimisation	Consumer Self Consumption		✓	✓	✓	✓		✓
	Consumer Exports		✓	✓	✓	✓	✓	✓
Network Expenditure	Network Augmentation Expenditure	✓		✓	✓	✓		
	Network Replacement Expenditure	✓		✓		✓		
Network Operation	Network Sub-transmission							
	Network High Voltage							
	Network Low Voltage	✓			✓	✓	✓	
Wholesale Market Operation	RERT/Retailer Obligation Revenues	✓						
	Wholesale Market Revenues	✓		✓	✓	✓		✓
	Ancillary Services Revenues			✓	✓	✓		✓
Barriers and Solutions								
Policy and Regulatory Factors	Technical Regulation[30]	✓	✓	✓	✓	✓	✓	
	Economic Regulation	✓	✓	✓	✓	✓	✓	
	Pricing / Tariffs	✓	✓	✓				
	Market Design				✓			
Technical Factors	Technical Constraints	✓	✓	✓	✓	✓		
	Technical Solutions	✓	✓	✓	✓			✓
	Cost Recovery			✓				
Consumer Factors	Consumer Behaviour / Engagement		✓	✓			✓	
	Consumer Experience							
	Consumer Protection							
	Consumer Equity		✓	✓		✓	✓	

Source: Energeia

Energeia's review of studies to date has identified that none of them appear to attempt to determine the electricity system configuration that maximises the long-term benefits for consumers, given the cost, reliability, security and safety of the electricity supply in the national electricity market, i.e. the National Electricity Objective (NEO).

[30] Technical Regulation includes Connection, Metering, B2B and Inverter Standards

2 Scope and Approach

Energeia was engaged by Renew to develop and implement a whole-of-system modelling methodology that would support the achievement of Renew's DER enablement project Stage II objectives, namely, identifying the optimal future state for consumers that best meets the National Electricity Objectives (NEO), the role of DER, and level of DER enablement needed to realise it. Importantly, the ECA Board required Energeia's modelling methodology and results to be reviewed by an independent expert selected by Renew.

Energeia's approach to developing and implementing a whole-of-system modelling methodology to identify the optimal consumer-focused future electricity system scenario involved:

- **Developing consumer focused scenarios of the future –** Energeia developed a consumer focused high DER and low carbon scenario of the future to compare with the ISP Step Change scenario.
- **Modelling the optimised future state for all customers** – Energeia ran our customer optimisation and generation models to identify the least cost mix of DER, network and generation over time.
- **Identifying the key barriers and drivers to the optimal future state** – Based on our learnings from the modelling, Energeia identified key barriers to the optimal future state and potential solutions
- **Developing the case for changing to the optimal future state –** The outputs from our technical models were brought together in a whole-of-system model to compare each scenarios overall costs
- **Engaging, consulting and validating with stakeholders and subject matter experts (SMEs)** – Energeia engaged with key stakeholders and SMEs throughout the process accordingly.

Energeia notes that this final report incorporates the feedback received from stakeholders and subject matter experts on our draft report.

3 Consumer Focused Scenarios

Australia's long-term transmission and generation investment program is driven by scenarios developed by AEMO as part of the ISP development process. These scenarios can also impact DNSP network investment via their incorporation of AEMO's connection point and peak demand forecasts.

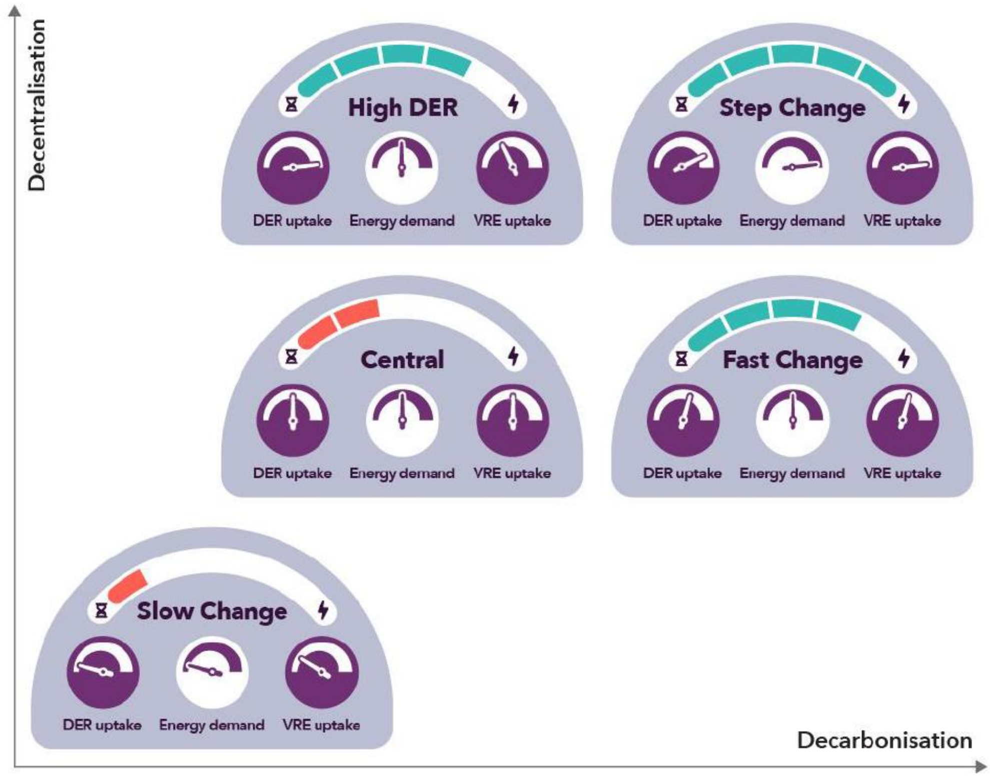
The ISP includes scenarios[31] that appear in AEMO's diagram (see Figure 3 below) to test the upper limits of DER in the electricity system, however, the impact of DER on overall costs to consumers, and whether these are optimal levels of DER uptake, is not addressed in the ISP, and it is therefore not possible to determine.

Energeia therefore developed two scenarios that sought to test the costs and benefits of AEMO's high DER scenarios against a consumer benefits focused scenario. This section summarises AEMO's scenarios, and then reports on the scenario development process we followed, and the resulting scenarios we have modelled.

3.1 AEMO's Integrated System Plan Scenarios

AEMO's long-term planning scenarios from its latest ISP development process are summarised in the figure below. They have been designed to reflect a range of plausible scenarios of the future, to ensure that AEMO's long-term system plans are robust.

Figure 3 – Integrated System Plan Scenarios



Source: AEMO, 2020 Inputs, Assumptions and Scenarios Report (August 2020)

The Inputs, Assumptions and Scenarios report (the Scenarios Report) does not explain how each scenario's uptake levels have been determined or whether they reflect economically and/or socially optimal levels of DER uptake. For the two high DER scenarios, the report states:

- The **High DER** scenario reflects a more rapid consumer-led transformation of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes

[31] The High DER and Step Change scenarios see the highest levels of DER adoption.

reduced costs and increased adoption of distributed energy resources (DER), with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.

- The **Fast Change** scenario reflects a rapid technology-led transition, particularly at grid scale, where advancements in large-scale technology improvements and targeted policy support reduce the economic barriers of the energy transition. This includes coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated exit of existing generators, and integration of transport into the energy sector.

Table 3 details the forecast DER under the Step Change scenario. The resulting wholesale energy costs under each ISP scenario are not published, nor are the impacts of each scenario on network costs. Energeia therefore modelled these costs by configuring our modelling tools with ISP scenario assumptions where available to compare with the consumer-focused scenario costs. The key assumptions used to model the AEMO and consumer scenarios are summarised below.

3.2 Scenario Development

The objective of this study was to identify optimal levels of DER investment to minimise costs to consumers over the study period holding system security, reliability and safety constant.

The purpose of the scenario development process was to develop scenarios that could inform the national dialogue, including the ISP development, DIEP DER integration and ESB market design processes, regarding the overall optimal mix of resources for consumers, including the optimal mix of DER.

Due to the potential impact of the significant issues Energeia identified[32] with the assumptions used in the ISP, as well as key challenges encountered in modelling the high level of DER uptake, Energeia shifted from the original scenario design approach, which relied on published DER technology prices, network LRMCs and building electrification assumptions, to one that used our own estimates for these key scenario drivers.

3.3 Scenario Design

The scenario design ultimately adopted for modelling the optimal level of DER adoption, and its associated costs and benefits are summarised in the table below. The key differences between the scenarios are the assumed DER pricing levels, rate of DER adoption, size of DER adopted and network LRMCs.

Building electrification rates assumed under the Step Change scenario were not able to be determined from the documentation. Instead, and to make the scenarios more comparable, Energeia assumed a common rate of building electrification, and used the same transportation electrification profile across both scenarios.

The level of rooftop solar PV and water heating control assumed in the Step Change scenario were also unable to be identified, and a common assumption was again used across the scenarios. A common assumption for managed EV charging and storage participation (100%) was also used due to model constraints.

[32] See section 4.1.2 for more information regarding the key issues and Energeia's approach to dealing with them.

Table 3 – Scenario Design

	Scenario Name AEMO Step Change	Consumer High DER
Key Scenario Drivers		
Distributed Technology Prices		
Solar PV	AEMO Step Change	Trend
Storage	AEMO Step Change	Trend
Distributed Technology Adoption Rates		
Solar PV	39% by 2030, 49% by 2040	90% by 2030, 93% by 2040
Storage	14% by 2030, 24% by 2040	80% by 2030, 90% by 2040
Distributed Technology Adoption Sizes		
Solar PV	AEMO Step Change	Economically Optimal
Storage	AEMO Step Change	Economically Optimal
Electrification Rates		
Buildings	80% by 2030, 90% by 2040	80% by 2030, 90% by 2040
Transportation	AEMO Step Change	AEMO Step Change
DER Management		
Water Heating	100%	100%
Vehicle Charging	100%	100%
Storage	100%	100%
Solar PV	100%	100%
National Electricity Market		
Fuel Prices	AEMO Step Change	AEMO Step Change
Technology Costs	AEMO Step Change	AEMO Step Change
Networks		
LRMC	Published	Estimated

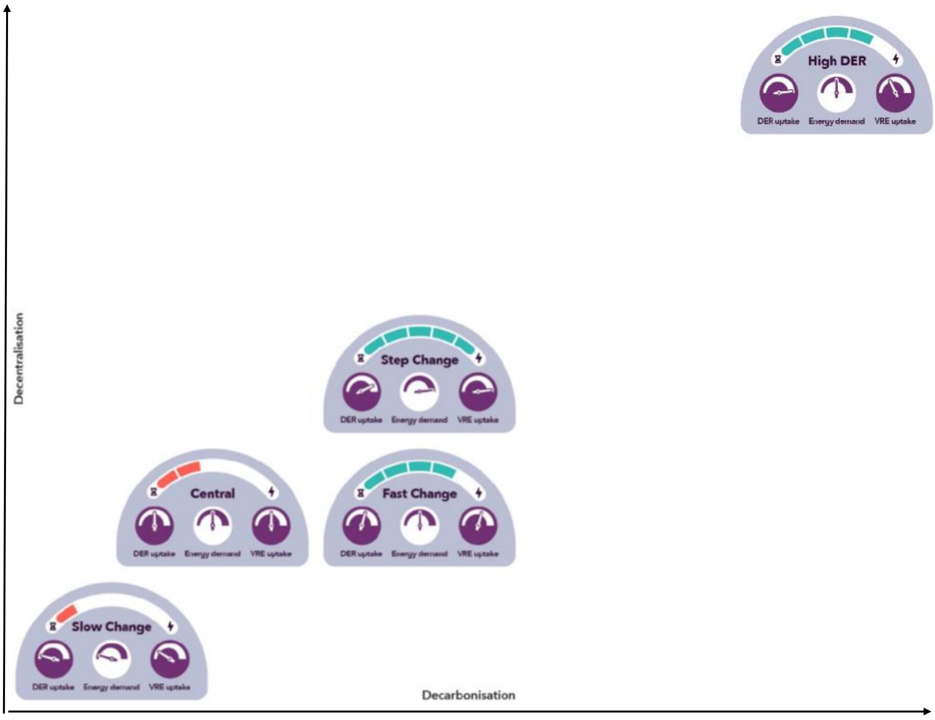
Source: Energeia

Although it means that our modelling outcomes are likely to vary from AEMO's own modelling outcomes, using common DER management assumptions allows for more comparable modelling results, allowing us to better identify the impact of higher DER adoption, given a high level of DER management.

Energeia hopes to model a wider range of scenarios in future to better tease out the discrete impacts of key scenario assumptions, including the role of DER pricing, DER management, building electrification rates, transportation electrification rates and network LRMCs.

The figure on the following page illustrates where Energeia sees the Consumer High DER scenario sits within the scenario framework developed by AEMO for the ISP. We have positioned the Consumer High DER scenario relative to the ISP Step Change scenario on the vertical axis based on the relative level of DER adoption and on the horizontal axis based on the relative level of CO_2 emissions. The Consumer High DER scenario sees more than double the level of BTM storage and around 75% more rooftop solar PV capacity, and as a result of the latter, achieves about the same relative reduction (75%) in electricity system emissions.

Figure 4 – ISP Scenarios including Consumer Focused High DER Scenario



Source: AEMO, Energeia

4 Optimal Future State for Consumers

Energeia modelled the optimal DER configuration for key customer classes over time given scenario assumptions to develop customer weighted estimates of the DER adoption and sizing, coincident maximum demand, grid consumption and hourly load profiles to 2050 by scenario.

Although Energeia has previously modelled high levels of DER adoption, for example for the National Transformation Roadmap (NTR) completed in partnership with CSIRO and the ENA, this is the first time we have done so using our end-to-end modelling system, including wSim, our National Electricity Market (NEM) simulation tool. We found that current assumptions regarding operational demand and generator bidding behaviour is ill suited to a high DER future, and we had to retool our assumptions and modelling accordingly.

Energeia specialises in modelling consumer behaviour and its impact on the electricity system. However, for this study we have undertaken the modelling on an economic rather than behaviour basis to better identify and focus on the associated, fundamental costs and benefits. By estimating the size of the prize without considering the associated barriers, it can be used to inform decision-making regarding the prioritisation of any policy, regulatory, industry and institutional reforms needed to achieve the identified optimal levels of DER investment.

The key findings from our modelling include:

- The optimised rate of DER adoption is lower than the current rate of adoption, but increases over time to approximately current rates
- Optimised DER adoption reduces network capacity requirements by 23%
- Significant curtailment of solar PV and wind occurs, and it appears that rooftop PV that will get curtailed first[33], at least until 2030 when the Renewable Energy Certificate (REC) scheme expires
- Wholesale market clearing prices become increasingly negative, particularly during periods of high solar PV generation, but also during periods of relatively low load
- There is still economic value in solar PV exports on average, especially if negative prices are avoided
- Managed DER plays a major role in shifting load to the middle of the day and minimising curtailment

The following sections report on the modelling methodology, key inputs and assumptions and outputs for the customer, network and wholesale market modelling completed for this study.

4.1 Consumers

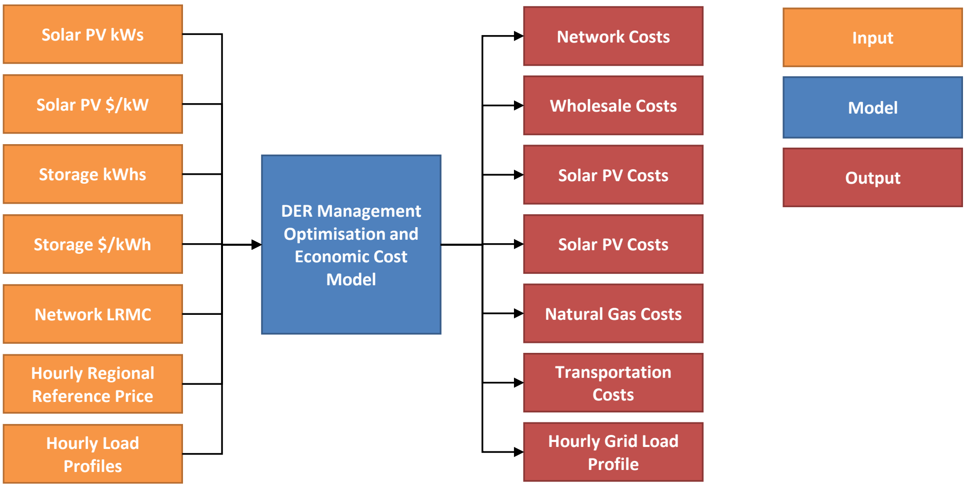
Energeia modelled the optimal DER adoption and sizing and the associated system and network loads using our customer cost-optimisation model, configured using the scenario parameters and key inputs and assumptions detailed below. For the ISP Step Change scenario, we determined customer solar PV and storage uptake and sizing using published AEMO figures. The outputs were fed into our scenario network and system load model, which was used to drive our network and wholesale cost models.

4.1.1 Methodology

Energeia adapted its customer cost optimisation model to provide the configuration flexibility needed to identify the optimal DER configuration for a given scenario. The key inputs and outputs from the model are shown in the simplified diagram below. Each of the inputs is driven by the scenario assumed, except for solar PV and storage capacity, which is optimised to deliver the least cost outcome for the consumer.

[33] This is post-introduction of remotely curtailable rooftop solar PV inverters, as is the case in South Australia.

Figure 5 – Consumer Modelling Diagram



Source: Energeia

4.1.2 Key Inputs and Assumptions

Energeia's approach to modelling the optimal DER configuration for a given consumer type, annual hourly load profile (including transport and building electrification), DER management functionality, wholesale and network costs, is summarised in the sections below.

4.1.2.1 Forward Looking Costs

Energeia's modelling assumes forward looking costs only, which is consistent with economic theory regarding efficient investment decision-making.

Sunk Cost Fallacy

A sunk cost is a cost that has already occurred and cannot be recovered by any means. Sunk costs are independent of any future event and should not be considered when making investment or project decisions. Only relevant costs (costs that relate to a specific decision and will change depending on that decision) should be considered when making such decisions.

Network costs paid by the consumer are therefore calculated by multiplying the network LRMC by the customer's contribution to network peak demand – no sunk costs[34] are included.

4.1.2.2 Network Long-Run-Marginal-Cost

Energeia's analysis of DNSP LRMC's found a wide range of approaches to determining the costs that feed into DNSP LRMC calculations, which range from 0 to over 100% of AER approved costs. In some cases, we were unable to determine the level of costs included from DNSP reports and models. Given these values drive the optimal mix[35] of DER, network and generation costs, it is important that they be as accurate as possible.

[34] All network tariffs currently include sunk costs, however, their allocation to specific pricing components varies.

[35] Higher LRMCs will mean networks are relatively more expensive, making DER more competitive.

Figure 6 – Summary of Selected DNSP LRMC Estimation Methods, Inputs and Assumptions

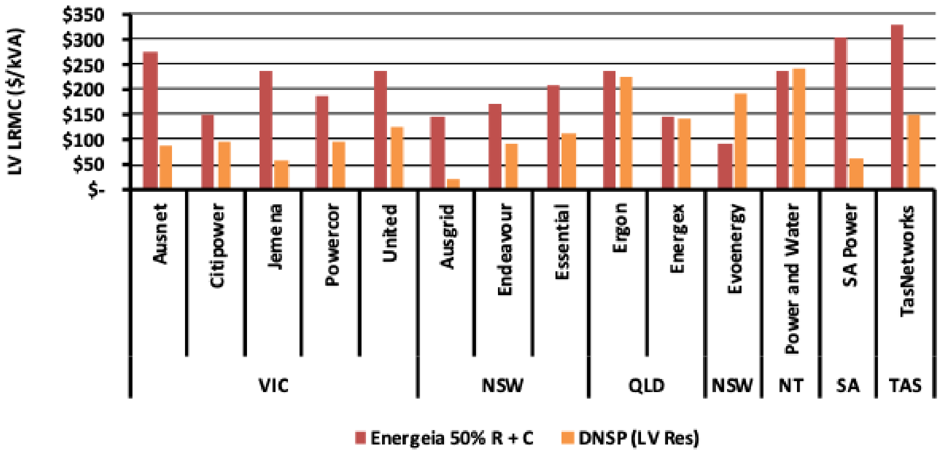
		VIC			NSW			ACT	SA
		AusNet	Jemena	CitiPower / Powercor	Ausgrid	Endeavour	Essential	Evoenergy	SA Power
Demand incl. in LRMC	P10/P50/Raw	P50	Raw	Raw	P50	P50	Raw	Raw	P10
	NCMD/CMD	NCMD	CMD	NCMD	-	NCMD	CMD	CMD	CMD
	NCMD Basis	ZS	-	ZS	-	ZS	-	-	-
% Expenditure incl. vs. AER FD	Repex	10%	0%	0%	1%	142%	10%	0%	9%
	Augex	0%	6%	174%	40%	27%	18%	89%	69%
	Connex	0%	21%	0%		43%		109%	0%
	Opex %	1.0%	4.3%	0.5%	2.0%	2.0%	-	2.0%	1.5%-2%
Time	LRMC Start Year	FY20	FY19	CY16	FY19	FY19	FY18	CY18	FY16
	Actual Years in LRMC	FY20	CY19-20	CY16-20	FY19-20	FY19	FY17-19	CY18	FY16-20
	Forecast Years in LRMC	FY21-30	FY22-29	CY21-25	FY21-38	FY20-28	FY20-32	CY19-27	FY21-38
	Total Years in LRMC	11	11	10	20	10	15	10	23

Source: DNSP LRMC Models, DNSP Regulatory Information Notices
Note: NCMD = Non-coincident Max Demand, CMD = Coincident Max Demand, P10 = demand event with 10% chance of occurring, P50 = demand event with 50% chance of occurring, Raw = the actual demand event that occurred

While the Rules are clear as to the definition of long-run, which is the period over which all costs become variable[36], they are not specific about which costs may be excluded from LRMC calculations. Energeia's view is that all investment needed to meet peak demand should be included in the LRMC calculation for peak demand, leaving out customer driven and minimum unavoidable costs, e.g. for executive management, an office, etc.

Energeia developed estimates of LRMC using DNSP data supplied in Regulatory Information Notices (RINs) that assumed 50% of all augmentation, replacement and connection capital. The resulting LV LRMCs are reported in the figure below, alongside DNSP reported LRMCs, and are on average about twice as high. Moving to LRMCs that reflected 100% of capex (less customer driven capex), would roughly double these numbers.

Figure 7 – Energeia Estimates of Selected DNSP LRMCs



Source: DNSP LRMC Models, DNSP Regulatory Information Notices, Energeia modelling

[36] Long run marginal costs is defined as the cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied. AEMC, 'National Electricity Rules: Chapter 10', https://energy-rules.aemc.gov.au/storage/rules/274e73dc5472da1c64db1918f770bea2b37f0793/assets/files/NER%20-%20v169%20-%20Chapter%2010.pdf

Energeia used the DNSP published LRMCs for the ISP Step Change scenario and the Energeia estimated LRMCs for the Consumer High DER scenario.

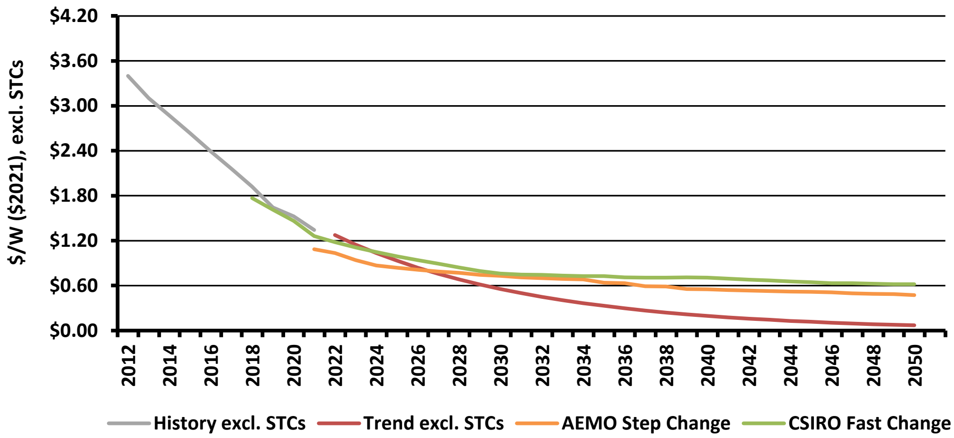
Energeia has assumed that LRMC's do not change in real terms over the modelling period. In actuality, the incorporation of new, lower cost factors of production like DER will lower the LRMC.

4.1.2.3 Distributed Energy Resource Technology Prices

Energeia originally planned to use the technology price forecasts assumed in the ISP Step Change scenario, however, upon review we found that they did not fit well with historical trends. Again, given that technology price forecasts are a key driver of the optimal future mix of DER, network and generation investment, Energeia developed estimates based on the continuation of recent historical trends.

The figure below compares the solar PV price forecasts assumed in the ISP's Step Change and the CSIRO Fast Change against a best fit trend line. While Energeia acknowledges that many will have reservations of a trend continuing for 30 years, today's solar PV prices were also inconceivable in 2010. Our view is that the actual historical rate of cost reduction is a key scenario to be considered by prudent system and network planners.

Figure 8 – Residential Solar PV Cost Outlook by Scenario

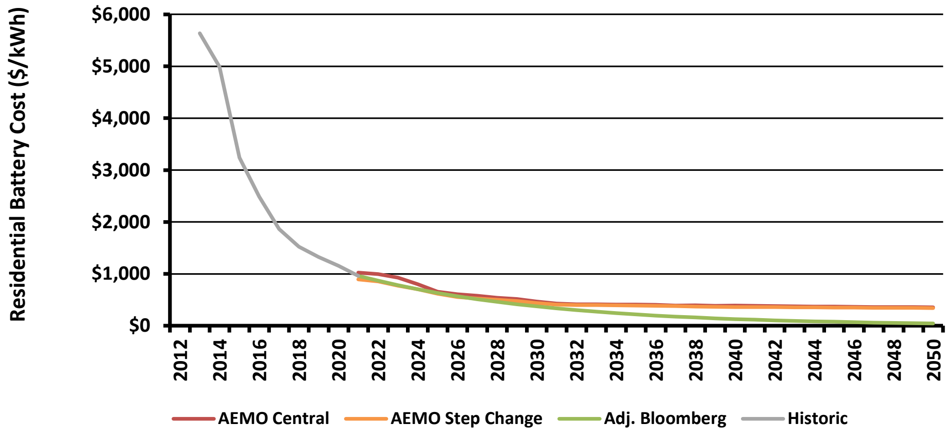


Source: Energeia research, CSIRO, AEMO

ISP Step Change price forecasts for behind the meter (BTM) storage technology are reported in the figure below. As is the case with rooftop solar PV prices, the ISP Step Change scenario's BTM storage price forecasts change their trajectory by 2022 and are largely flat over most of the modelling period from 2032 to 2050.

Energeia was able to identify a public domain battery module cost reduction forecasts from Bloomberg New Energy Finance (BNEF), which more closely fit the historical rate of BTM battery cost reductions. Energeia developed a forecast BTM battery price by applying the BNEF forecast to the current BTM battery price (denoted as Adj. Bloomberg below).

Figure 9 – Residential Battery Storage Cost Outlook by Scenario



Source: Energeia research, AEMO, Bloomberg

Energeia applied the ISP Step Change DER technology prices to the ISP Step Change scenario and the Energeia developed technology price forecasts (i.e. Adj. Bloomberg) to the Consumer High DER scenarios.

4.1.2.4 Customer Segments

Energeia developed estimates of hourly load profiles for residential, LV connected and HV connected businesses using a combination of load profiles, electricity and gas consumption by end use, and appliance stock sourced from the public domain.

The key residential profiles were:

- **Typical load profile** – This was developed by weighting our database of residential premise load profiles by reported end use consumption.
- **Typical load profile with 100% electrified end uses**[37] – This was developed by re-weighting our residential load profiles assuming 90% of gas moved to heat pump appliances, the rest to resistive.
- **Typical load profile with electrified transportation** – Vehicle charging profiles were developed based on transportation survey data assuming drivers plugged in when arriving home in the evening.
- **Typical load profile with both electrified end uses and transportation** – These profiles reflected the electrified building profile combined with the vehicle charging profile.

The profiles were scaled to reflect average consumption in each state based on DNSP RIN data.

The figures on the following page display the average summer load profile for each of the residential consumer segments modelled in NSW. Customer load profiles were varied for each state based on differences in end use consumption, appliance stock, and average annual sales per customer. Optimal economic rooftop solar PV and battery storage are zero in 2021 in NSW, however, they increase over time as reported later in this chapter.

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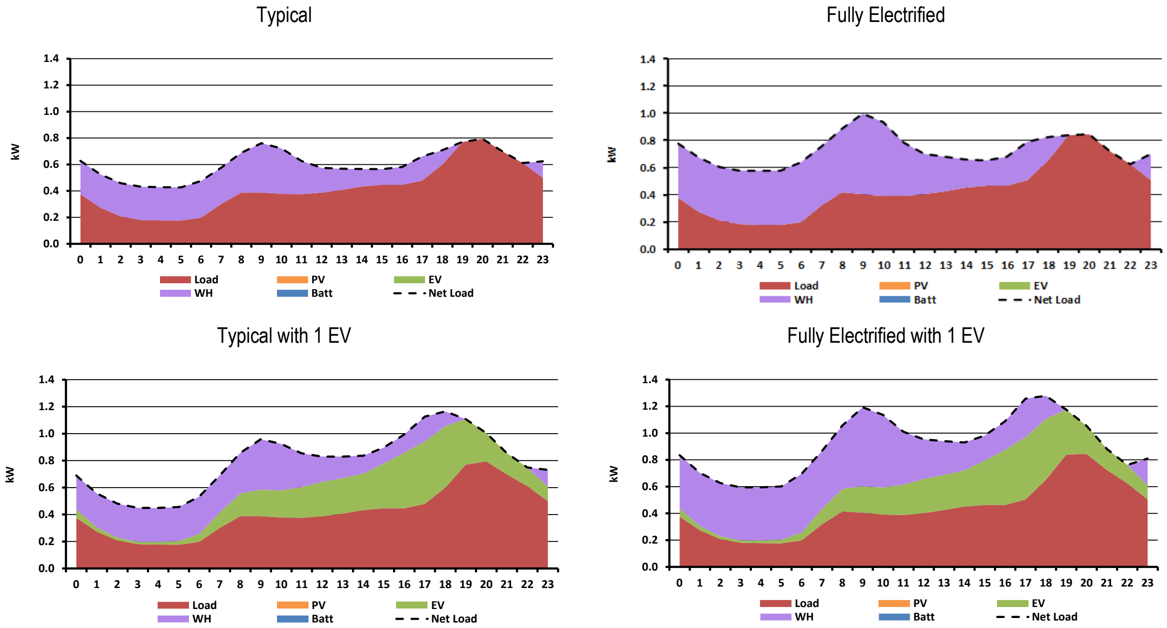
[37] Building electrification means no natural gas for water heating, space heating or cooking.

Figure 10 – VWA Residential Load Profiles by Segment (2021, NSW)



Source: CSIRO, Ausgrid
Notes: EV = Electric Vehicle Load, PV = Rooftop Solar PV, WH = Water Heating Load, Batt = Battery Load

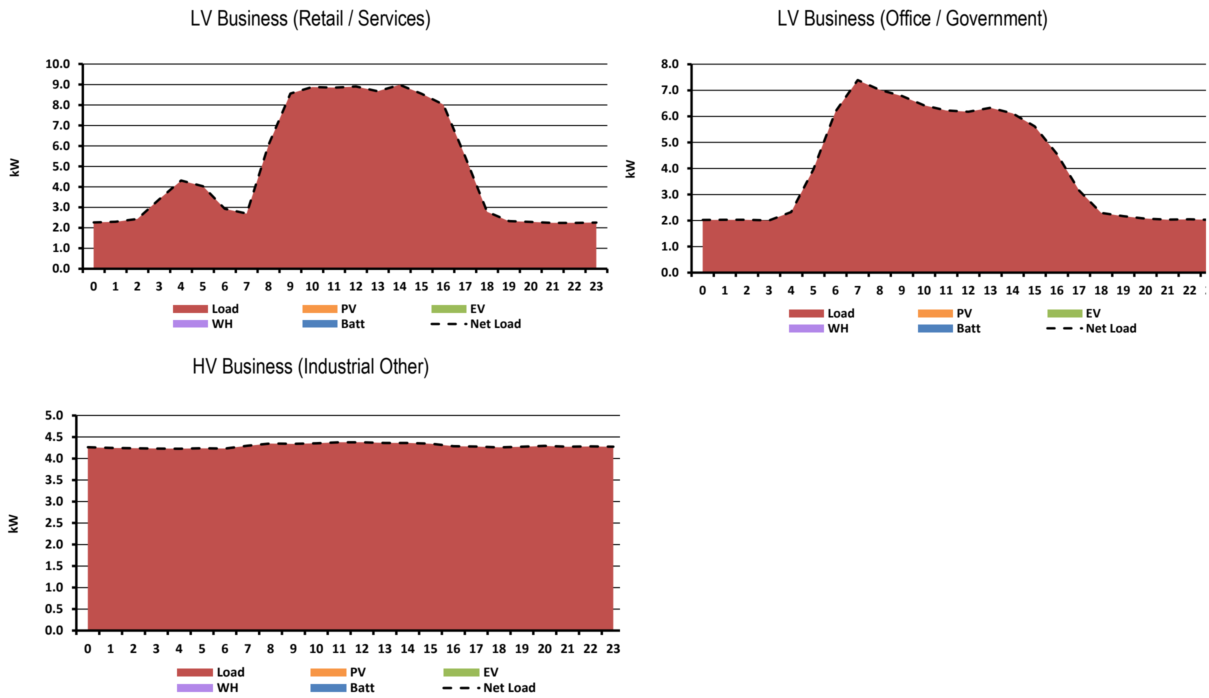
The key business profiles were:

- **Typical LV business profile** – This was developed by averaging an office and retail premise from our database of business load profiles, scaled to the average LV business consumption per state.
- **Typical HV business profile** – This was based on the average industrial profile from our database of hourly consumption profiles gathered from the public domain.

Energeia did not model the impact of building or transportation electrification on business profiles and acknowledges that at least workplace charging is likely to be a significant additional load over time. Water heating load management was also not modelled for business profiles.

The figures below display the average summer load profile for each of the commercial and industrial segments modelled in NSW for LV and HV customers. Commercial load profiles were varied for each state based on differences in average annual sales per customer. Each of the profiles below is normalised to 40 MWh so that the differences in the load shape may be more easily understood.

Figure 11 – VWA Business Load Profiles by Segment (2021, NSW)



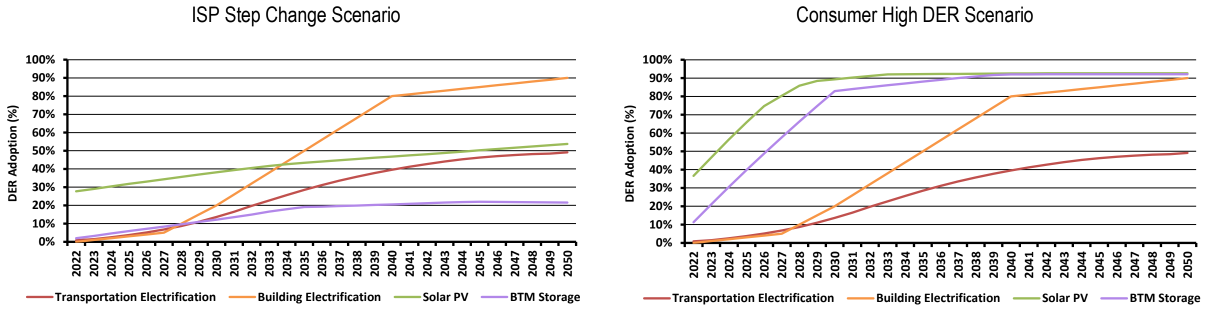
Source: CSIRO

4.1.2.5 DER and Electrification Adoption Rates

Energeia modelled DER, building electrification and transportation electrification rates on a scenario basis, which is displayed in the figure on the following page. Energeia developed the DER adoption profile for the Consumer High DER Scenario to test the impacts of a relatively rapid deployment of DER.[38] The building electrification profile we developed to be consistent with the relatively high CO2 reduction pathway of the ISP Step Change scenario. The transportation electrification uptake profile is based on the ISP Step Change scenario.

[38] Energeia plans to test alternative deployment profiles in future work.

Figure 12 – DER, Building Electrification and Transport Electrification Assumptions



Source: CSIRO, Energeia

Energeia notes that the optimal rate of DER deployment would likely follow network asset investment timing, subject to the lead times needed to deploy DER given customer acceptance rates. This would lead to just-in-time DER asset deployment, pushing out DER investment to the last possible moment and avoiding unnecessary funding costs. As the DER resource development industry matured, Energeia expects lead times to shorten.

4.1.2.6 DER Management

Energeia's modelling assumes 100% management[39] of DER including rooftop PV inverters, BTM storage, water heating and electric vehicles under both scenarios, with specific management assumptions as follows:

- **Solar PV** – Rooftop solar PV is automatically curtailed where it could lead to system instability, e.g. by reducing grid demand below minimum stable thermal generation levels
- **Water Heating** – Water heating is managed each day to soak up as much excess solar PV as possible and to avoid contributing to peak demand
- **Electric Vehicles** – Vehicle charging is also managed each day to soak up as much excess solar PV as possible and to avoid contributing to peak demand
- **BTM Storage** – Storage is also managed each day to soak up as much excess solar PV as possible and avoid contributing to peak demand

Lower levels of DER management may be more realistic, however, the purpose of the Consumer High DER scenario is to test the limits of DER costs and benefits to inform prioritisation of effort to address key barriers including consumer program enrolment, tariff design and real-time markets and distribution system operation.

4.1.3 Optimised Rooftop Solar PV and BTM Storage Configuration

Energeia's consumer cost optimisation model identified the lowest cost DER, network and wholesale market solution in a given year for a given scenario, including natural gas and transportation costs[40], for a representative household.

The table below reports on the results of the optimisation modelling for NSW[41] for each year by selected consumer segment and electrification scenario.

Energeia's optimisation modelling found that the optimal sizing of rooftop solar PV to be 2 kW for new dwellings in 2025, which is below the current actual solar PV sizing of around 6 kW[42]. Energeia notes that solar PV sizing could change significantly over the next few years due to an increase in the frequency of negative pricing, and/or curtailment requirements. By 2030, the optimal size of solar PV stays at 2 kW for the average residential

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[39] DER management means the orchestration of DER resources to minimise economic costs.

[40] However, it should be noted that natural gas and transportation costs do not vary across the scenarios.

[41] Modelling results for all states and consumer segments are reported in the appendices.

[42] 6 kW is based on analysis of solar registry data from APVI, https://pv-map.apvi.org.au/postcode

consumer and 6 kW where they are fully electrified in terms of end uses and transportation. By 2040, optimal solar PV capacity rises to 6 and 8 kW for base and electrification consumer segments, respectively.

In the case of BTM storage, the optimal size of storage at 2 kWh in 2025 is far below the actual average size of storage being bought, due in part to the limited products available in this size. Optimal storage sizing does not increase from 2 kWh until 2040, when falling costs and rising rooftop PV capacity cause it to jump to 4 kWh for the average consumer without electrification, and 6 kWh for the average consumer with full, building and transport, electrification. By 2050, the optimal level of BTM storage increases for both segments to 10 kWh.

Table 4 – Optimal Solar PV and BTM Storage Configurations for Selected Residential Segments (NSW)

	2025	2030	2040	2050
Optimised DER Configuration - No Electrification				
PV (kW)	2	2	6	10
ES (kWh)	2	2	4	10
Optimised DER Configuration - Electrified Transport Only				
PV (kW)	4	4	6	10
ES (kWh)	2	2	4	10
Optimised DER Configuration - Electrified Building Only				
PV (kW)	0	4	6	10
ES (kWh)	2	2	4	10
Optimised DER Configuration - Electrified Building and Transport				
PV (kW)	6	6	8	10
ES (kWh)	0	2	6	10

Source: Energeia modelling

The above results for NSW are comparable to trends in the other states. The key drivers of changes in the optimal size of rooftop solar PV and/or BTM storage are technology prices and wholesale market prices. Network LRMCs are kept constant over the period.

The sizing of rooftop solar and BTM storage under the ISP Step Change scenarios was based on the average capacity reported by consultant reports that fed into the ISP.

4.1.4 Optimised Load Profiles

A visualisation of our modelling results for the average summer and winter days in 2030 are reported below for selected consumer segments in NSW.

The ISP Step Change scenario reflects a 10 kWh BTM battery and 7 kW of rooftop PV, while the Consumer High DER scenario reflects 6 kW of rooftop solar PV in both scenarios and a 2 kWh average BTM battery in both the no electrification scenario (left) and the fully electrified scenario (right).

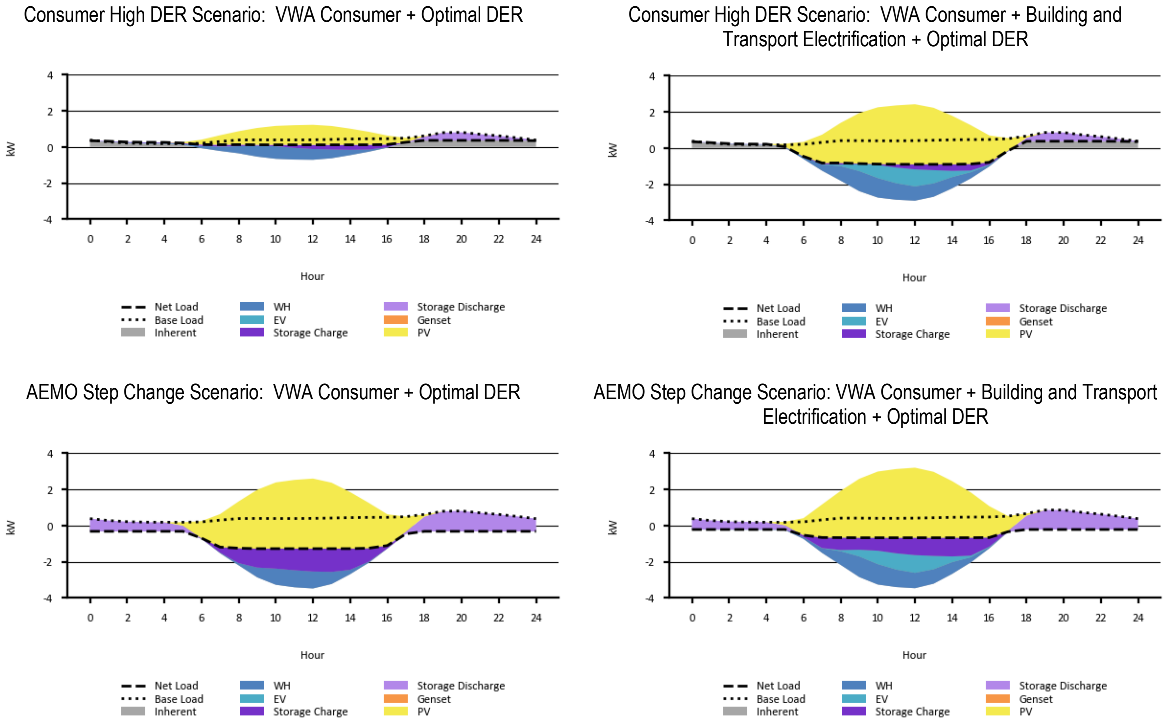
4.1.4.1 Summer Average Day

The figure below compares consumers without (left) and with (right) vehicle and building electrification across the Consumer High DER (top) and ISP Step Change (bottom) scenarios in NSW in 2030 to illustrate key differences between the modelling.

Consumers in the Consumer High DER scenarios (top) are able to flatten their grid demand (baseload) to maximise their load factor except during the periods of maximum solar PV exports.[43] The larger battery in the AEMO Step Change scenarios (bottom) is able to virtually eliminate positive grid demand (net load) on average during the summer months, instead, solar PV exports become the main grid service in this scenario for this consumer segment.

[43] Energeia's modelling found that PV export capacity greater than peak demand capacity was uneconomic and capped them in the CBA.

Figure 13 – Average Summer Residential Load Profiles by Scenario (NSW, 2030)



Source: Energeia modelling

4.1.4.2 Average Winter Day

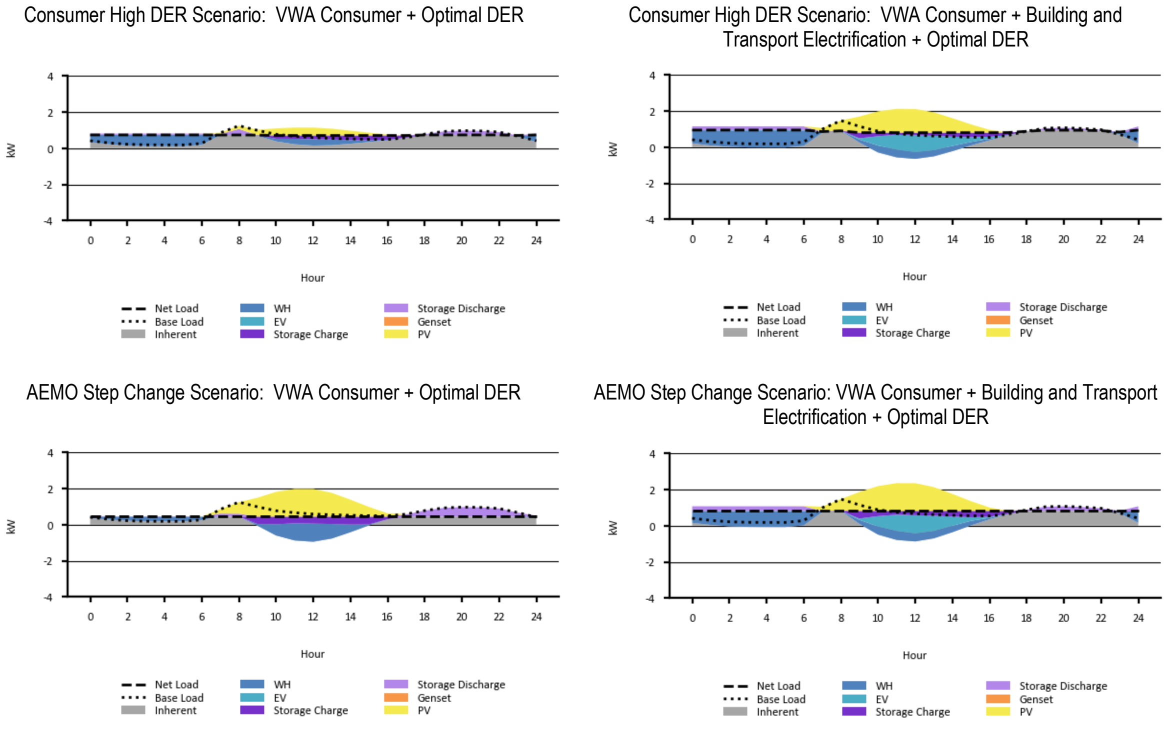
The figure below again compares consumers without (left) and with (right) vehicle and building electrification across the Consumer High DER (top) and ISP Step Change (bottom) scenarios in NSW in 2030 to illustrate key differences between the modelling.

The overall load shape changes in the winter months due to less solar PV generation, and the shifting of space conditioning load from the afternoon to the morning hours.

During the winter months, the modelling shows consumers in the Consumer High DER scenarios (top) are again able to flatten their grid demand to maximise their load factors, except during the periods of maximum solar PV exports.[44] The larger battery in the AEMO Step Change scenarios (bottom) is almost able to deliver a completely flat load profile on average, with demand dipping slightly during the periods of high solar PV production.

[44] Energeia's modelling found that PV export capacity greater than peak demand capacity was uneconomic, and capped them in the CBA.

Figure 14 – Average Winter Residential Load Profiles by Scenario (NSW, 2030)



Source: Energeia modelling

It is important to note that the above customer segments change each year in terms of their solar PV and storage configuration and are weighted in the overall state grid peak demand and consumption based on the level of vehicle and building electrification assumed under each scenario.

4.1.5 Optimised Rooftop Solar PV

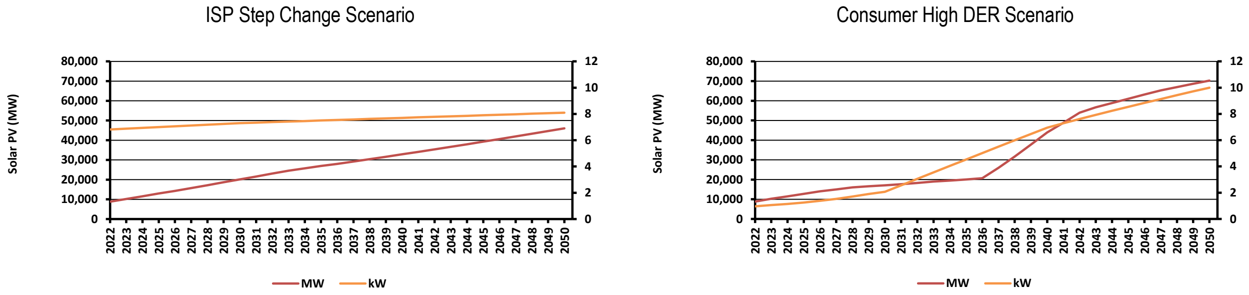
The results of Energeia's modelling of average and total residential rooftop solar PV capacity in the Consumer High DER scenario are reported in Figure 15 on the following page at the NEM level alongside the ISP Step Change[45] scenario values.

The Consumer High DER scenario's average rooftop solar PV values are based on the customer cost optimisation model, with smoothing used in between periods. The total capacity value reflects the change in average sizing and the assumed level of electrification as reported in Figure 12 and Table 4 respectively.

The optimised solar PV size under the Consumer High DER scenario is much lower than the level assumed in the ISP Step Change scenario until 2038. In terms of total rooftop solar PV deployed, the ISP Step Change scenario sees about half the level of the Consumer High DER scenario.

[45] The ISP does not report the average value. Values were therefore taken from consultant's reports incorporated into the ISP.

Figure 15 – Residential Rooftop Solar PV Average kW and Total MW by Scenario (NEM)



Source: AEMO, Energeia

4.1.6 Optimised BTM Storage

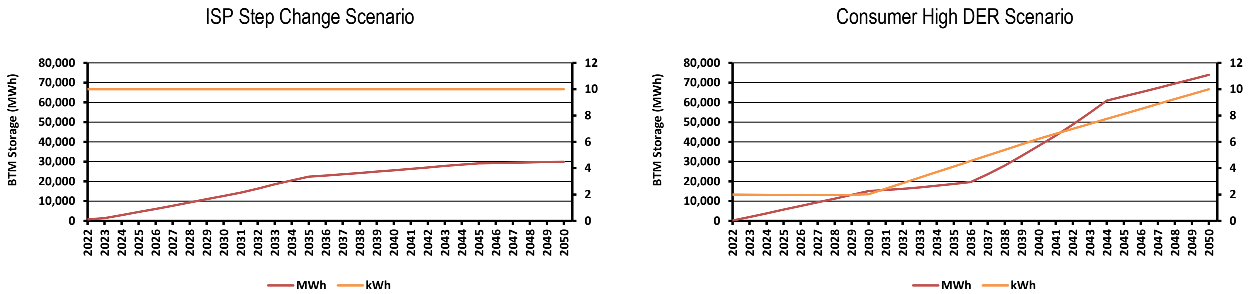
The results of Energeia's modelling of average and total residential BTM storage capacity in the Consumer High DER scenario are reported in the figure below at the NEM level alongside the ISP Step Change[46] scenario values.

As is the case with rooftop solar PV, the Consumer High DER scenario's average BTM storage values per consumer are based on the customer cost optimisation model, with smoothing used in between modelled periods. The total capacity value reflects the change in average sizing and the assumed level of adoption.

The optimised BTM storage size per consumer under the Consumer High DER scenario is again much lower than the level assumed in the ISP Step Change scenario until the 2048-2050 period. Energeia sees the difference in outcomes due to the projection of the current, early adopter market in the ISP Step Change scenario, compared to the optimised sizing assumed in the Consumer High DER scenario.

Despite the lower average sizing of BTM storage in the Consumer High DER scenario, the overall level of BTM storage rises above the ISP Step Change scenario from around 2038 onwards, reaching over two times higher by 2050. A key driver of the ramp up in total capacity from 2037 under the Consumer High DER scenario is the effect of battery replacements[47] occurring in the presence of significantly lower prices.

Figure 16 – Residential BTM Storage Average kWh and Total MWh by Scenario (NEM)



Source: AEMO, Energeia

4.1.7 Consumption

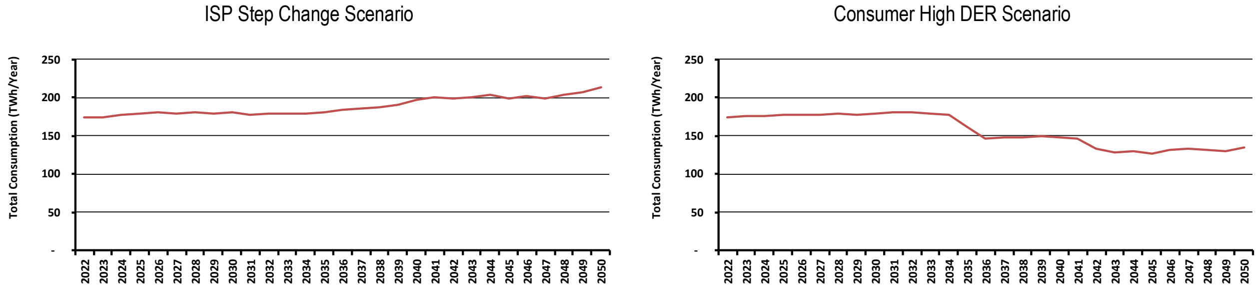
Energeia modelled aggregated grid consumption and peak demand (see next page) under the Consumer High DER scenario the same way as we did for rooftop PV, BTM storage and grid peak demand, by weighting each of the consumer segments over time. The ISP Step Change scenario consumption values reported in the figure below are higher than those reported in the ISP due to the higher levels of building electrification assumed.

[46] The ISP does not report the average value. Values were therefore taken from consultant's reports incorporated into the ISP.

[47] A 15 year average lifetime is assumed for BTM battery storage, after which time the batteries are replaced at the optimal size.

The results of our modelling of total annual grid consumption across the NEM by scenario to 2050 is reported in the figure below. Annual NEM consumption under the Consumer High DER scenario declines in steps from 2036 with the exit of inflexible coal generators, which reduces the curtailment of the higher rooftop solar PV capacity in this scenario. Under the ISP Step Change scenario, significantly lower levels of rooftop solar PV result in an overall rise in system level consumption over the period to 2050.

Figure 17 – Annual Consumption by Scenario (NEM)



Source: AEMO, Energeia

4.1.8 Demand

Peak demand has been the key driver of generation capacity and network investment since the beginning of the industry. Today, the rising level of solar PV generation is leading to rapidly falling minimum demand, which is in turn driving investment in different types of generation capacity, and increasingly, in distribution network capacity. Energeia modelled both drivers, and the results of our modelling are reported below.

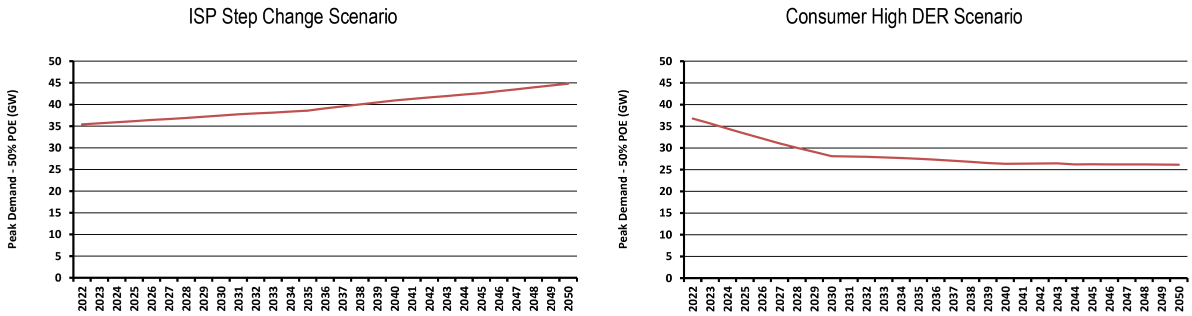
4.1.8.1 Maximum

The results of our modelling of total coincident peak demand across the NEM by scenario to 2050 is reported in the figure below.

Energeia's modelling shows annual NEM level peak demand under the Consumer High DER scenario rapidly declines over the next ten years driven by the impact of BTM storage. Even though storage during this time is 2-3 kWh on average for residential consumers, for example, this is sufficient to reduce peak demand assuming it can be orchestrated. The rate of peak demand reduction starts to taper from 2031 onwards as the rate of storage adoption declines and the rate of demand increasing electrification rises.

Under the ISP Step Change Scenario, NEM level demand rises gradually to 2035 and then more quickly to 2050. As is the case with our modelling of total NEM consumption, our modelling of total NEM peak demand is higher than the level reported in the ISP due to the impact of higher building electrification assumed in our modelling. This leads to higher near-term growth than the ISP Step Change scenario, but is comparable to the overall trajectory and level by 2040.

Figure 18 – 50% POE Peak Demand by Scenario (NEM)



Source: AEMO, Energeia

4.2 Generation

Analysing the costs and benefits of integration of high levels of DER into the generation system is a key objective of this study. Of particular interest to stakeholders as reported during our engagement workshops is understanding the potential role of DER orchestration in minimising energy prices, generation costs and investment costs, especially those relating to high levels of solar PV generation.

Energeia modelled the impact of DER on the NEM by configuring its wholesale market modelling software, Wholesale Simulator or wSim, using the key outputs from the Customer Optimisation modelling, including annual hourly grid demand profiles, and controllable water heating, vehicle charging, BTM storage and rooftop PV resource levels. DER was orchestrated to minimise system costs.

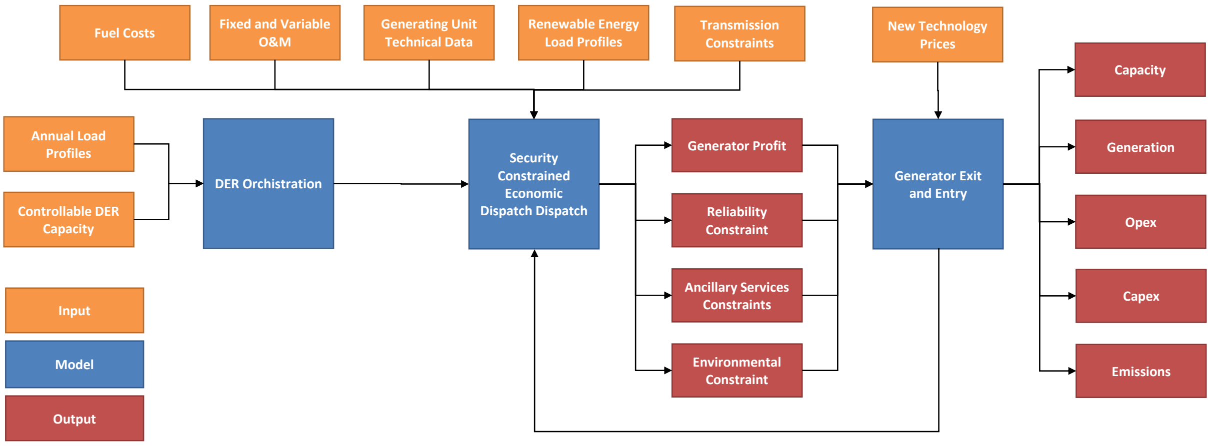
4.2.1 Methodology

Energeia's NEM modelling methodology is summarised in the diagram below, which shows the key components and processing steps used.

Annual operational load and controllable DER is supplied for this exercise from the customer optimisation and aggregation model, which was explained in Section 4.1. The DER orchestration model then shapes the DER to minimise generation costs, mainly by shifting load away from peak periods and into minimum demand periods, and by curtailing solar PV when it leads to system stability issues.[48]

The Security Constrained[49] Economic Dispatch (SCED) of resources and associated clearing prices are then determined each year given the relative costs[50] of each resource type. The resulting generator profits and prices are used to determine generator exit and entry, and the SCED step is repeated until there is no more economic entry or exit, and the solution meets all specified reliability, ancillary services and environmental constraints[51].

Figure 19 – Wholesale Market Modelling Diagram



Source: Energeia

No study in Australia to date has examined the impact of high levels of DER on Australia's wholesale energy market. As this is the first time Energeia undertook such a study, we had to adapt our tools for the job, developing a number of new methodologies, inputs and assumptions related to how high levels of DER operating as virtual power plants using orchestration would operate, as well as how existing resources would respond.

[48] The modelling assumes perfect information, which is a limitation. In practice, we see 85% of perfect foresight is achievable.

[49] Security constrained means that dispatch is subject to transmission and operational constraints.

[50] As explained in the key assumptions section below, strategic bidding was not used for this economically focused study.

[51] Least cost solutions to environmental, ancillary services and reliability constraints are identified using the SCED process.

4.2.2 Key Inputs and Assumptions

The following sections report on the key inputs and assumptions Energeia developed as part of the series of updates to our wholesale market modelling software needed to model high levels of DER.

4.2.2.1 Managing Excess Generation

The Consumer High DER scenario sees rooftop solar PV rise from around 10 GW today to 36 GW by 2030 and around 127 GW by 2050. Energeia managed excess generation on a least cost basis. This required developing accurate estimates of the cost of reducing output. DER orchestration was aimed at minimising costs, which typically led to it shifting load to minimum demand periods, as the least cost periods of the day.

4.2.2.2 Flexibility Costs

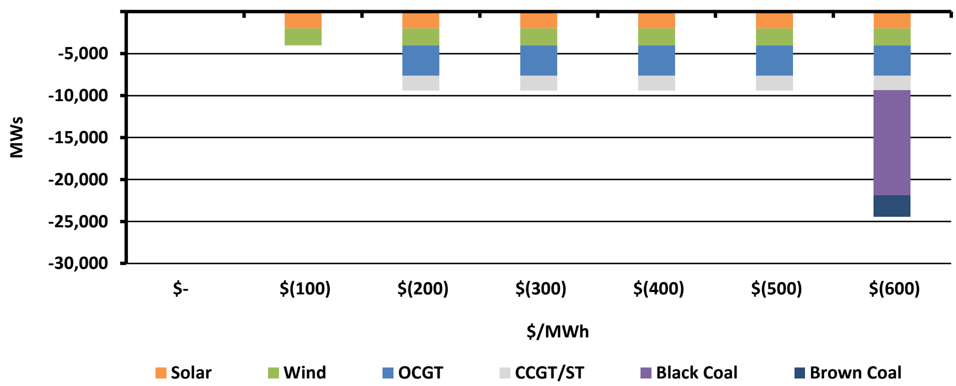
The NEM dispatches units every 5 minutes based on their bids and system constraints. Resources are allowed to bid negative prices to avoid being turned off, and negative prices are increasingly setting the system price as rooftop solar PV generation eats away at minimum demand levels.

There are two main drivers of negative prices.

- **Renewable Energy Certificate Revenues -** Renewable Energy Certificates (RECs) are earned by utility scale renewable energy generators for every MWh generated. A utility scale solar PV station will therefore rationally bid up to the value of the REC before shutting down. For wind generators, there is a small operational cost to generate electricity, so their minimum price is the value of the REC less the operational cost. Wind should therefore, in theory, shutdown before utility scale solar PV. Rooftop solar PV does not earn a REC and is therefore the least cost renewable energy resource to shut down, at least until 2030, when the REC system ends, and utility and rooftop solar PV will be on an equal footing.
- **Thermal Unit Shutdown and Restart Costs –** Thermal units incur costs to shut down and restart, mainly from the cost of the fuel required to bring them back online, but also the additional hours of labour required to operate the process. Restart costs are therefore higher for longer duration outages, when the plant has lost all its thermal mass, and more maintenance is required prior to restarting. There is also the higher wear and tear on the units themselves, which can reduce lifetimes. Steam turbine technology used by coal plants is higher cost to cycle than open cycle, aeroderivative technology favoured by gas plants, with combined cycle technology falling in between.

The figure below displays Energeia's estimated flexibility supply curve in 2022, showing the price needed to reduce supply. Energeia used these estimates to develop negative bids for these units which priced reductions in generation just below the price of the next most expensive technology. For example, solar PV generation bid in at wind's negative price less one dollar, to minimise the impact of the negative price while still dislocating wind generation when needed.

Figure 20 – Flexibility Supply Cost Curve



Source: Energeia research, AEMO

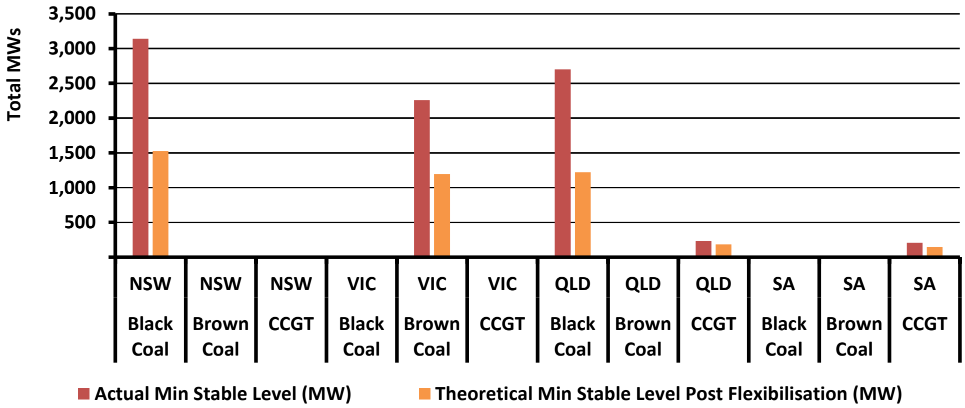
Energeia notes that the flexibility supply cost curve is dynamic, as the amount of wind and solar PV changes on a second-by-second basis, and thermal plants go offline for periodic maintenance, and exit or enter the market every year. Generally speaking, flexibility costs will fall over time as more and more low cost solar, wind and lithium and other types of storage resources come online and the more expensive thermal plant retires.

A key insight from our work on flexibility supply costs is that, operating efficiently, NEM prices should never fall below the value of RECs (less one dollar), as this should reduce all renewable energy generation, including rooftop solar PV. By shielding rooftop solar PV from NEM prices signals, Australia has created a situation whereby higher cost thermal units are being turned off instead. Another key insight is that once the REC advantage of utility scale solar PV plants is removed in 2030, negative prices are likely to decrease, as they will no longer be needed to curtail solar PV generation. Batteries and loads that enter to target negative prices driven by poor integration of DER and REC-driven bidding may be caught off-guard by these dynamics.

4.2.2.3 Minimum Stable Generation

Energeia's estimate of minimum stable generation by state and generating technology is reported in the figure below, alongside estimates of the potential to enable units to run at lower levels. Energeia assumed the minimum stable generation levels reported below, transitioning to the post flexibilisation levels by 2030. Minimum stable generation levels govern the level below which units will start bidding their shutdown costs, and the level of demand when negative prices are likely to emerge in order to backdown lower cost options like wind and solar.

Figure 21 – *Flexibility Supply Cost Curve*



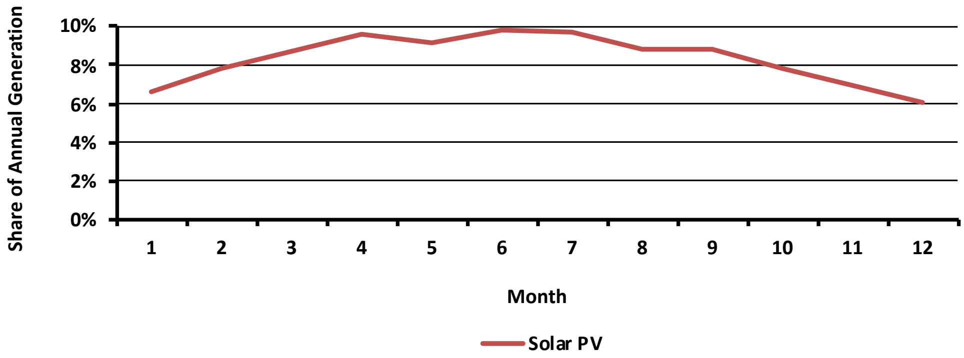
Source: Energeia Research, AEMO

4.2.2.4 Unit Maintenance

Thermal generators must shutdown periodically to undergo annual maintenance, which is typically scheduled to avoid missing the highest priced periods in the year, and to also ensure system reliability. Rising solar PV generation, and the resulting reduction in minimum net demand for thermal generation, is expected to change generator maintenance behaviour, especially as additional lithium and other forms of storage come online capable of meeting peak demand.

As part of this study and our quest to analyse the system's capability to become more flexible, Energeia reviewed the potential to schedule maintenance to avoid times of highest solar PV energy generation. The figure below shows the monthly output of solar PV as a percentage of annual generation. It shows that solar PV generation increases by almost two thirds in the summer months from October to January compared to the winter months of June and July.

Figure 22 – Monthly Solar PV Generation as Percentage of Total Annual



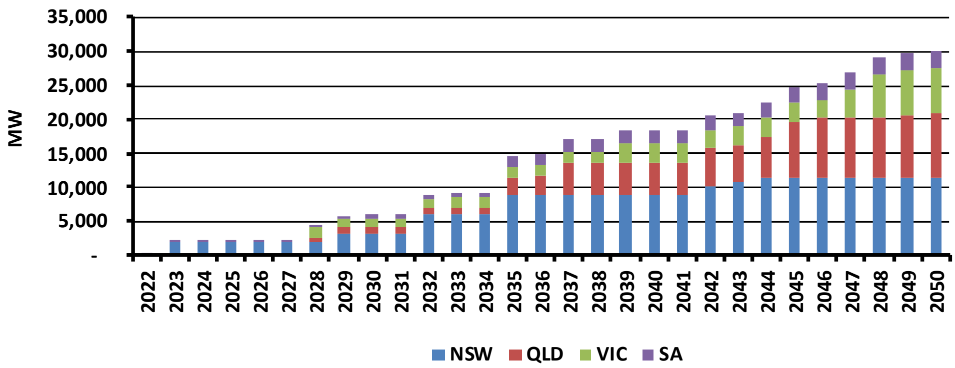
Source: Energeia research, AEMO

Although the current approach favours maintenance outside of the summer period, when peak demand is highest, our analysis suggests that over time thermal unit maintenance is likely to shift to summer to better avoid lower and negative prices. This will only be possible assuming storage and other dispatchable capacity is available to meet peak demand in the summer. Energeia's analysis suggests that significant levels of storage are also likely to lead to a significant improvement in system load factor and reduction in the summer peak.

4.2.2.5 Thermal Unit Retirements

Longer-term, the planned retirements of thermal units will reduce the level of minimum demand needed to operate thermal plants reliably. The figure below reports on the latest retirement schedule published by AEMO as part of the ISP. Energeia's modelling assumed this schedule, except in cases where market prices lead to a specific generating exiting the market earlier, provided it could be done without jeopardising reliability.

Figure 23 – Planned Thermal Capacity Retirements by State



Source: Energeia research, AEMO

4.2.2.6 Bidding Behaviour

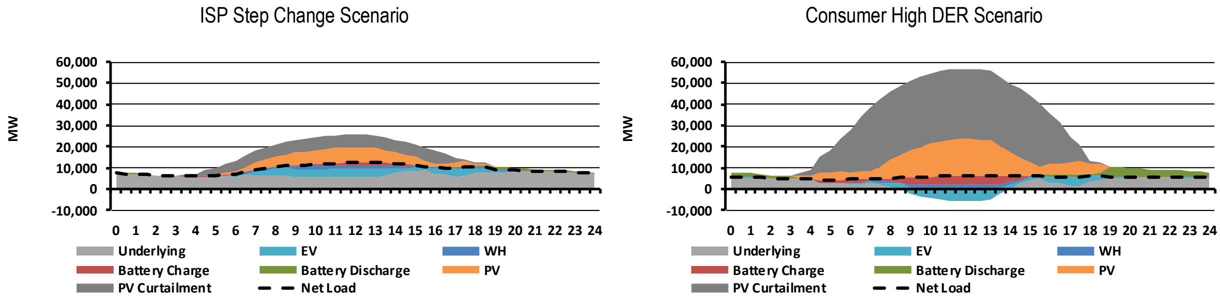
Energeia's wholesale market model typically operates using strategic bidding assumptions, as these generate prices that are closest to actual prices seen in the NEM. Strategic bidding takes account of generators with a portfolio of units, who typically manage their bids across this portfolio to maximise profits across the portfolio, and not for a given generating unit.

For this study, which is focused on the economics of high levels of DER, Energeia has assumed economic bidding behaviour, which assumes generators bid in their units at their Long-Run-Marginal-Cost (LRMC), and only exit where they cannot recoup their annual fixed Operations and Maintenance (O&M) costs. New generating units, however, only enter where they are expected to earn the required rate of return, in addition to their fixed and variable O&M costs.

4.2.3 Virtual Power Plants

The figure below reports on the results of our VPP optimisation modelling for NSW in 2050 across the summer months by scenario. Significantly less PV and BTM storage adoption under the ISP Step Change scenario leads to less curtailment in percentage terms over the average summer day compared to the Customer High DER scenario.

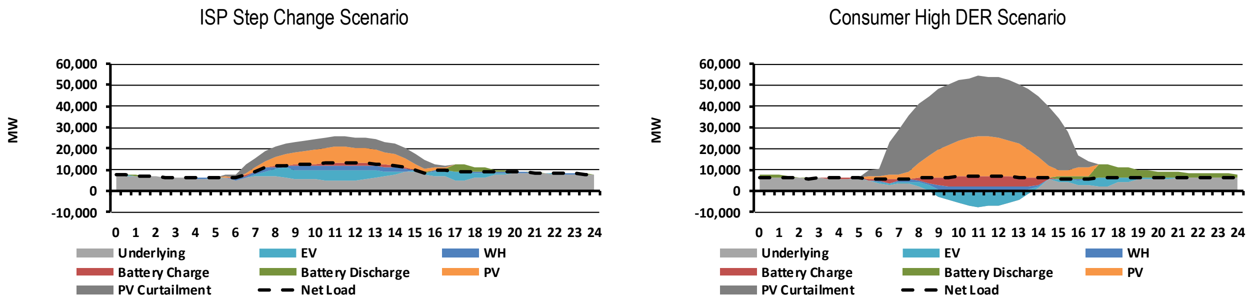
Figure 24 – Average Summer Day Virtual Power Plant Profiles in NSW in 2050 by Scenario



Source: Energeia modelling

During the winter months, the level of curtailment seen in the ISP Step Change scenario is also less than in the High DER scenario. Overall, around 70% of rooftop solar PV is curtailed under the Consumer High DER scenario in 2050, compared to around 50% for the ISP Step Change Scenario.

Figure 25 – Average Winter Day Virtual Power Plant Profiles in NSW in 2030 by Scenario



Source: Energeia modelling

It is important to note that the above optimisation is based on the relative cost of curtailing other resources, which was explained in Section 4.2.2.2. Curtailment of Rooftop PV exports to the grid is mainly expected to occur in response to negative prices, however, it could also be triggered by the market operator to maintain system security.

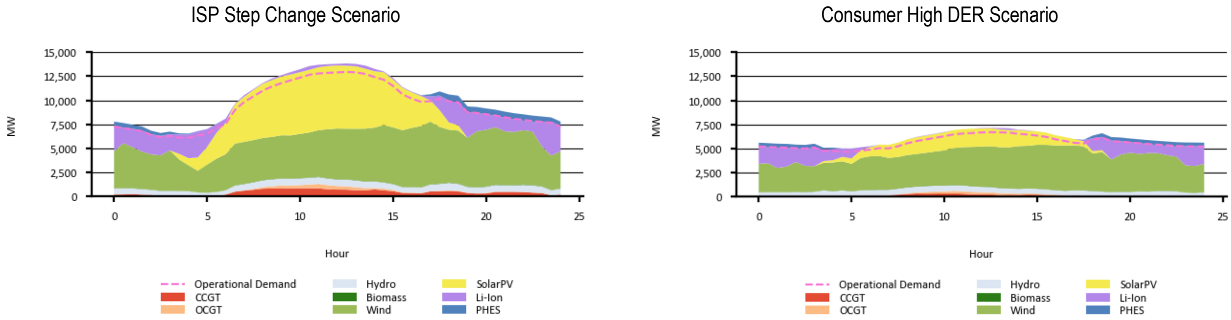
4.2.4 Daily Generation Profiles

The figure on the following page reports on the results of Energeia's modelling of hourly average summer generation in NSW in 2050 to provide an example of the key differences between the ISP Step Change and Consumer High DER scenarios.

The figure shows that overall hourly operational demand load shape in the ISP Step Change scenario to be significantly higher than for the Consumer High DER scenario, mainly due to significantly more rooftop solar PV in the latter scenario in 2050. BTM storage is used by VPPs to shift excess rooftop solar PV to other periods, therefore reducing average hourly demand compared to the ISP Step Change scenario.

Energeia notes a significant increase in demand during solar PV output hours compared to today's system load shape, which is due to the impact of VPPs shifting EV and electric water heating load into the middle of the day.

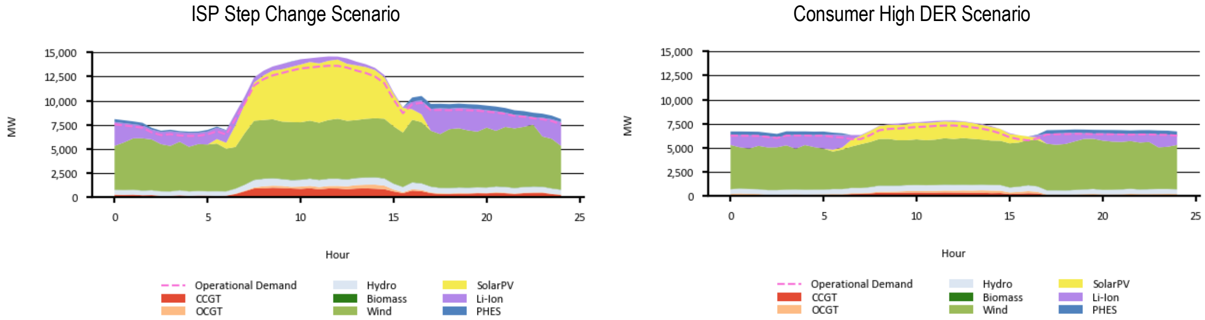
Figure 26 – Illustrative Average Summer Day Generation Profile in NSW in 2050



Source: Energeia modelling

The results of Energeia's modelling of hourly average generation in NSW during the winter months is shown in the figures below. Again, the key difference between the scenarios is the overall level of demand, with greater consumption in the ISP scenario resulting in higher utility-scale solar, as well as higher levels of fossil fuel generation, compared to the Consumer High DER scenario.

Figure 27 – Illustrative Average Winter Day Generation Profile in NSW in 2050



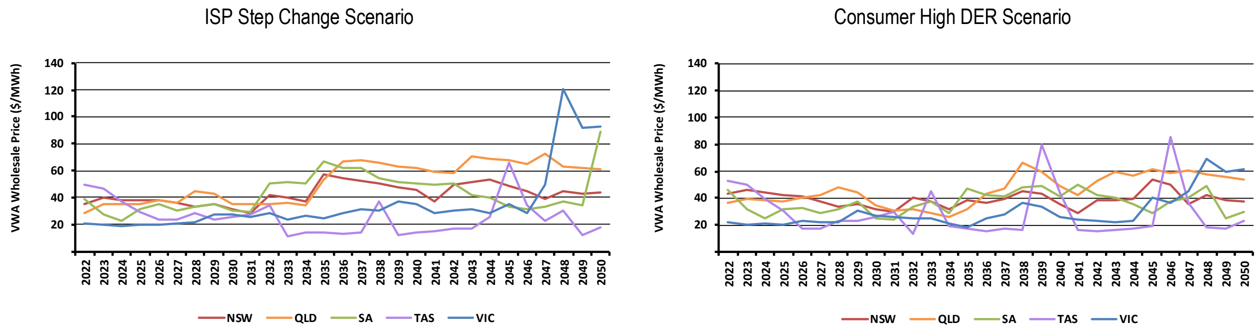
Source: Energeia modelling

The above worked example for NSW is typical of the generation profiles and dynamics seen in the other markets.

4.2.5 Wholesale Pricing

Energeia's modelling of volume weighted average wholesale market energy prices by state and scenario are shown in the figure below to 2050. The modelling shows energy prices under the Consumer High DER scenario remain below levels seen in the ISP Step Change scenario, particularly in NSW, VIC and SA post 2028.

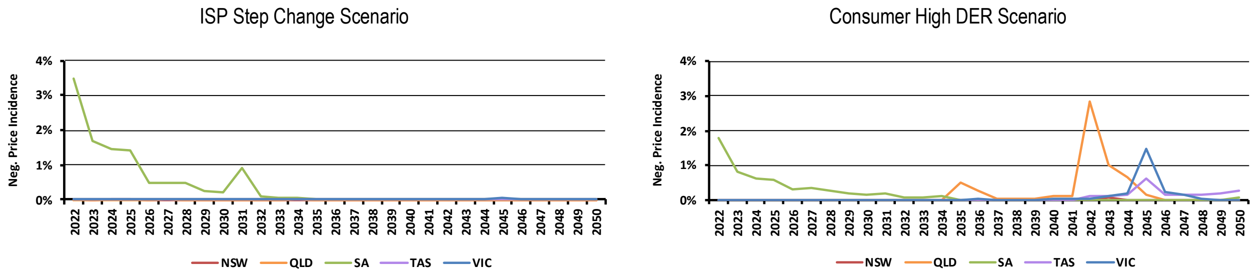
Figure 28 – Volume Weighted Average Energy Pricing



Source: Energeia modelling

The figure below reports on the incidence of negative pricing periods by state and scenario. Our modelling shows similar, falling levels of negatively priced periods across both scenarios until the 2040's, when the levels occasionally spike and begin to rise in the Consumer High DER scenario for Queensland, Tasmania, and Victoria.

Figure 29 – Incidence of Negative Price Periods

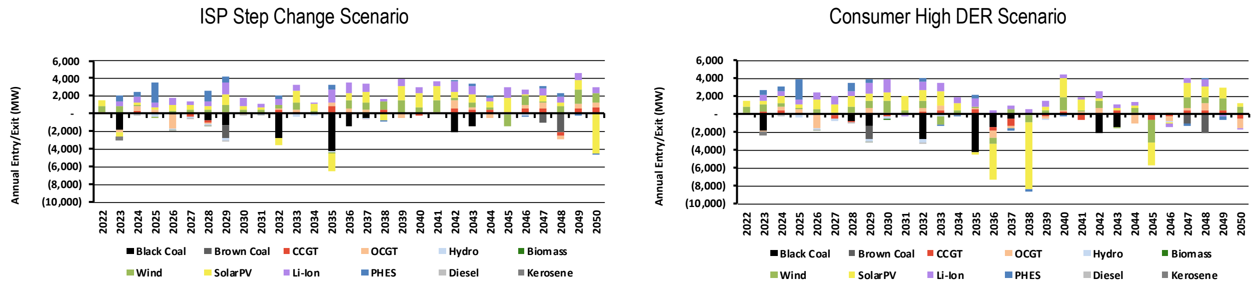


Source: Energeia modelling

4.2.6 Entry and Exit

Energeia's modelling of annual wholesale market entry and exit are shown in the figures below. Overall system peak demand is lower in the Consumer High DER scenario, leading to less overall net entry, split relatively evenly among technologies.

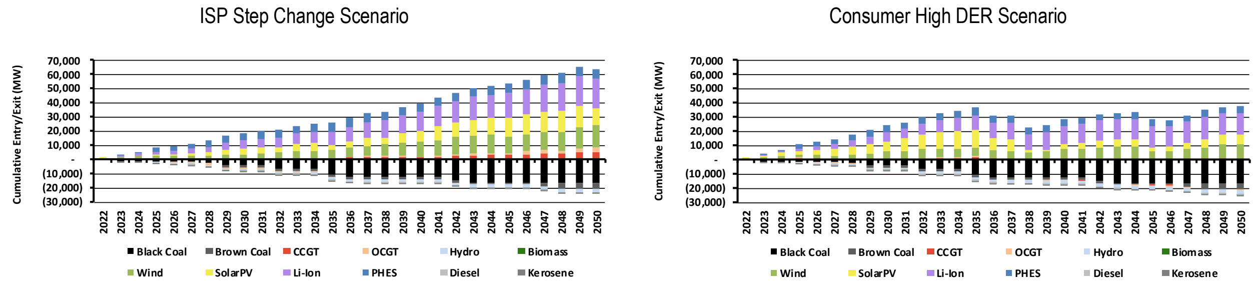
Figure 30 – Annual Generation Entry/Exit to 2050



Source: Energeia modelling

The below figure shows a cumulative view of entry and exit, illustrating the significant difference in overall entry by 2050.

Figure 31 – Cumulative Generation Entry/Exit to 2050



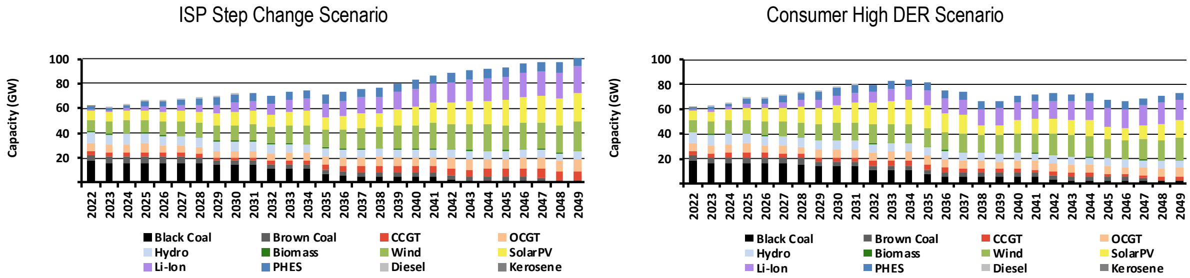
Source: Energeia modelling

4.2.7 Capacity

Flattening of state level demand mainly due to VPP operation leads to exiting of inflexible generation including black and brown coal, and some flexible generation including diesel and kerosene units, unable to earn sufficient revenues to remain in the market, in favour of technologies like lithium battery storage, which are able to profit from peak to off-peak differentials and not just peak prices.

The figure below reports on the results of Energeia's modelling of total utility scale generation in the NEM to 2050 by scenario. The key differences between the two scenarios are the lower level of wind, solar, CCGT, OCGT and lithium capacity in the Consumer High DER scenario, due to higher rooftop solar PV and BTM storage capacity in the latter scenario.

Figure 32 – NEM Capacity by Technology and Scenario to 2035

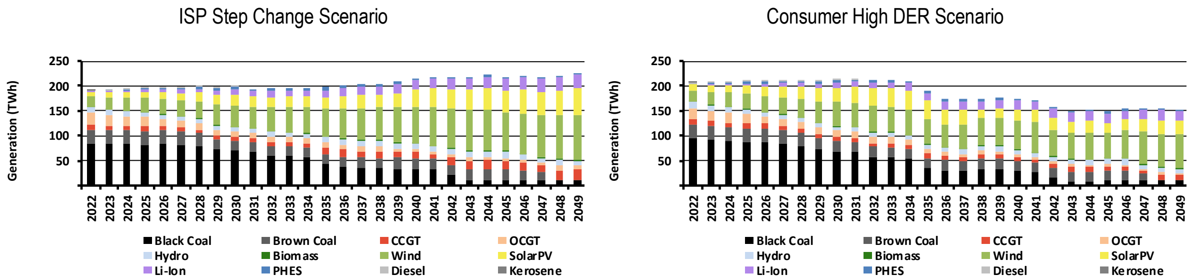


Source: Energeia Modelling

4.2.8 Generation

The figure below reports on NEM-wide generation by resource by scenario to 2050. As is the case with the capacity modelling, there is little difference between the two scenarios up to around 2035. However, after this time, generation begins to decline in the Consumer High DER scenario due to the impact higher rooftop solar PV and falling rates of curtailment. Another key difference between the scenarios is the level of solar and wind generation, which is around twice as high in the ISP Step Change scenario.

Figure 33 – NEM Generation by Technology and Scenario to 2050



Source: Energeia Modelling

Energeia notes that VPP managed DER, mainly BTM storage, is used to provide key ancillary services to the wholesale market including intertia and ramping reserves (to manage sudden changes in renewable generation, e.g. due to cloud cover or wind gusts) under both scenarios.

ENERGEIA

5 Key Barriers and Drives to the Optimal Future State

Based on our learnings from Phase 1 and 2 of this study, consultation with key stakeholders, and our experience working in Australia and the US to optimally integrate Distributed Energy Resources (DER) into the power system and grid, Energeia has identified a range of key barriers to the efficient investment, operation and integration of optimal levels of DER, which are detailed in this section.

We have grouped the key barriers into the three themes of:

- **Leveling the playing field** – Inaccurate pricing and benefit assessment mechanisms that disadvantage DER, leading to under-investment in DER relative to optimal economic levels.
- **Distributed energy resource enablement** – Planning methods and operational systems that, when absent, act as barriers to optimal investment and operation of DER, and
- **Industry incentives** – Regulatory methods that disadvantage DER but could become strong drivers of optimal DER investment and operation if reformed.

In Energeia's view, the degree to which Australian consumers are able to realise the net benefits identified in Section 7 will depend on the timing and degree to which these key barriers are addressed.

5.1 Level Playing Field

Energeia's customer, network and generation modelling has shown significant net benefits accruing from optimised levels of DER investment and operation across the industry value chain. Our research, analysis and experience has identified the following key barriers to achieving the Consumer High DER scenario outcomes:

- Tariffs that do not reflect Long-Run-Marginal-Cost (LRMC)
- Tariffs that do not reflect network cost drivers, e.g. export prices
- Tariffs that do not reflect DER system economics
- Tariff assignment policies that do not require cost reflective tariffs for DER
- Investment optimisation methodologies that do not reflect offsetting DER revenues, e.g. RIT-D

The above list focuses on the key barriers, however, there are a wide range of technical issues that will also have to be addressed to implement them effectively, which are beyond the scope of this report.

5.1.1 Long-Run-Marginal-Cost

Energeia's analysis in Section 4.1.2.2 identified that most LRMC calculations used to set network prices only appear to reflect a small fraction of network LRMC. This results in lower, uneconomic price signals for peak demand managing investments, and therefore lower, uneconomic levels of DER investment. Higher LRMCs will result in lower residual costs to be recovered, reducing volumetric prices, and encouraging greater electrification.

Establishing LRMCs that reflect 100% of the avoidable investment over the long-run[52] in discounted value terms will support efficient pricing signals capable of soliciting efficient levels and operation of DER.

5.1.2 Network Pricing Signals[53]

Achieving the levels of DER seen in the Consumer High DER Scenario requires charging consumers for the level of network demand (i.e. capacity) they use at the correct (LRMC) price. The cost of different portions of the network should be charged at different times where Coincident Maximum Demand (CMD) occurs at different times. If the timing of CMD changes over time, e.g. due to the impact of rooftop solar PV, then the timing of the price signal should change as well. As the exact timing of CMD is unknown, it cannot be set in advance without a

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[52] For example, a 50-60 year period

[53] Energeia notes that we have not listed real-time wholesale market pricing signals, as these are already existing.

loss of efficiency due to forecasting error leading to incorrectly set periods. Price signals for DER-enabled consumers should therefore be dynamic for maximum efficiency.

Dynamic price signals set at the true LRMC and set to coordinate peak demand reductions across the network's connected assets will solicit efficient levels and operation of DER to manage demand as required by the Rules.

5.1.3 Export Pricing Signals

Energeia's analysis of the cost of hosting high levels of solar PV has found that solar PV investment drives the need for investment in phase balancing, protection and voltage scheme modifications, constraint management capabilities (e.g. Dynamic Operating Envelopes [DOEs]), orchestration capabilities (e.g. Distributed Energy Resource Management Systems [DERMS]) and curtailment in order to avoid relatively expensive thermal capacity increasing solutions including larger assets sized.

Key barriers to efficient DER investment include the following.

5.1.3.1 Pricing Structure

The AEMC's recent rule change[54] concerning DER accessibility has highlighted the need for networks to develop tariffs for export services as part of serving consumers at the lowest possible cost.

Given the nature of rooftop solar PV costs, which increase with higher levels of rooftop solar PV generation, an inclining block, time-based (i.e. tiers vary by time) structure may be most appropriate until dynamically generated, network ancillary services-like prices are able to be established on a nodal basis.

Each block of peak period consumption or power could be set based on the expected average level of solar PV generation that would trigger the additional investment. For example, the first tranche may allow up to 3-5 kW of solar PV during the peak congestion period without incurring a charge or incurring a nominal charge for phase balancing. Above this level, e.g. 5-7 kW, would incur costs for managing protection and voltage issues, and above 8 kW would incur expected asset augmentation costs.

5.1.3.2 Solar PV Generation Certificates

A key issue to be considered in the setting of tiers is how to deal with consumers unable to install rooftop solar PV buying from their neighbour instead. Under the above quota-like system, DER generators investing over the allowed level would see higher export costs, which would be passed on to their DER buying neighbour. A system of solar PV generation 'rights' in the form certificates could be used to allow DER generators and consumers in this scenario avoid incurring the higher costs that would otherwise occur.

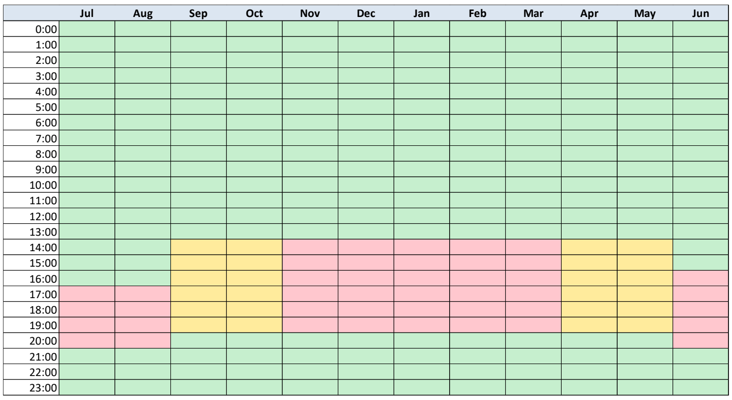
5.1.3.3 Pricing Periods

The Rules and economic efficiency both require that the marginal costs identified above need to be charged during the periods of congestion, which Figure *36* shows will be between 10am and 2pm, during the months of October to January. Ideally these will be determined and signalled to solar PV generators on a forward and dynamic basis so that DER management systems can respond effectively and efficiently.

In the near-term, establishing more accurate solar PV congestion periods is essential to minimising the risk of uneconomic over investment in solar PV and under investment in solar PV cost-mitigating DER. Current DNSP congestion periods, illustrated by Ausgrid's example in the figure below, will need to be modified to avoid continuing to send the signal that solar PV generation does not drive additional investment costs.

[54] AEMC (2021), National Electricity Amendment (Access, Pricing And Incentive Arrangements For Distributed Energy Resources) Rule 2021, https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf

Figure 34 – Current Solar PV Congestion Signalling (Ausgrid)



Source: Ausgrid, Energeia

Energeia's analysis of DNSP substations has identified that using current minimum demand levels leads to inaccurate solar PV congestion period determination; forward looking solar PV congestion periods are therefore needed. The figure below shows Ausgrid's current minimum demand levels for each period as the percentage of zone substations being within 10% of the overall network's minimum demand for the year.

Figure 35 – Current Solar PV Congestion Signalling (Ausgrid)

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
0:00	7.91%	9.04%	18.08%	19.21%	16.38%	11.86%	5.08%	5.65%	11.30%	25.42%	11.86%	8.47%
1:00	17.51%	18.08%	36.72%	37.85%	36.72%	32.20%	16.38%	21.47%	29.38%	48.02%	33.33%	18.08%
2:00	31.07%	33.90%	59.89%	57.63%	58.19%	58.76%	47.46%	45.20%	53.11%	72.88%	55.93%	37.85%
3:00	57.06%	61.02%	76.84%	72.88%	78.53%	76.84%	70.06%	68.93%	74.58%	83.05%	73.45%	59.89%
4:00	65.54%	69.49%	83.05%	82.49%	80.23%	83.05%	77.97%	71.19%	76.27%	84.18%	79.66%	67.80%
5:00	54.24%	61.58%	81.36%	75.71%	74.58%	81.36%	74.01%	64.97%	71.75%	84.18%	72.32%	58.19%
6:00	11.86%	12.43%	78.53%	49.15%	45.20%	72.88%	59.89%	31.07%	36.72%	75.14%	32.20%	36.16%
7:00	1.69%	2.26%	67.23%	8.47%	9.60%	49.15%	28.81%	3.39%	5.08%	59.32%	3.95%	23.73%
8:00	0.56%	2.82%	33.90%	3.95%	6.78%	20.34%	9.60%	0.56%	3.95%	32.77%	1.13%	19.21%
9:00	1.13%	4.52%	20.90%	12.43%	12.43%	13.56%	6.21%	3.95%	6.21%	28.25%	5.65%	19.77%
10:00	3.39%	11.86%	20.34%	19.21%	19.77%	12.99%	6.78%	7.34%	10.17%	29.94%	12.99%	4.52%
11:00	7.91%	19.21%	24.86%	23.73%	20.90%	14.69%	7.34%	10.73%	16.38%	32.20%	18.08%	9.60%
12:00	11.30%	21.47%	28.25%	27.68%	22.03%	14.69%	6.78%	12.43%	15.82%	33.33%	19.77%	13.56%
13:00	11.86%	23.16%	29.38%	27.68%	23.16%	16.38%	7.34%	11.86%	16.95%	34.46%	19.77%	14.12%
14:00	12.99%	23.16%	27.68%	28.81%	22.60%	18.64%	8.47%	11.86%	18.64%	37.29%	18.64%	14.69%
15:00	11.30%	20.34%	27.12%	28.25%	22.03%	16.95%	6.21%	11.86%	18.08%	35.03%	16.38%	12.43%
16:00	3.95%	12.43%	22.60%	25.42%	16.95%	10.17%	4.52%	5.08%	14.12%	22.03%	6.21%	4.52%
17:00	2.26%	3.39%	9.60%	13.56%	5.08%	3.39%	2.26%	1.13%	5.08%	8.47%	1.69%	1.69%
18:00	1.13%	2.26%	3.39%	4.52%	2.82%	1.13%	1.69%	1.69%	2.82%	5.08%	1.13%	0.56%
19:00	0.56%	1.69%	2.26%	3.95%	2.26%	1.13%	1.69%	2.26%	1.13%	5.08%	1.13%	0.56%
20:00	0.56%	2.26%	2.82%	3.39%	1.69%	1.13%	0.56%	1.69%	1.13%	7.34%	1.13%	0.56%
21:00	1.13%	2.82%	5.65%	2.82%	1.69%	1.69%	0.56%	1.69%	2.26%	10.17%	1.69%	1.69%
22:00	1.69%	3.39%	7.34%	5.08%	3.39%	2.82%	0.56%	1.69%	2.82%	11.30%	2.82%	2.26%
23:00	4.52%	5.65%	13.56%	11.30%	7.91%	5.08%	1.13%	2.26%	4.52%	14.69%	4.52%	4.52%

Source: Ausgrid, Energeia

Rooftop PV penetration in Ausgrid's network is currently estimated to be around 11%, and current load patterns do not therefore provide accurate estimates of solar PV congestion periods. Energeia therefore looked at SAPN, whose rooftop solar PV is approaching 31% of residential premises, and the comparative results of that analysis are reported in the figure below, which shows December from noon to 1pm as being the peak period.

Figure 36 – Current Solar PV Congestion Signalling (SAPN)

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
0:00	3.82%	4.46%	12.10%	8.92%	8.92%	10.83%	8.28%	7.64%	10.19%	9.55%	5.10%	3.18%
1:00	7.64%	7.01%	15.92%	10.83%	20.38%	14.65%	9.55%	9.55%	9.55%	17.20%	13.38%	5.73%
2:00	14.01%	12.74%	23.57%	17.20%	18.47%	26.11%	19.75%	15.29%	16.56%	20.38%	14.65%	10.19%
3:00	15.29%	14.65%	25.48%	19.11%	17.83%	28.66%	21.02%	15.92%	19.75%	22.29%	16.56%	12.74%
4:00	15.29%	12.10%	26.11%	17.83%	17.83%	30.57%	21.02%	15.92%	20.38%	24.84%	17.20%	13.38%
5:00	10.83%	8.92%	21.66%	16.56%	13.38%	28.03%	20.38%	14.01%	19.11%	22.29%	15.92%	9.55%
6:00	2.55%	1.91%	13.38%	7.01%	7.64%	29.30%	17.20%	5.73%	16.56%	17.83%	12.74%	6.37%
7:00	2.55%	0.64%	7.64%	1.27%	1.27%	24.20%	12.74%	0.64%	9.55%	14.65%	5.73%	2.55%
8:00	3.18%	0.64%	6.37%	1.91%	1.27%	21.02%	12.10%	0.64%	6.37%	19.11%	4.46%	1.27%
9:00	2.55%	1.27%	8.28%	6.37%	7.01%	33.12%	18.47%	3.18%	4.46%	29.94%	2.55%	1.91%
10:00	2.55%	8.28%	27.39%	31.21%	33.76%	55.41%	38.85%	12.74%	12.10%	49.68%	10.83%	2.55%
11:00	3.82%	22.29%	48.41%	49.68%	51.59%	67.52%	58.60%	39.49%	31.85%	65.61%	29.30%	10.19%
12:00	7.01%	24.84%	48.41%	52.87%	53.50%	71.34%	60.51%	46.50%	42.68%	64.33%	36.31%	9.55%
13:00	5.73%	30.57%	52.23%	54.14%	52.23%	71.97%	61.15%	46.50%	47.13%	67.52%	39.49%	12.74%
14:00	5.10%	22.93%	46.50%	56.05%	50.96%	68.79%	61.15%	48.41%	43.95%	60.51%	30.57%	11.46%
15:00	5.10%	8.28%	25.48%	50.96%	49.68%	64.97%	56.05%	43.95%	42.68%	37.58%	14.01%	4.46%
16:00	0.64%	2.55%	21.02%	35.03%	36.94%	52.87%	33.76%	28.66%	19.11%	10.83%	5.10%	2.55%
17:00	0.64%	0.64%	14.65%	5.10%	3.82%	10.83%	7.01%	3.18%	5.10%	4.46%	2.55%	2.55%
18:00	0.64%	0.64%	14.65%	1.91%	1.27%	5.10%	2.55%	1.27%	1.91%	4.46%	1.91%	1.27%
19:00	0.64%	0.64%	12.74%	1.27%	2.55%	5.10%	1.27%	0.64%	1.91%	3.82%	2.55%	3.18%
20:00	1.91%	0.64%	13.38%	1.91%	1.91%	5.10%	1.27%	0.64%	1.91%	3.82%	3.18%	3.18%
21:00	2.55%	1.27%	12.74%	2.55%	2.55%	3.82%	1.91%	0.64%	3.18%	5.10%	4.46%	3.82%
22:00	1.91%	1.91%	12.10%	3.18%	3.82%	5.10%	2.55%	3.18%	4.46%	7.01%	5.73%	3.82%
23:00	3.18%	2.55%	14.01%	6.37%	7.01%	10.19%	3.18%	7.01%	7.64%	8.28%	5.73%	5.10%

Source: SAPN, Energeia

The above analysis is important for setting rooftop solar PV pricing, which needs to reflect marginal costs and congestion timing to be efficient, as well as for setting consumption pricing, which should, in theory reflect the same cost structure, but inverted, as an additional kWh of load near to the point of solar PV generation, avoids the solar PV driven costs. SAPN's recently introduced solar soaker tariff is designed along these lines with its period set from 10am to 3pm every day.

5.1.3.4 Gross Metering

Providing pricing signals to reflect the marginal cost of the above solutions is efficient and equitable, provided price signals can be charged on a gross metering basis. Gross metering ensures that the actual contribution of a given solar PV system is charged, rather than the net effects, which will favour relatively large daytime electricity consumers over relatively small ones, which are more likely to export.

Forward looking, dynamically set pricing signals used to coordinate solar PV generation across the network's connected assets will solicit efficient levels and operation of DER to manage demand as required by the Rules[55]. Near-term, network pricing reforms are urgently needed that reflect rooftop solar PV LRMC to avoid substantial uneconomic investment in solar PV generation and consumption patterns.

5.1.4 DER Network Tariffs

One of the key advantages of DER is that it can be generated close to where it is consumed. Buying electricity from one's neighbour only requires, in principle, the LV conductor between the two homes, and there are fewer electrical losses. Removing barriers in the current pricing paradigm, which presumes power travelling from distant utility scale generators over a range of voltages to consumers, is essential to removing a key barrier to DER's economic usage. Likewise, a DER network pricing approach will also need to charge more when DER is being exported to higher voltages, as it is using more of the grid, and losses will be higher.

There are many ways that the above system could be implemented, and it is important to note that electricity network revenues would need to continue to recover the efficient costs of providing an efficient service. A certificate system could be used here, for example, whereby DER generators receive a certificate for the time and nodal location of their generation, which could be used by consumers in the same nodal location to obtain a rebate on the network charges they incurred for the consumption associated with the certificate. During periods of reverse flow, the electrical location would broaden, but the rebate would be lower due to use of more assets.

Charging DER exports for the incremental costs they incur (e.g. additional asset capacity), combined with not charging DER exports for grid assets not being used (e.g. LV transformers, HV feeders, etc.), and fairly allocating

[55] Ibid.

any residual sunk costs between consumers that use the central and decentralised electricity systems, is necessary for optimal DER investment and operation over the long-term.

5.1.5 DER Tariff Assignment

Changing existing tariffs to address the issues identified above due to solar PV, or due, for example, to an EV driver who is not charged the true cost of charging during the network peak period, is likely to be infeasible due to the significant impacts it is likely to have on all consumers, and the politics involved.

Requiring consumers that invest in solar PV, storage or an EV to move on to a more cost reflective tariff designed to mitigate the issues identified above via changes to the LRMC and congestion periods, is likely to be more practicable, particularly in the near term.

This issue is being addressed in the DER access arrangements rule change[56], where DNSPs will have to make transitional arrangements for existing DER customers until 2025, who have made investment decisions based on the current state of the market.

Establishing tariff assignment policies that move consumers investing in DER, especially, rooftop solar PV, an EV or storage, on to a more cost reflective tariff is necessary for efficient levels and operation of DER.

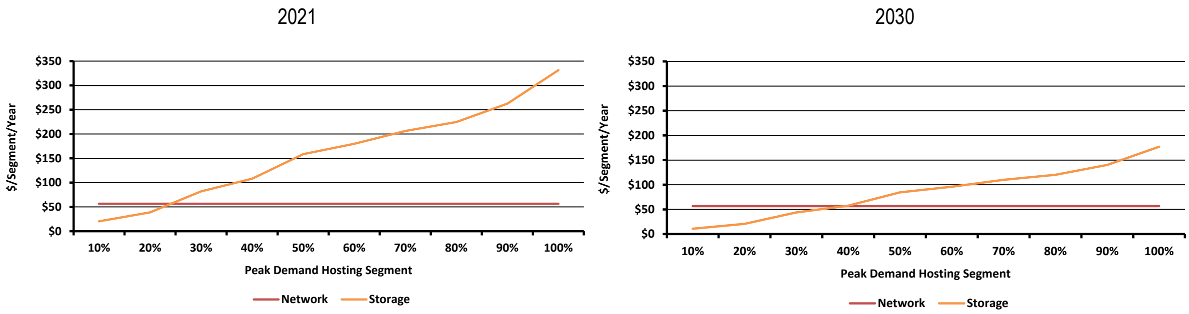
5.1.6 Holistic Investment Optimisation

Energeia analysed the costs of using different combinations of DER and network solutions to address a typical peak demand profile to determine the optimal level of DER and network investment, and to inform our understanding of the potential barriers to achieving the optimal mix.

5.1.6.1 Falling DER Technology Costs

The results of Energeia's analysis of the relative economics of LV investment given network LV LRMC, storage costs net of NEM service revenues, and a typical load profile is reported in the figure below. It shows that around 25% of peak demand would be more cost effectively met by DER than network capacity today. By 2030, close to the time when the storage asset will need to be replaced, the shares increase to 40%. Considering future DER replacement costs is therefore critical for optimising the overall investment solution.

Figure 37 – Optimal Levels of DER Investment to Meet Peak Demand by Year



Source: Energeia

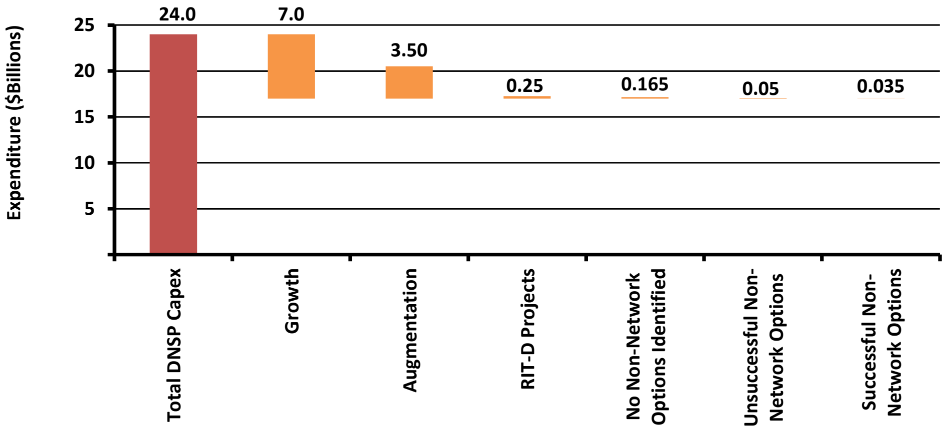
5.1.6.2 Zone Substations and Sub-Transmission Lines

Energeia's review of recent levels of network services provided by DER found they are not yet achieving the above share of investment. The figure below from the AEMC shows that for a partial list of network investments, being capital projects valued at over $5m, with a total value of $24b in 2018, DER revenues amounted to 0.15%

[56] AEMC (2021), National Electricity Amendment (Access, Pricing And Incentive Arrangements For Distributed Energy Resources) Rule 2021, https://www.aemc.gov.au/sites/default/files/2021-08/Final%20determination%20-%20Access%2C%20pricing%20and%20incentive%20arrangements%20for%20DER.pdf

of the total, or around $35m. It is important to point out that the RIT-D[57] process mainly involves zone substation and sub-transmission projects, which have a significantly lower LRMC than LV and HV assets.

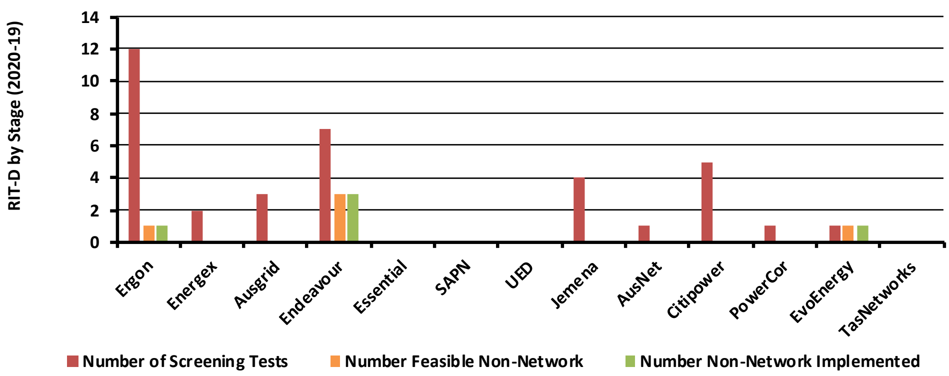
Figure 38 – RIT-D Outcomes by Reporting Stage



Source: AEMC

As the above analysis was completed in 2018, Energeia examined the last two years of RIT-D review to determine whether a change in DER revenues could be seen, heading in the direction of the efficient levels identified in the figure above. The result of our review is reported in the figure below, which shows that the percentage of RIT-D projects implementing DER over the last three years is significantly higher than 0.15%, however, it remains far below the 25% level our high-level analysis indicated as being efficient.

Figure 39 – DNSP RIT-D Outcomes (2019-21)



Source: Energeia, DNSPs

In almost every case that Energeia reviewed, the key barrier to DNSPs using DER was the lack of sufficient DER capacity. Implementing the recommended changes to LRMC and network pricing will support achievement of the optimal levels of DER investment identified above. However, consideration of addressable downstream and upstream network investments and associated benefits is essential to making efficient investment decisions.

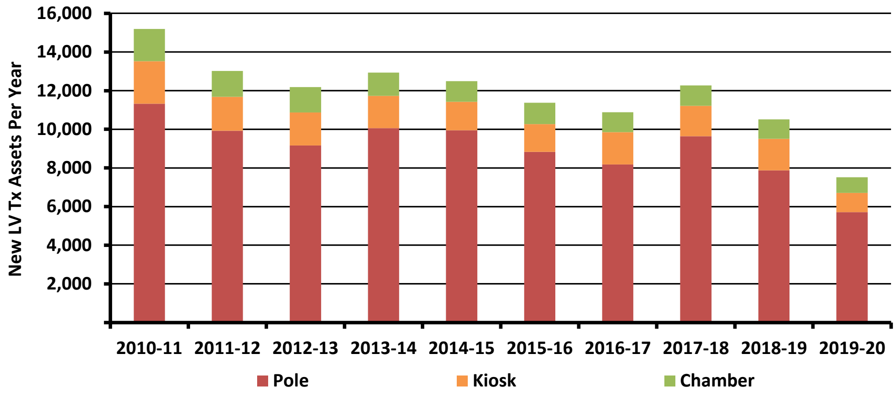
As mentioned previously, sub-transmission and zone substation assets are relatively low cost, meaning that on a stand-alone basis, DER will be less competitive using this approach. *The key to achieving efficient levels of DER investment is to ensure that DER is able to compete across the range of addressable network investment, down to the LV network level. Benefits from avoided investment at lower voltages can be used to offset its costs at the zone substation and sub-transmission level, making DER far more competitive overall.*

[57] RIT-D is short for the Regulatory Investment Test for Distribution that is required for all capital projects valued over $5m.

5.1.6.3 LV Transformers and Substations

In order to illustrate the scale of the opportunity related to reducing network costs across the network by leveling the playing field down to the LV network, Energeia researched the total number of LV transformers deployed each year and their approximate value using Regulatory Information Notice (RIN) data, which is reported in the figure below by asset sub-type. The research shows that LV transformer projects are three orders of magnitude greater than RIT-D projects.

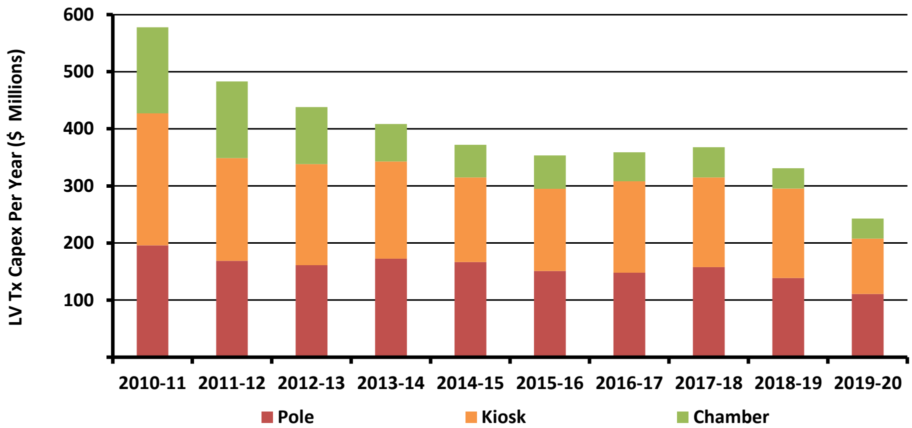
Figure 40 – Total LV Transformer Projects in the NEM (2010-19)



Source: Energeia, DNSPs

Energeia then calculated the total value of investment in the LV transformer asset class using distribution network (network) reported unit prices from their replacement capex models where available or estimating them using comparable networks where they were not. The figure below reports on the resulting annual capital expenditure across the National Electricity Market (NEM) on LV transformers and substation projects. The analysis shows that DER addressable LV transformers and substations, as an asset class, are more valuable than zone substation and sub-transmission asset classes combined.

Figure 41 – Total LV Transformer Project Capital Expenditure in the NEM (2010-19)



Source: Energeia, DNSPs

Energeia notes a reduction of 31% of the reported cost of LV transformers and substations over the last five years, with a 34% decrease in the volume of assets, suggesting a marginal increase in the unit price. Based on the results of our economic modelling, leveling the playing field for DER to provide network services to reduce or avoid LV transformer and substation investments could reduce these costs for consumers.

5.1.6.4 HV Feeders and Sections

Investment in HV sections as well as whole feeders to manage thermal, security or reliability constraints is another major class of assets the costs for which Energeia's analysis suggests could be reduced using DER.

Holistic network planning, which considers the full range of network constraints over a reasonable planning period, is essential to ensure the overall least cost mix of network and DER investments are able to be made.

In summary, taking wholesale market revenues, lower future costs, and upstream network investments into account is necessary for efficient levels of DER investment.

5.2 DER Enablement

Successfully integrating the levels of DER in the Consumer High DER scenario will require robust planning, operational and market systems capable of managing millions of devices in real-time.

Energeia has identified the following DER enabling measures based on our research of international best practice DER integration, and our own experience working in the US and Australia:

- Integrated Distribution Resource Planning
- Distributed Energy Resource Management Systems
- Distributed Energy Market Systems

While each of the above measures reflects current practice at the wholesale level with hundreds of nodes and thousands of transmission assets, they have not been implemented at the scale of the LV transformer, which is around two orders of magnitude larger by volume.

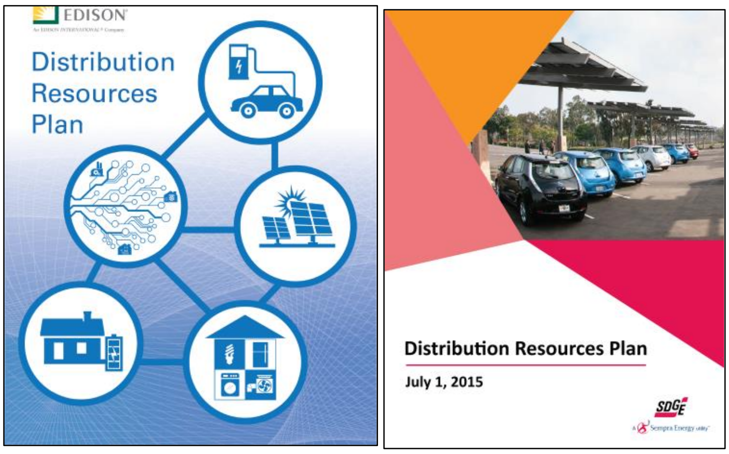
The sections below focus on what Energeia views as the most important enablement measures; each will involve addressing a host of related technical issues as well which are beyond the scope of this report.

5.2.1 Holistic Distribution Resource Planning

A key limitation of the Distribution Annual Planning report (DAPR) and associated RIT-D process is that it only covers a fraction of total network investment, providing only a partial picture to potential DER investors, DER aggregators and DER resource developers[58]. The latter role is particularly critical for ensuring efficient levels of DER investment. DER aggregators are critical for the efficient operation of DER once it has been developed.

Energeia's review of international best practice has found that leading jurisdictions provide holistic distribution system plans to the public (see the figure below), which consider DER potential as part of the plan, down to the LV transformer. This contrasts with the DAPR, which is limited by the Rules to zone substations[59]. Energeia understands that DAPRs were limited to zone substations due to perceived transactional costs, however, modern software enables cost effective identification of optimal DER-integrated systems down to the HV level.

Figure 42 – *Holistic Distribution Resource Plans*



[58] A DER resource developer develops DER to serve a network or wholesale market opportunity.

[59] The Rules make HV feeders optional.

Source: Southern California Edison, San Diego Gas and Electric

By planning the distribution system on a holistic basis, it is possible to consider and address the key issues raised in the previous section including consideration of all wholesale and distribution asset investments. The other major benefit of a holistic analysis is that the full size of the DER opportunity can be better understood and communicated to the market.

Potential DER developers, investors and aggregators are therefore more likely to make significant investments in capability and capacity against a system wide, 10-year investment plan covering assets down to the LV level, than on the basis of less than half of these investments, which is the case with the current DAPR.

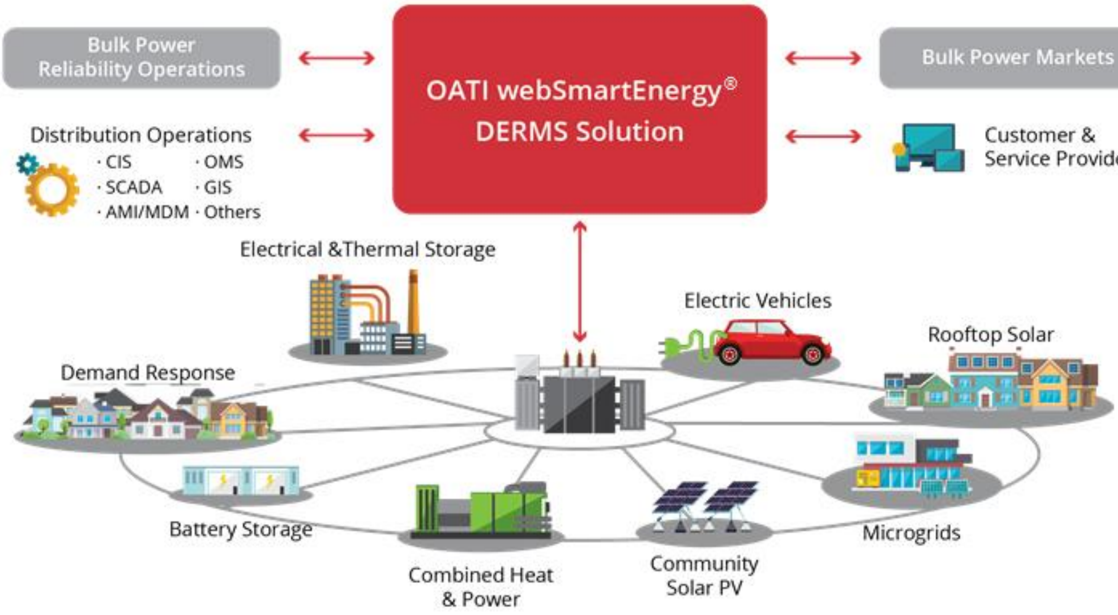
Requiring holistic distribution resource plans down to the LV level across at least a 10-year basis is necessary to enable efficient investment in DER enablement capability and capacity.

5.2.2 Distributed Energy Resource Management Systems

Energeia's Virtual Power Plant (VPP) optimised loads reported in Section 5.2.3 and the Cost-Benefit-Assessment (CBA) results reported in Section 7 are premised on effective orchestration of millions of DER devices, including solar PV and battery inverters, EV chargers and water heaters, as well as the constraint engines and systems needed to ensure their effective operation.

DERMS are designed to enable networks to orchestrate DER across their systems. They may be part of an Advanced Distribution Management System (ADMS) or a stand-alone system. The figure below illustrates the role played by a DERMS, operating between the network, DER and the bulk power system including associated ancillary services and other markets.

Figure 43 – Illustration of a DERMS / Technical Constraint Engine



Source: OATI

Current efforts in Australia to deploy DOEs are consistent with the above DER integration architecture, focused on the constraint engine element. The constraint engine is needed to determine safe operating envelopes, which may be used by third parties to optimise DER operation including responding to wholesale power market signals.

In addition to supporting a network's role in delivering a safe, secure, reliable electricity service to the specified quality standard, a DERMS also enables distribution networks to manage DER under their direct control, for example, to address voltage, thermal, security or reliability constraints. How this control operates, and whether it is via direct device communication, an AEMO provided business-to-business (B2B) service transaction, or an industry standard Application Programming Interface (API), is beyond the scope of this report.

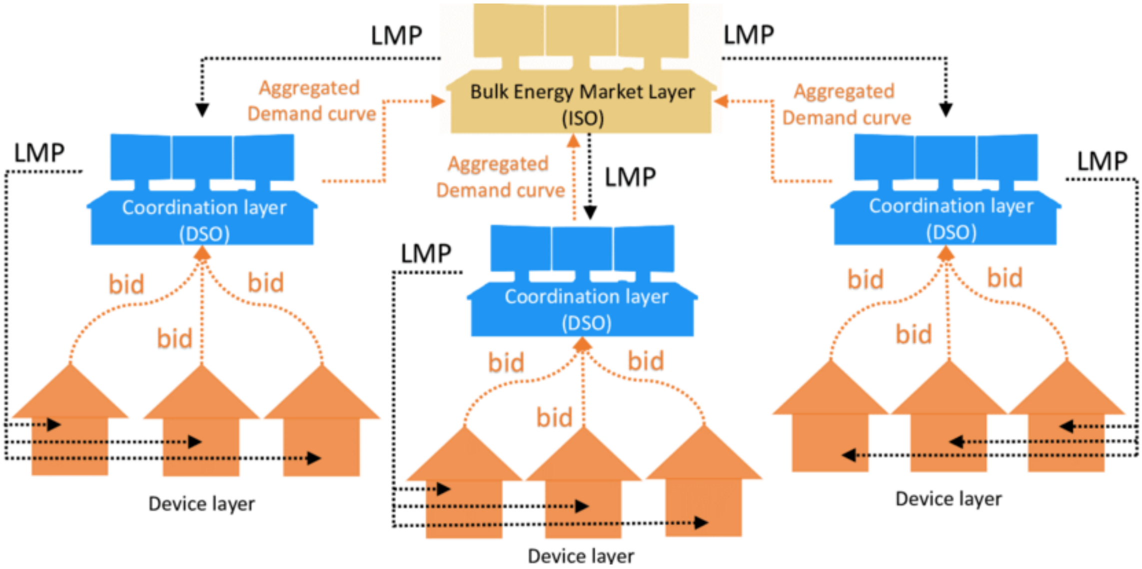
Establishing network and industry[60] capability and capacity to orchestrate millions of DER devices is necessary to achieve optimal levels of DER investment and operation.

5.2.3 Distributed Market Systems

DERMS are focused on the successful technical orchestration of millions of devices across a dynamically configured distribution network with multiple types of technical constraints without violating any of them. Distributed market systems are focused on coordinating financial transactions to economically optimise DER operation, and ultimately investment.

The figure below illustrates a Distribution System Operator (DSO) coordinated distributed market architecture. In this architecture, the DSO provides Locational Marginal Prices (LMPs) to each participant, based on their bids and distribution and transmission network constraints. The DSO also interfaces with the Independent System Operator (ISO), which is AEMO in Australia, to manage transmission constraints and wholesale market LMPs.

Figure 44 – Markets (DSO not Transactive Model Shown)



Source: PNNL, "AEP Ohio gridSMART Demonstration Project Real-Time Pricing Demonstration Analysis," Pacific Northwest National Laboratory, Richland WA, Tech. Rep. PNNL-23192, Feb. 2014.

There are multiple potential distributed market architectures that could be deployed in Australia, and the selection criteria is beyond the scope of this report. Another popular distributed architecture, sometimes termed 'transactional energy', distributes the market clearing function across all participants. A third architecture, now out of favour, sees an independent market operator function separate to the system operation function.

Establishing network and industry[61] capability and capacity to clear and settle distributed energy markets down to the LV transformer is necessary to achieve optimal levels of DER investment and operation.

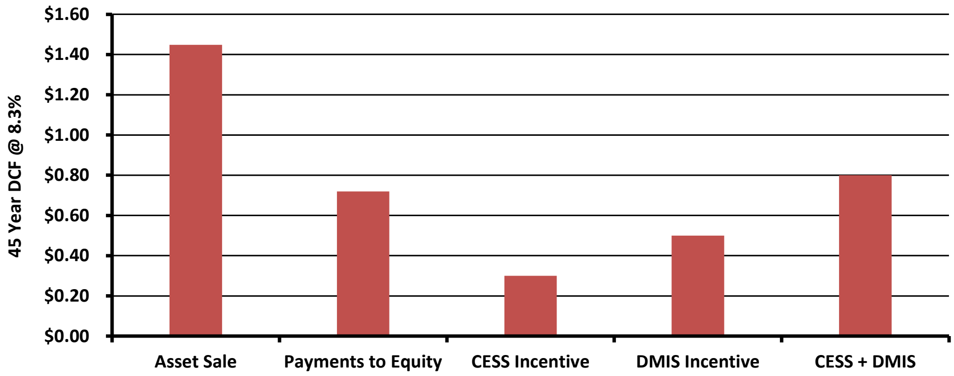
5.3 Network Incentives

The National Electricity Rules (Rules) have established a constellation of performance incentives, however, Energeia's analysis shown below in Figure *45* has found that current settings appear to be sending the wrong signals to DNSPs and their shareholders. Energeia's analysis shows investing in network assets remains the largest incentive by far due to its multiplier effect on the valuation of network businesses during a sale.

[60] Whether this is provided by AEMO, DNSPs and/or a third party needs to be determined.

[61] Again, whether this is provided by AEMO, DNSPs and/or a third party needs to be determined.

Figure 45 – Discounted Present Value Returns to Shareholders of $1 in Capex by Incentive



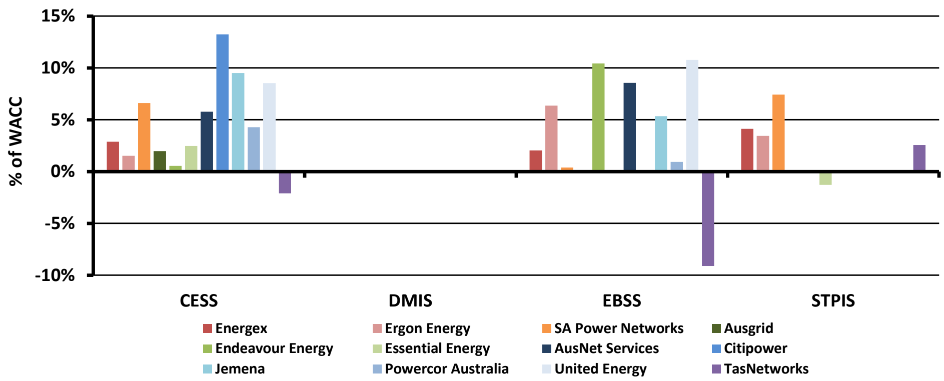
Source: AER, Energeia Research
Notes: The 8.3% nominal equity value used to discount 45-year cashflows is an average of recent allowances.

The above analysis also shows that discounted payments to equity are 140% the value of the Capital Efficiency Sharing Scheme (CESS) incentive, and 44% higher than the Demand Management Incentive Scheme (DMIS) incentive. Energeia's analysis shows that combining the two delivers a 11% higher return than capex. However, as is demonstrated below, DNSPs have not to date been able to realise the DMIS, with total reported DMIS payments over the last five years amounting to $1.6m in payments, or less than 0.01% of returns to capital over the period (see Figure *46*).

Although Energeia's analysis shows that the DMIS incentive is twice as high as the CESS incentive per $1 avoided, the analysis below shows that DNSPs are only realising payments for the CESS, which suggests that there may be significant barriers to realising the DMIS.

The figure below reports on the incentives received by incentive type, normalized by each network's WACC to enable comparison of networks of different sizes. The research shows that while the CESS and Efficiency Benefit Sharing Scheme (EBSS) resulted in comparable incentive payments to networks, the number of payments due to implementation of non-network alternative solutions covered under the DMIS, which would be virtually any DER related project, are less than 0.01% over the period for all DNSPs combined.

Figure 46 – Incentives Earned as a Percentage of Approved Expenditure



Source: AER, Energeia Research

As long as the Rules are sending signals to investors to increase network capital expenditure in order to maximise returns, economically rational investors will continue to incentivise executive management to prioritise regulator approved capital expenditure.

Energeia notes that the increase in shareholder returns from increased capital expenditure may be partially offset by the increased risk of stranded assets in the future. However, there is no mechanism under the electricity rules to write-down asset values, unlike the gas rules, which do allow for asset write-downs.

Based on the above analysis, Energeia concludes that the current incentive system does not incentivise efficient investment in DER as a non-network solution, and that this is at least in part due:

- Barriers in the DMIS, which are preventing DNSPs from pursuing this incentive;

- Shareholders seeing a 140% higher return from AER approved capex than the CESS; and
- Shareholders seeing 383% higher total return from AER approved capex than the CESS + DMIS.

Based on the above analysis, Energeia believes that the key to incentivising networks to support the achievement of optimal levels of DER investment includes:

- **Removing barriers in the DMIS or increasing incentive levels** – Allowing the full range of estimated benefits, including future LV or HV network benefits, and providing key information to the market via a Integrated Distribution Resource Plan (IDRP), as highlighted in previous sections, may help reduce barriers to implementing more non-network alternatives by DNSPs.
- **Delinking network investment from network valuations** – Policymakers and regulators will need to break the current nexus that demonstrably exists between network investment and business valuation. Doing so will unleash networks to effectively drive and lead the key measures described in this section.

In summary, customers and networks will both benefit from a regulatory incentive system that effectively delivers higher, long-term value for shareholders for commensurate, sustainable reductions in customers long-term costs, holding system security, reliability, environmental and safety performance constant.

6 The Case for Change

Energeia developed estimates of total system costs for each of the scenarios over 15 and 30-year time horizons. Our estimate of the net benefits of the Consumer High DER scenario over the ISP Step Change scenario is based on the difference in discounted present value. Energeia plans to compare a wider range of ISP scenarios including those being developed for the latest ISP update, in future work.

Our analysis of the key network and generation costs impacted by DER adoption has found that the Consumer High DER scenario would save consumers $25b in costs to 2035, and $69b in costs to 2050. The modelling shows that the substantially higher cost of solar PV in the Consumer High DER scenario compared to the ISP Step Change scenario is more than offset by network and generation cost savings.

The following sections detail our cost and benefit assessment framework, methodology and results.

6.1 Assessment Methodology

Energeia's assessed the net benefits of the Consumer High DER scenario compared to the ISP Step Change scenario by comparing their total costs over the modelling period discounted to present value. The purpose of the assessment is to determine whether there is an economic case for stakeholders to pursue the Consumer High DER scenario, at least compared to the ISP Step Change scenario, and its magnitude.

The table below summarises the key costs that Energeia's Cost-Benefit-Assessment (CBA) considered, grouped by cost impacted stakeholder. We have also characterised the nature of the cost, i.e. whether the cost is an economic cost, or a wealth transfer. We note that market costs that differ from changes in underlying generator costs represent a transfer of wealth between generators and consumers.

Table 5 – Cost Assessment Framework

Stakeholder	Cost Category	Type of Cost	Description
Consumer	Petrol Costs	Economic	Includes the average annual cost of petrol for the average consumer by state
	Natural Gas Costs	Economic	Includes the average annual cost of natural gas for the average consumer by state
	Solar PV Costs	Economic	Includes the annualised capital expenditure costs of solar PV capacity based on the purchase year
	Storage Costs	Economic	Includes the annualised capital expenditure costs of BTM storage capacity based on the purchase year
Network	Capital Expenditure	Economic	Includes the annualised capital expenditure costs of required network capacity based on the assumed LRMC
	Operational Expenditure	Economic	Includes the annual operational costs for required network capacity based on an assumed 2.5% of capital expenditure cost
Market	Energy Costs	Transfer	Includes the value of wholesale market turnover, i.e. hourly consumption multiplied by the hourly price
	CO2 Costs	Environmental	Includes the average cost of carbon ($/tonne CO2)

Source: Energeia research

Energeia acknowledge a number of limitations in our CBA scope and approach, including:

- Network costs are approximated by multiplying LV coincident peak demand by the LV LRMC value for a given network, and are not based on actual network investment timing across LV, HV and sub-transmission voltage levels[62]
- Not all network costs have been included, e.g. network decommissioning or sunk costs, customer driven costs or other fixed costs not driven by demand or customer levels
- Not all DER integration costs have been included, e.g. solar PV hosting capacity costs are limited to thermal constraints, and no costs have been assumed for virtual power plant (VPPs) constraint or orchestration management costs, however, they are expected to be relatively immaterial[63]

Energeia also notes that our two scenarios do not vary by rate of vehicle or building electrification, however, we plan to vary these assumptions in future work.

6.2 Cost-Benefit-Assessment

The results of Energeia's 15-year and 30-year discounted present value comparisons of the Consumer High DER and ISP Step Change scenarios is reported in the figures on the following page.

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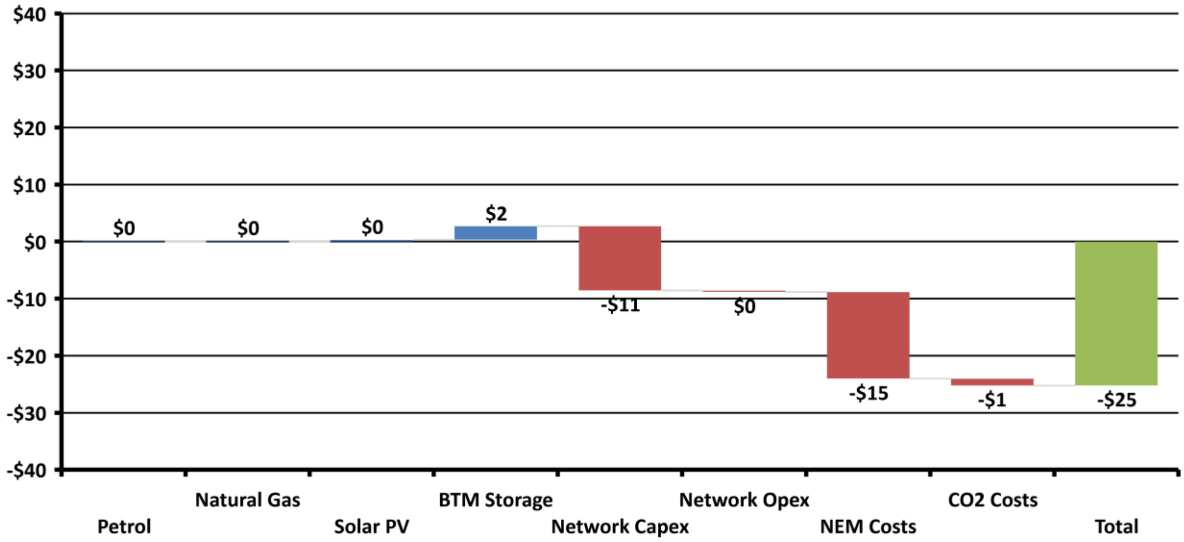
[62] This is comparable to network approaches used in LRMC calculations, which typically rely on only one voltage level.

[63] Please see our Phase 1 report for detailed information about the range of integration costs and their relative costs, available at: https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf

The 15-year analysis to 2035 shows that realising the Consumer High DER scenario would save consumers $25b compared to our modelling of the ISP Step Change scenario, mainly due to $11b in lower network costs, and $15b in lower NEM settlement costs, which is partially offset by $3b in higher DER costs.

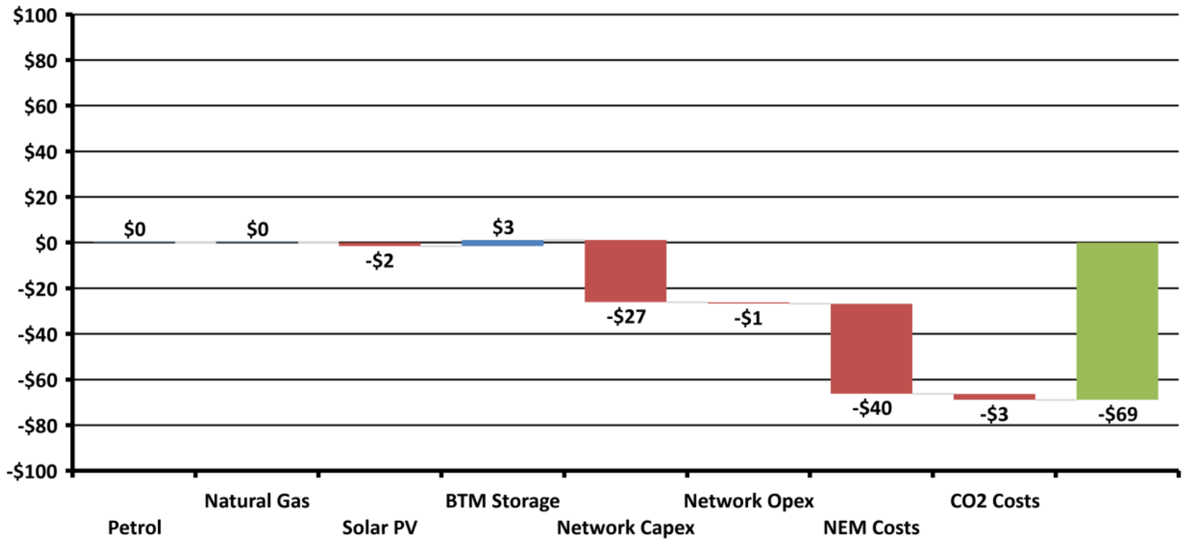
Figure 47 – Costs and Benefits of Consumer High DER Compared to ISP Step Change (15 Years)



Source: Energeia modelling

Over the 30-year period to 2050, the Consumer High DER scenario is $69b less for consumers, driven mainly by $27b in lower network capex costs and $40b in lower NEM settlement costs, partially offset by $3b in higher behind-the-meter storage costs. Rooftop solar PV costs are lower than under the ISP Step Change scenario, despite significantly more rooftop capacity, due to the post-2040 timing of most of the investment.

Figure 48 – Costs and Benefits of Consumer High DER Compared to ISP Step Change (30 Years)



Source: Energeia modelling

The table below displays the CBA analysis results in tabular format for the 15-year and 30-year CBAs. Energeia has looked at net benefits over two time scales to better understand the timing of net benefits, and whether the net benefits seen in the Consumer High DER scenario vary over time. Based on the results of our modelling, and despite significant changes in DER and generation prices over time, Energeia concludes that the relative cost savings of the Consumer High DER scenarios is consistent over time.

Table 6 – Cost Assessment Results by Cost Category and Assessment

Discounted Present Value to 2035

		Energeia Consumer	AEMO Step Change	Difference
Consumers	Petrol Costs	$193,972	$193,972	$0
	Natural Gas Cost	$68,664	$68,664	$0
	Solar PV Costs	$7,260	$6,912	$348
	Storage Costs	$6,516	$4,152	$2,364
Networks	Capex	$64,559	$75,814	-$11,255
	Opex	$1,614	$1,895	-$281
Market	Energy Costs	$44,478	$59,694	-$15,216
	CO2 Costs	$13,175	$14,383	-$1,208
Total incl. Market Costs		**$387,064**	**$411,104**	**-$25,249**

Discounted Present Value to 2050

		Energeia Consumer	AEMO Step Change	Difference
Consumers	Petrol Costs	$272,690	$272,690	$0
	Natural Gas Cost	$110,857	$110,857	$0
	Solar PV Costs	$14,841	$16,495	-$1,655
	Storage Costs	$10,822	$7,910	$2,912
Networks	Capex	$93,635	$120,989	-$27,354
	Opex	$2,341	$3,025	-$684
Market	Energy Costs	$57,631	$97,150	-$39,519
	CO2 Costs	$15,502	$18,100	-$2,598
Total incl. Market Costs		**$578,319**	**$647,217**	**-$68,898**

Source: Energeia modelling

Appendix A – Glossary of Key Terms

Table A1 – List of Acronyms

Key Term	Definition
ABS	Australian Bureau of Statistics
AC	Alternating Current
ACOSS	Australian Council of Social Service
AEC	Australian Energy Council
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ANU	Australian National University
APVI	Australian Photovoltaic Institute
ARENA	Australian Renewable Energy Agency
ARIMA	Auto-Regressive Integrated Moving Average
B	Bus
BEV	Battery Electric Vehicle
BSL	Brotherhood of St. Laurence
BT	Block Tariff
BTM	Behind the Meter
CBA	Cost-Benefit Assessment
CBD	Central Business District
CCGT	Closed Cycle Gas Turbines
CEC	Clean Energy Council
CEFC	Clean Energy Finance Corporation
CET	Clean Energy Target
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated Solar Thermal
CVGA	Central Victorian Greenhouse Alliance
DC	Direct Current
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resource
DM	Demand Management
DNSP	Distributed Network Service Provider
DoD	Depth of Discharge
DR	Demand Response
ECA	Energy Consumers Australia
ECA	Energy Consumers Australia
EE	Energy Efficiency
ENA	Energy Networks Australia
ENA	Energy Networks Australia
EQL	Energy Queensland
ESC	Essential Services Commission
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FD	Feeder
FiT	Feed-in Tariff
HEV	Hybrid Electric Vehicle'
HV	High Voltage
HVAC	Heating, Ventilating, and Air Conditioning
ICE	Internal Combustion Engine
IEEE	Institute of Electrical and Electronics Engineers
ISP	Integrated System Plan
kVA	Kilo-Volt-Amperes
kW	Kilowatt
kWh	Kilowatt hour
L2	Level 2 Charging

LC	Light Commercial
LCOE	Levelised Cost of Energy
LRET	Large-scale Renewable Energy Target
LRMC	Long-Run Marginal Cost
LV	Low Voltage
MW	Megawatts
NAGA	Northern Alliance for Greenhouse Action
NE Solar	New England Solar Power
NEM	National Electricity Market
NEO	National Electricity Objectives
NMI	National Meter Identifier
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NSW DPIE	New South Wales Government Department of Planning, Industry and Environment
NTR	Network Transformation Roadmap
NUOS	Network Use of System
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbines
OEM	Original Equipment Manufacturer
OLTC	On-Load Tap Changer
PC	Passenger Car
PEV	Plug-In Electric Vehicle
PHES	Pumped Hydroelectric Energy Storage
PHEV	Plug-In Hybrid Electric Vehicle
PIAC	Public Interest Advocacy Centre
PV	Photovoltaic
PWC NT	Northern Territory Power and Water Company
R&D	Research and Development
RAB	Regulatory Asset Base
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
ROI	Return on Investment
RRO	Retailer Reliability Obligation
RRP	Regional Reference Price
RT	Rigid Truck
SA DEM	South Australian Government Department of Energy and Mining
SAIDI	System Average Interruption Duration Index
SAPN	South Australia Power Networks
SAPS	Stand-Alone Power Systems
SCED	Security-Constrained Economic Dispatch
SEC	State Electricity Commission of Victoria
SGSC	Smart Grid Smart City
SRMC	Short-Run Marginal Cost
STATCOM	Static Synchronous Compensator
STC	Small-Scale Technology Certificate
STS	Standard Trading Service
SUV	Sport Utility Vehicle
SVPD	St Vincent de Paul Society
SWIS	South West Interconnected System
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
ToU	Time of Use
UFLS	Under Frequency Load Shedding
Uni NSW	University of New South Wales
Uni QLD	University of Queensland
US	United States

UTS	University of Technology Sydney
VAGO	Victorian Auditor-General's Office
VCR	Value of Customer Reliability
VIC DELWP	Victorian Government Department of Environment, Land, Water and Planning
VPP	Virtual Power Plant
WACC	Weighted-Average Cost of Capital
WEM	Wholesale Electricity Market
ZS	Zone Substation

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Appendix C – Detailed DER Optimisation Results

	Residential Electrification Segments				Commercial & Industrial Segments		
	None	Transport	Buildings	Both	Office	Retail	Industrial
NSW							
2025							
PV	4	6	6	6	40	40	20
Storage	2	0	2	2	20	20	0
2030							
PV	6	6	8	8	40	40	30
Storage	2	2	4	2	20	40	0
2040							
PV	10	10	10	10	60	60	60
Storage	6	8	6	8	40	40	60
2050							
PV	10	10	10	10	50	60	60
Storage	8	10	8	10	40	60	80
VIC							
2025							
PV	6	6	6	6	40	50	30
Storage	2	2	2	2	20	20	0
2030							
PV	6	6	8	8	50	50	40
Storage	4	2	4	2	40	40	20
2040							
PV	10	10	10	10	60	60	60
Storage	6	10	6	10	40	40	60
2050							
PV	10	10	10	10	50	60	60
Storage	8	10	6	10	40	60	80
QLD							
2025							
PV	4	4	6	6	30	40	20
Storage	2	2	2	2	20	20	0
2030							
PV	6	6	6	6	40	40	30
Storage	4	2	2	2	40	40	20
2040							
PV	10	10	10	10	60	60	60
Storage	6	10	6	10	40	40	80
2050							
PV	10	10	10	10	60	60	60
Storage	8	10	8	10	60	60	80
SA							
2025							
PV	4	6	6	6	40	40	20
Storage	2	2	4	2	40	20	0
2030							
PV	6	6	8	8	40	50	30
Storage	4	4	4	4	40	40	20
2040							
PV	10	10	10	10	60	60	60
Storage	6	10	6	10	40	40	80
2050							
PV	10	10	10	10	60	60	60
Storage	8	10	8	10	60	60	80
TAS							
2025							
PV	4	6	6	6	50	50	20
Storage	2	0	2	2	20	20	0
2030							
PV	6	6	8	8	50	50	30
Storage	2	2	4	2	40	40	0
2040							
PV	10	10	10	10	60	60	60
Storage	6	8	6	8	40	40	60
2050							
PV	10	10	10	10	60	60	60
Storage	8	10	8	10	40	40	80

Appendix D – Stakeholder and Subject Matter Expert Consultation

D.1 Summary of Consultation Process

Energeia undertook multiple stages of stakeholder and subject matter expert consultation to validate key inputs and assumptions as well as results and insights. Consultation included targeted stakeholder meetings, peer review of our methodology report and stakeholder feedback on the final report.

D.2 Reference Group

The Reference Group terms of reference stated that the role of members of the Reference Group was to provide input (on behalf of their organisations) into the issues and analysis being investigated by Energeia and Renew for the project. This included:

- undertaking a preliminary interview with the Consultant, to assist with project scope;
- providing data/evidence (as far as is possible/practicable) for input into technical investigations, analysis and modelling that will be undertaken during the project;
- providing feedback on draft findings and analysis, as presented by the Consultant and Renew at Reference Group meetings or out of sessions directly to Renew;
- fostering an open and honest relationship with Renew and the Consultant, in a spirit of sharing experience and learnings to benefit the industry/consumers as a whole;
- strengthening the partnership and understanding between Renew, the Consultant and the Reference Group members.

The Reference Group started as a smaller group of around 20 people, but grew over the course of the project as the consultation process became more expansive. This is the full list of people who were engaged at one time or another as part of the Reference Group.

Table D1 – Reference Group List

Name	Organisation	Type
Anthony Bell	AEMC	Market/Industry Body
Christiaan Zuur	AEMC	Market/Industry Body
Ed Chan	AEMC	Market/Industry Body
Kate Wild	AEMC	Market/Industry Body
Chris Cormack	AEMO	Market/Industry Body
Chris Davies	AEMO	Market/Industry Body
Luke Barlow	AEMO	Market/Industry Body
Rama Ganguli	AEMO	Market/Industry Body
Taru Veijalainen	AEMO	Market/Industry Body
Anthony Seipolt	AER	Market/Industry Body
Con Hristodoulidis	AGL	Retailer
Greg Abramow	AGL	Retailer
Kurt Winter	AGL	Retailer
Travis Hughes	AGL	Retailer
Jordan Welsh	ARENA	Market/Industry Body
Alexandra Sidorenko	Ausgrid	Network
Justin Betlehem	Ausnet Services	Network
Justin Harding	Ausnet Services	Network
Tom Langstaff	Ausnet Services	Network
Emma Chessell	Brotherhood of St Laurence	Consumer/Community
Frans Jungerth	CitiPower/Powercor	Network

Sonja Lekovic	CitiPower/Powercor	Network
Darren Gladman	Clean Energy Council	Market/Industry Body
Andrea Espinosa	DELWP Vic	Government
Damien Moyse	DELWP Vic	Government
Katie Brown	DELWP Vic	Government
Simon McCabe	DELWP Vic	Government
Luke Reade	Energetic Communities	Consumer/Community
Elisabeth Ross	Energy Consumers Australia	Consumer/Community
Adrian Merrick	Energy Locals	Retailer
Michelle Monaghan	Energy Locals	Retailer
Peter Price	Energy Queensland	Network
Vanessa Swinson	Energy Queensland	Network
Gavin Morrison	Essential Energy	Network
Joshua Harvey	Essential Energy	Network
Therese Grace	Essential Energy	Network
Ben Hutt	Evergen	New Energy Services
Stephen Pritchard	Evergen	New Energy Services
Peter Wong	Jemena	Network
Hannah Heath	Nectr	Retailer
Andrew Lewis	Planning NSW	Government
Arianwyn Lowe	Planning NSW	Government
Michael Sherburn	Powershop	Retailer
Paul Liddell	Redback Tech	New Energy Services
Chris Marsden	SA Government	Government
James Simmonds	SA Government	Government
Rebecca Knights	SA Government	Government
Vince Duffy	SA Government	Government
Brendon Hampton	SAPN	Network
Bryn Williams	SAPN	Network
Jin Woo Kim	ShineHub	New Energy Services
Jonathon Dore	Solar Analytics	New Energy Services
Gavin Dufty	St Vincent de Paul	Consumer/Community
John Phillpotts	Strategen	Research/Analyst
Mark Paterson	Strategen	Research/Analyst
Alison Washusen	SwitchDin	New Energy Services
Andrew Mears	SwitchDin	New Energy Services
Emma Fagan	Tesla	New Energy Services
Mike Swanston	The Customer Advocate	Consumer/Community
Mark Byrne	Total Environment Centre	Consumer/Community
Greg Hannan	United Energy	Network
Sharon Tissai-Krishna	United Energy	Network
Iain Macgill	UNSW	Research/Analyst

Importantly, while the Reference Group members gave generously of their time, and Energeia considered their input and feedback carefully, the report reflects Energeia's views and not necessarily that of the Reference Group. Energeia thanks the Reference Group for their time and input over the course of the project.

D.3 Steering Group

The Steering Group was assembled by Renew to give guidance on the overall direction of the project. Members of the Steering Group also participated in consultation both as part of the Reference Group and separately.

Table D2 – Steering Group List

Name	Organisation	Type
Elisabeth Ross	Energy Consumers Australia	Consumer/Community
Mike Swanston	The Customer Advocate	Consumer/Community
Mark Byrne	Total Environment Centre	Consumer/Community
Iain Macgill	UNSW	Research/Analyst

Energeia thanks the Steering Group for their time and input over the course of the project.

D.4 Consultation Group

After the release of the draft report, Energeia and Renew requested feedback from a broad range of market stakeholders. The following table lists the organisations that provided feedback to the final report.

Table D3 – Stakeholder Consultation List

Organisation	Type
AEMO	Industry Body
AGL	Retailer
CitiPower, Powercor and United Energy	Network
Cutler Merz	Research/Analyst
Q-Cells	Research/Analyst
Solar Analytics	New Energy Services
Strategen	Research/Analyst
Total Environment Centre	Industry Body

The feedback was then categories into the three categories used to segment stakeholder feedback in the initial targeted stakeholder consultation as shown below.

Table D4 – Stakeholder Feedback by Category

Organisation	Policy and Regulation	Technical	Consumer	Other
Cutler Merz	12	12	2	3
CitiPower, Powercor and United Energy	2	1	0	2
AEMO	0	1	0	0
Strategen	19	45	0	2
Total Environment Centre	0	4	0	4
AGL	0	2	1	1
Solar Analytics	3	9	0	9
Q-Cells	1	3	0	1

Energeia addressed the feedback either by updating the report accordingly or providing a response detailing the basis of our decision to retain our existing position.

Energeia thanks the Consultation Group for their time and input over the course of the project.

Appendix E – wSim

Energeia's network[64] and generator impact analysis are based on two models, Energeia's Utility Simulation Software (uSim) and Energeia's Wholesale Market Software (wSim). This section outlines the structure and approach of Energeia's wSim and details the modelling process, modules, and key assumptions.

E.1 Overview

The following sections describe Energeia's approach to determining the model's key inputs, simulating the NEM Security-Constrained Economic Dispatch (SCED) and associated pricing of energy, ancillary services and key generator revenue streams including reliability obligations and renewable energy certificates, and forecasting capacity expansion over time.

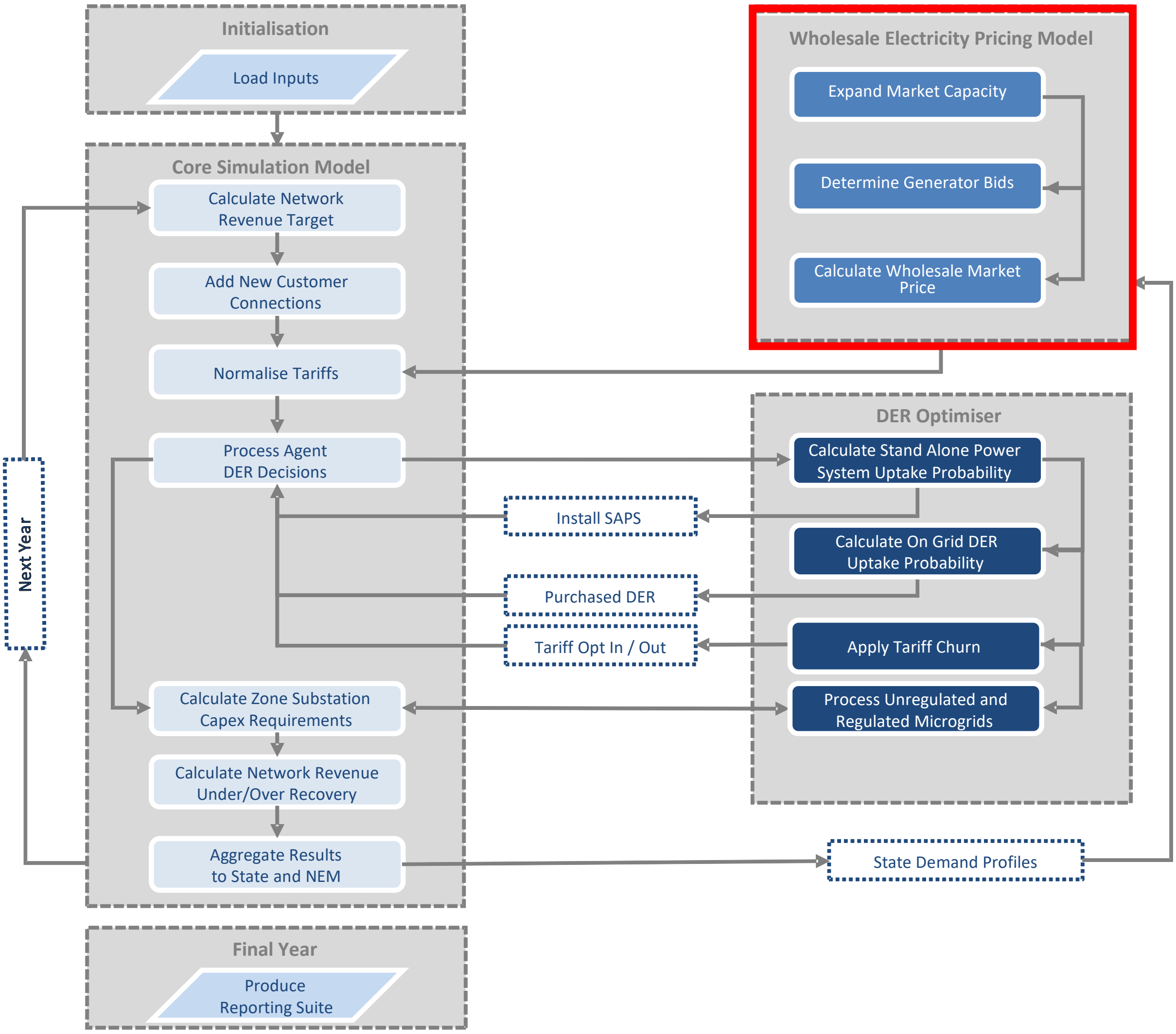
E.1.1 Structure of the Model

Energeia's wholesale market model (wSim) forms an essential part of Energeia's integrated energy system model, depicted in Figure E1.

[64] More details of the distribution network model's structure, process and key inputs are outlined in

.

Figure E1 – Overview of Energeia's Integrated Energy System Simulation Platform (wSim)



Source: Energeia

Although the wSim model can be operated separately from the DER simulation platform, the two systems can also be optionally integrated.

E.1.2 Methodology Selection

The modular nature of Energeia's simulation platform determines the nature and structure of the modelling of the wholesale market in wSim. The wSim module is designed to estimate the retail component of customer prices – both usage and export tariffs – that underpin uSim's analysis of distributed energy resources, and determine if, when and where new generation enters or exits the market. To be effective at these tasks, wSim therefore needs to generate wholesale market prices, and the revenues for generators participating in this market. To accurately model future wholesale market prices, and estimate the financial viability of current and new entrant generators, any wholesale market model needs to:

- Replicate the system operator's economic dispatch of generators
- Apply security constraints to the economic dispatch to ensure that reliability requirements are met
- Reflect real world generator behaviours
- Estimate the financial viability of incumbent and new entry generators

Energeia assessed international best practice as well as consensus approaches to modelling in Australia's National Electricity Market (NEM) before selecting our wholesale market modelling methodology.

E.1.2.1 International Best Practice

Energeia researched the international best practice in wholesale market modelling to understand the trade-off between model complexity and computational effort. Our research identified that that are three broad types of modelling methodologies:

- **Simulation** – building a bottom-up model of the energy system based on specific equations and characteristics
- **Optimisation** – solving an equation subject to a set of constraints, e.g. minimising total system cost subject to a set of constraints
- **Equilibrium** – Modelling the energy sector as part of the whole economy, balancing supply and demand

The most commonly implemented solutions combine a simulation approach for dispatch (normally a SCED approach) with an optimisation approach for entry and exist of new generation. The most common gaps that were observed across the modelling approaches considered included:

- **Time-Interval Granularity** – modelling at the day/week/month level rather than at the interval level (currently 30 minutes in the NEM, or 17,520 intervals in a single year) reduces modelling complexity, but it poorly represents the real world operation of the market
- **Consumer Behaviour** – consumer loads, both in their shape and in their size, are often modelled statically, with no allowance for dynamic changes in customer behaviour over time.
- **Transparency** – most modelling platforms are proprietary rather than open source, and the ability to peer review models is limited to review model outcomes rather than model processes or logic

E.1.2.2 Consensus NEM Approaches

A review of the major commercial firms conducting wholesale market modelling, as well as the models used by the system operator (AEMO) found that almost all of the modelling solutions in place relied on SCED for annual market settlement, with different approaches to determining changes in generation capacity each year.

AEMO uses a linear optimisation program to forecast capacity expansion on a least cost basis for both generation and transmission. In any given year, AEMO first forecasts the availability of generators on a probabilistic basis to determine security constraints and the applies different bidding models (either a short-run marginal cost or a Nash-Cournot equilibrium model) to forecast economic dispatch in each interval.

E.1.2.3 Energeia's Chosen Solution

A review of international best practice and Australian consensus approach has shown that economic dispatch models and security constraints are effectively commoditised – these approaches are industry standard, and any solution that Energeia develops need to reflect this standard. However, as shown in Table E1, Energeia's assessment of different solutions has shown that there is considerable room to add value to a wholesale market forecast by more accurately reflecting real world generator bidding behaviour and generator financial viability.

Table E1 – Methodology Selection Factors

	Replicating AEMO Economic Dispatch	**Applying Security Constraints**	**Reflecting Generator Bidding Behaviour**	**Estimating Generator Entry/Exit**
Commoditised	✓	✓		
Value Added			✓	✓

Source: Energeia

Energeia's chosen solution is based on a SCED engine, with an optimisation approach to assessing the entry and exit of new generation capacity, with additional capacity to configure:

- **Bidding Behaviour** – Bidding strategies, be they portfolio approaches, multi-mode, annual or daily optimisation, are configurable on a jurisdictional and annual basis throughout the modelling period

- **Capacity Entry/Exit** – Investment decisions are based on real world financial hurdles for the owner of each asset, rather than a least-cost system optimisation approach, tailored for each potential technology across the suite of potential solutions (new interconnection, aggregated DER bidding into the wholesale market, or curtailment of renewables).

E.1.3 Recent Model Development

Energeia initially developed its wholesale market module as part of Energy Networks Australia's National Transformation Roadmap[65], based on a simulation-based approach using short-run marginal cost (SRMC) based bidding assumptions. Energeia's results using wSim in 2017 and 2018 showed that the market was clearing at a price in excess of the theoretical market clearing price assuming SRMC based bidding behaviour[66]. Additionally, further investigations showed that bidding approaches appeared to vary by load, with different bidding behaviours seen during peak and minimum load conditions compared to other times.

This led to the refinement of our bidding model [67] to reflect real world behaviours as evidenced in their historic bidding strategies, resulting in a more realistic price and generator utilisation outcome compared to a simpler linear model that the dispatches generation capacity from cheapest to most expensive.

Energeia uses its simulation engine as core part of its capacity expansion modelling. As well as accounting for scheduled generator exit and entry, wSim uses generator profitability to determine what type of generators exit and enter the market in any given year and region. Our focus on profit maximisation rather than cost minimisation sets our approach apart from other common capacity expansion approaches.

Key developments have included the functionality to assess large scale storage in the wholesale market, including:

- large pumped hydroelectric energy storage projects, such as Snowy 2.0
- large grid-scale batteries, and
- concentrated solar power

For this project, Energeia has made the following additions/improvements to its wSim platform:

- **Dispatch Engine Enhancement** – accounting for more security constraints in dispatch, including ramping, minimum uptime/downtime periods, minimum bid capacity, maintenance scheduling and forced outages and accounting for more market constraints including ancillary services including Frequency Control Ancillary Services
- **Capacity Expansion Enhancement** – further improvement of this engine by endogenously calculated interconnector upgrades, improving grid battery optimisation, including renewable energy curtailment and enabling aggregated DER as a generator / resource

E.1.4 Recent Application

Energeia has worked with a wide range of clients to provide insight into their key business challenges and opportunities by applying our integrated wholesale market model, including:

- The effect of energy efficiency measures on wholesale market outcomes
- The effect of natural gas substitution measures on wholesale market outcomes
- The effect of DER on wholesale energy demand and pricing

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[65] Energy Networks Australia (2017) *Electricity Network Transformation Roadmap: Final Report*: https://www.energynetworks.com.au/resources/reports/electricity-network-transformation-roadmap-final-report/

[66] Energeia (2018), *Concentrated Solar Thermal Market Modelling*: https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-2-energia-modelling-report.pdf

[67] Our refined bottom-up approach to generator dispatch allows us to consider these real-world market behaviours, whilst reflecting the constraints faced by the generators in the NEM at different times of the year.

- The effect of various reliability and environmental policies on wholesale energy prices
- The impact of various government interventions on wholesale energy prices
- The potential market for new technology such as concentrated solar power at various price points
- The demand for storage, by hours of storage, over time under various policy assumptions
- The impact of renewable energy zones on wholesale energy prices

In each case, the wholesale energy market impact was fed through uSim to determine the impact on DER adoption, configuration and operation, distribution network investment and consumer bills.

E.2 Model Process and Modules

E.2.1 Process

Energeia's wSim platform involves two main processes and modules:

- **Capacity Expansion Processing** – For each modelled year, this module forecasts the entry and exit of generation into the NEM, subject to constraints
- **SCED Processing** – For each interval in each modelled year, this module forecasts the dispatch of electricity by each generating unit or resource in the NEM, subject to constraints

The modules of each process are explained in detail below.

E.2.2 Capacity Expansion Processing

Generators enter and exit the market based on their profits or their operation lifetime and subject to the satisfaction of wider market constraints, including economic, safety, security, reliability, emissions and renewable energy constraints. These are further detailed in the sections below.

E.2.2.1 Entry and Exit Process Overview

For each modelled year, wSim identifies the generators exiting the market, which is either due to sustained revenue losses or having reached the end of their operating life (the safety constraint). However, Energeia ensures that the total capacity of generators exiting the market does not exceed a given threshold inputted by the user. In these instances, generators operating with the greatest loss are removed from the market first.

Potential generators can enter and exit the market based on the following conditions:

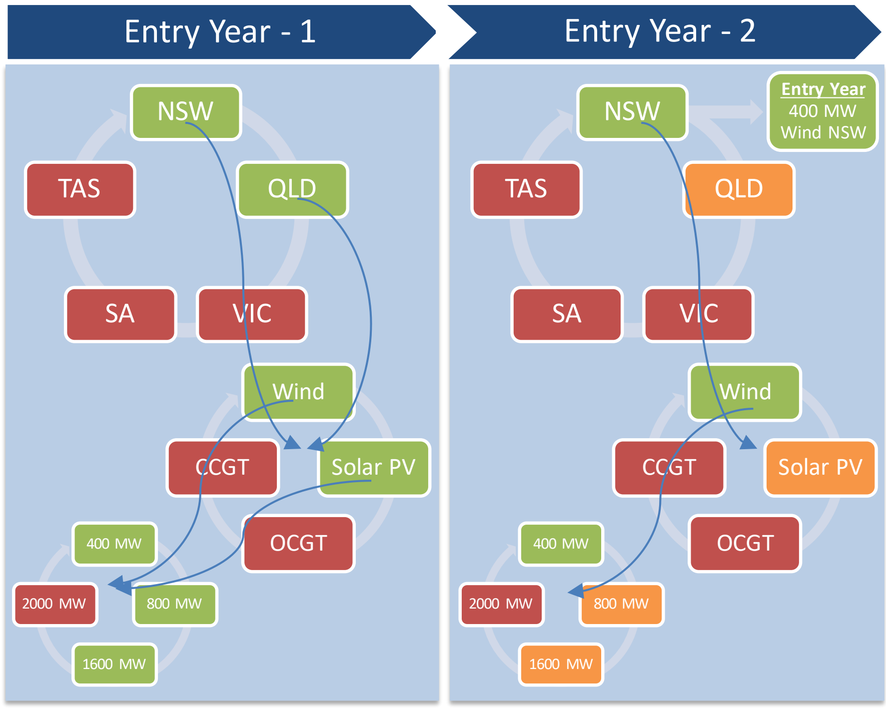
- Their calculated NPV
- User inputs to force the entry of generators, such as those currently in construction and are likely to begin operating in first few modelled years
- If a security or reliability constraint[68] is not satisfied by the end of the economically-determined capacity expansion process for the year
- To satisfy emission or renewable energy constraints[68] based on policy settings set by the user, or a subsidy for low-emission technologies can be applied to “soften” the constraint.

The model's wholesale market new entry procedure is illustrated in Figure E2, which shows that the model will iterate through a potential generator based on their location by state, their technology type and their capacity sizing[69] to assess configuration which would deliver the highest net present value (NPV).

[68] This is further detailed in the following sections

[69] All available states, technology types and capacity sizing available to be assessed is subject to the user

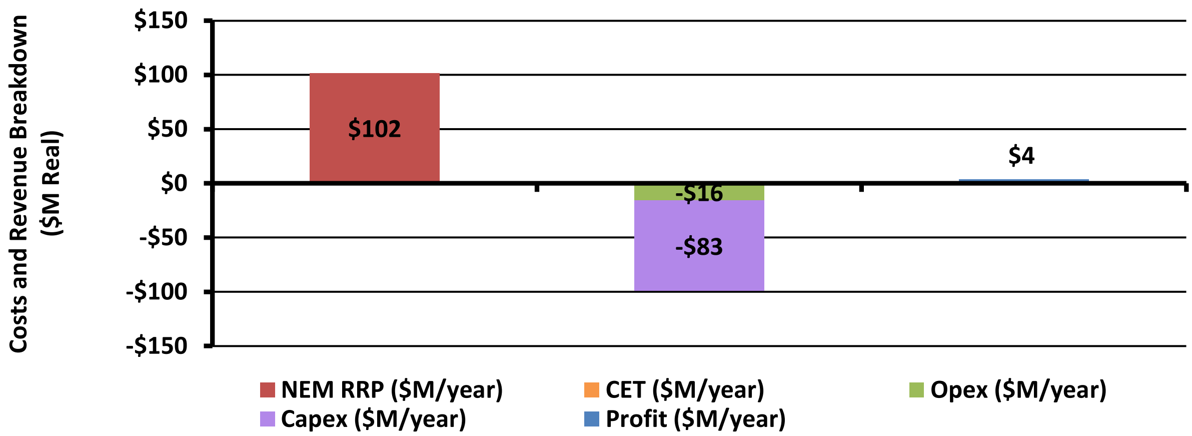
Figure E2 – Illustration of Wholesale Market Model Operating Procedure (Indicative)



Source: Energeia; Note: Colours represent the level of net present value for the generator configuration, where green is the highest and red is the lowest.

Generators enter the market based on their calculated NPV and an optimised fuel and capacity size. These calculations are determined through estimating forward-looking dispatch and profits in the simulated year, including spot price revenues, renewable energy certificates and carbon mechanism scheme payments (if any), fuel and variable operational and maintenance costs and capital charges as shown in Figure E3.

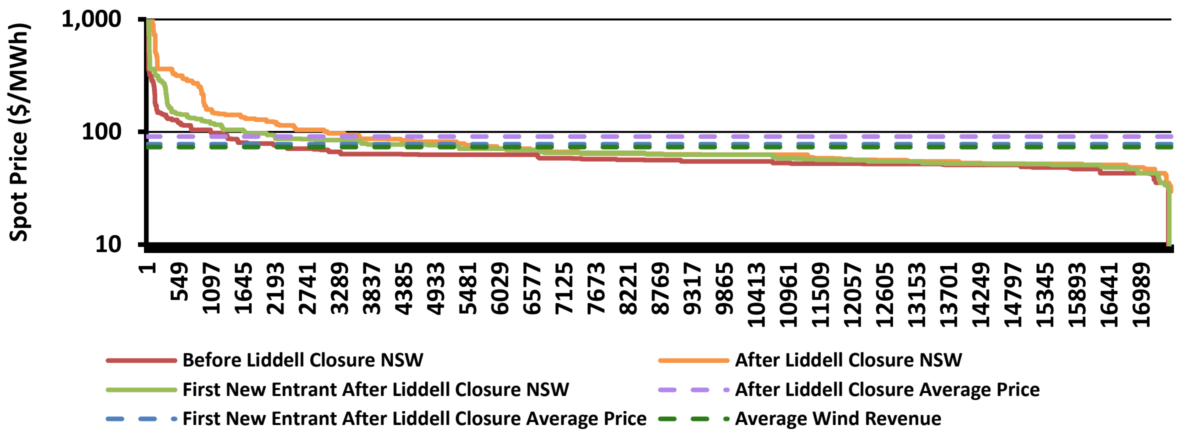
Figure E3 – Illustration of Key Costs and Benefits in a Project's NPV Calculation (Indicative)



Source: Energeia

The NPV calculation also considers the effect of the new project on market prices using the model's generator bidding and dispatch algorithms which estimates the merit order. Where the project displaces the marginal unit, it reduces the market clearing price. This typically tempers project sizing, as larger projects are more likely to displace the marginal generator. For example, Figure E4 illustrates how the merit order impact calculations affect the merit order and market pricing before and after Liddell closes, and before and after the first new entrant project.

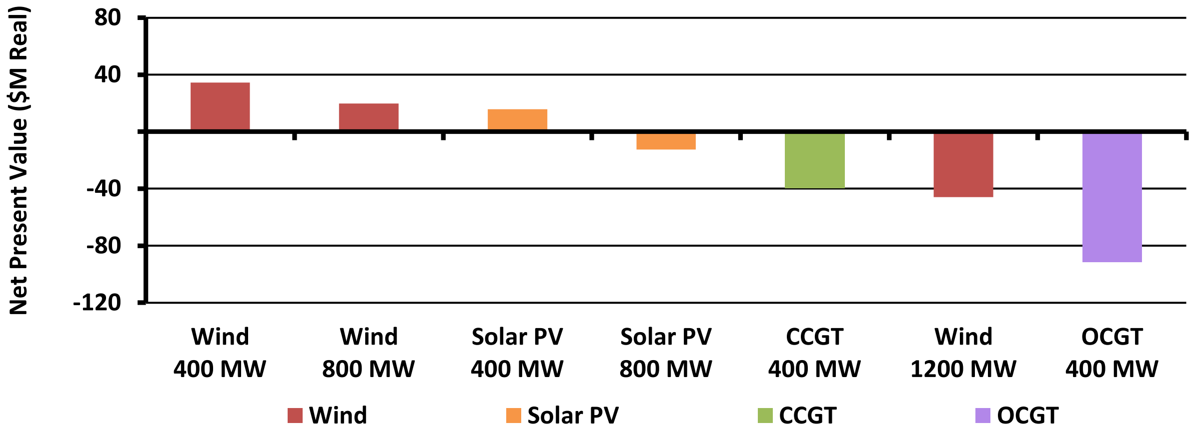
Figure E4 – Illustration of Merit Order Impact Calculations



Source: Energeia

Generators potentially entering the market are ranked, where generators with the highest calculated NPV enter into the market first until a threshold capacity of generation entry is reached, or all new entrants calculate a negative NPV from entry. This ranking system is illustrated in Figure E5 showing a 400 MW wind project as the project delivering the best financial outcome out of an array of potential open cycle gas turbines (OCGT), close cycle gas turbines (CCGT), wind, large-scale solar PV, concentred solar thermal (CST), large-scale lithium storage systems, pumped hydroelectric energy storage (PHES) and demand side DER aggregation projects.

Figure E5 – Illustration of NPV Ranking between Projects (Indicative)



Source: Energeia

E.2.2.2 Summary of Constraints

Energeia has applied the following constraints which impact the generator exit and entry process:

- **Economic Constraint** – This refers to determining generator entry or exit by profitability. Generators must show a positive NPV for two years in a row before deciding to enter and must record operating losses for two consecutive years before exiting the market. This is a configurable setting that acts as a ballast against gyrating wholesale prices due to generator entry and exit activity.
- **Safety Constraint** – This refers to generators exiting the market when they have reached their "end of life". Their capacity in the market is lost and may be replaced if it results in one of the other constraints not being satisfied.
- **Security Constraint** – This refers to the ability of market supply to meet demand in a single credible contingency event, such as an outage to the largest generator in each region (largest n-1 test) during peak demand. If this constraint is not satisfied, the model will force the entry of the lowest-cost generation in that region until it is no longer an issue.

- **Reliability Constraint** – This refers to the ability of firm capacity to meet peak demand. Firm capacity refers to generation that can be plausibly relied upon to deliver during the peak demand of each region. This includes only scheduled and semi-scheduled generation (> 30 MW), and discounts variable renewable energy capacity. If this constraint is not satisfied, the model will force the entry of the lowest cost firm generation in that region until it is no longer an issue.
- **Emissions Constraint** – This refers to the maximum carbon emissions the energy market is allowed to produce in a calendar year. It is a configurable setting intended to simulate environmental policy outcomes. If this constraint is not satisfied, wSim will force the exit of carbon-emitting technologies in favour of the lowest cost low/zero emissions technologies until carbon emissions levels are below the permissible level.
- **Renewable Energy Constraint –** This refers to the minimum requirements for demand met by renewable energy in the market. Similar to the emissions constraint, it is a configurable setting intended to simulate environmental policy outcomes. If this constraint is not satisfied, wSim will force the exit of non-renewable technologies in favour of the lowest cost renewable generation until the minimum % of electricity demand is met by renewable energy.

E.2.3 SCED Processing

wSim takes aggregated demand profiles and determines the bid stack of generation required to satisfy demand at each interval, subject to generation and transmission constraints, as well as any additional generation required for ancillary services where applicable. The following sections detail the following processes and constraints:

- Demand process
- Generator bidding and merit ordering process
- Generator constraints
- Transmission constraints
- Ancillary services process

E.2.3.1 Demand Process

Aggregate annual demand profiles for each state, with 30-minute frequency, are provided to the wSim model from uSim. These demand profiles include the impact of DER as customer demand prioritises behind-the-meter generation, which is an accurate reflection of reality.

E.2.3.2 Generator Bidding and Merit Ordering Process

Generator bidding is primarily based on the short-run marginal cost (SRMC) of the generator including the cost of carbon emissions by the generator.

As is the case in the actual NEM wholesale market, each generator has up to ten bids[70] they can submit for each eligible interconnector that it can access[71], representing "bands"[72] of each generator's determined bidding behaviour. For those generators without historical bidding data, there are generic inputs available for each fuel and state combination.

The value of a bid is a function of the generator's SRMC, a step-up dollar factor that is unique to each fuel type, and a step-up percentage factor that is unique to each fuel type. The step-up factors increase for each bid the generator has, with the tenth bid, or the last bid, being the highest.

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[70] These bids are characterised by an amount of energy (expressed as a % of capacity per interval) and a price. These are set as inputs to the model

[71] Intra-state energy sales are modelled with a virtual interconnector having infinite capacity

[72] 10th, 20th, 30th, etc. percentile

$$Bid_{gen,i=1...10} = \left(SRMC_{gen} + DollarFactor_{i,fuel}\right) * \left(1 + PercentFactor_{i,fuel}\right)$$

There are two exceptions to this bidding formula. Coal generators will always bid their minimum operating capacity at the market floor. This is their first bid and the remaining nine bids are for the remaining capacity. Non-dispatchable renewables will bid their entire capacity at zero dollars as they do not have the ability to control dispatch and have no SRMC. Note that this is configurable by the user.

For each interval, wSim determines which bid set applies, then dispatches each bid in order until state demand is met or all bids are exhausted, calculating effects of losses in real-time and skipping bids that cannot be dispatched due to generator unit capacity or transmission constraints. Energeia's bidding approaches is benchmarked against actual generator bidding behaviour by fuel and technology type as shown in Figure E6.

Storage technologies operate differently to generators. Grid batteries optimally charge and discharge once the bidding process has been completed. Grid batteries take the calculated wholesale price at each interval and aim to maximise their profits on a defined periodic basis by importing and exporting to the NEM based on a charging algorithm. After storage technology profiles have been generated, the bidding process is re-run to deliver the final generation outcomes for the modelled year.

Energeia notes that a key limitation of the generation bidding process is that bids are static not dynamic, in opposition to the real-life situation.

Figure E6 – Comparing Bidding Model to Actual Bidding Outcomes by Fuel and Technology

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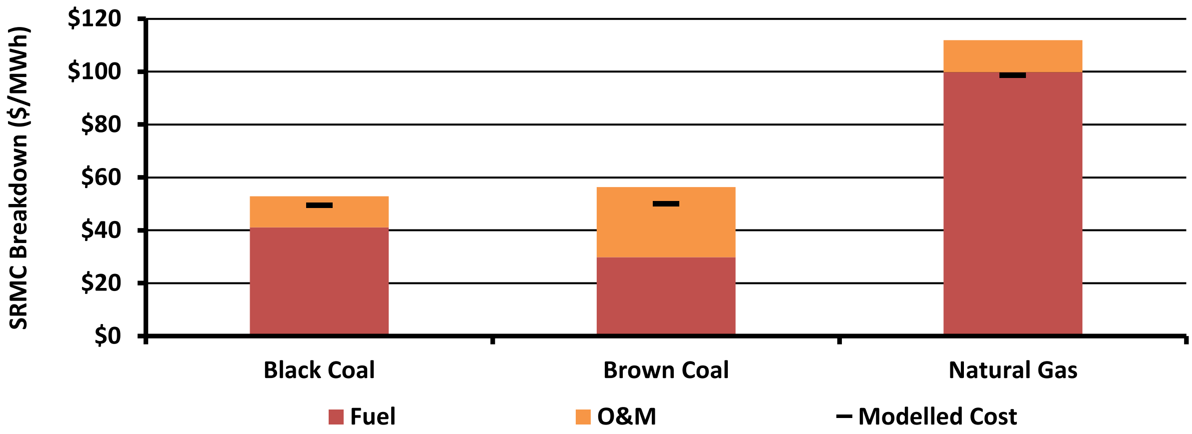

Source: Energeia

E.2.3.3 Generator Constraints

In addition to bidding strategies, wSim also considers some additional constraints on generation which reflect reality and will affect the profitability of generators. They are defined by each type of generation and include:

- **Ramping** – The maximum rate at which a generator can increase and decrease capacity exported per interval
- **Minimum Uptime and Downtime Periods** – If a generator start or stops dispatching in an interval, it must continue generating or not generating for a specified number of intervals following, even if that generation does not dispatch to the grid
- **Minimum Capacity** – The lowest amount of generation capacity that can be produced, as a % of maximum usable capacity, even if it does not all get dispatched to the grid
- **Fixed Generation** – Generators with variable generation profiles will be able to bid according to a fixed profile. For example, a solar PV generator will not be able to bid during intervals with no solar irradiance
- **Maintenance** – Some downtime is allocated to each generator in the year to undergo scheduled maintenance

- **Forced Outages** – The outage rates of each generator are accounted for in their potential maximum usable capacity.

The generator constraints generally favour generation that is more reliable and flexible when determining profitability.

E.2.3.4 Transmission Constraints

Interconnectors connect the transmission networks in each NEM state with each other. The wSim model utilises interconnectors to lower prices across the interconnected network by allowing energy to flow from high price states to low price states. In the model, interconnectors have two capacity ratings (one for each direction) and a loss factor.

Interconnector capacity is able to evolve each modelled year exogenously through AEMO's ISP schedule for transmission upgrades. This has a significant impact on the dispatchability of generation and the potential to satisfy security constraints. Energeia has flagged the calculation of interconnector upgrades as a future improvement for the model.

E.2.3.5 Ancillary Services Process

In addition to dispatching electricity in the wholesale market, generators are also able to participate in ancillary service markets that contribute to market reliability, including for ramping, regulation, and contingency services. For each interval modelled, wSim calculates ancillary demand, and generator bidding to determine the price received per MWh for the service. Note that bidding into the wholesale market is always prioritised over the provision of ancillary services.

Effectively, by accounting for ancillary services, wSim favours new generation technologies with a high level dispatchability (i.e. the ability to ramp up/down quickly), which is likely to reflect the future energy needs of the NEM.

E.3 Inputs and Assumptions

Energeia builds a database of all existing generators in the NEM as listed in AEMO's latest NEM Generation Information publication[73]. Energeia then uses a variety of sources to determine the key characteristics of existing generators that are necessary for wSim.

Energeia takes forward those characteristics to determine the key information for new potential generation and transmission in the NEM, for consideration in the capacity expansion process.

E.3.1 Generation

Energeia's key assumptions for generation assets includes the following:

- **Operation and Maintenance Costs** – Energeia researches the fixed operational costs by generator type, which count towards the NPV calculations each year. For simplicity, Energeia assumes there are no variable operation and maintenance costs of generation.
- **Heat Rates** – Heat rates affect the maximum output capacity of a generator. Energeia uses research to determine heat rates, which are assumed to vary by generator type and do not change over time.
- **Fuel Prices** – Energeia researches the latest relevant fuel price forecasts from a variety of sources which vary by generation technology. Fuel prices are assumed not to vary by region, and renewable generation is assumed to have no fuel cost.

[73] Available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

- **Summer and Winter Rating** – As weather factors affects the efficiency of energy production, Energeia assumes differing summer and winter capacities for thermal and storage and wind technologies, as determined through research.
- **Age and Lifetime** – The age of each existing generator is provided by AEMO in their NEM Generation Information, which also provides the expected year of exit. If the exit year is not provided, Energeia assumes that a generator unit has a useful life of 50 years, after which it will be decommissioned.
- **Minimum Loading** – Energeia uses research and analysis to determine the minimum capacity that a resource can generate at. This is assumed to vary by technology.
- **Ramp Rates** – Energeia uses research and analysis to determine the maximum ramp rates at which generation can increase or decrease over a single interval. This is assumed to vary by technology.
- **Outages and Maintenance** – Energeia researches the % of time a generator is likely to spend down in a year, either through unplanned or planned outages, which is assumed to vary by technology.
- **Generation Profiles** – For solar PV, wind and hydro generation, Energeia researches and processes the calendar year output profiles as a % of maximum usable capacity at any given interval. The profiles are assumed to vary by region and technology type, but do not change by year.
- **Capital Costs** – For new technology types only, the $/kW or $/kWh capital cost for designing, installing, and commissioning is forecasted on an annual basis based on research and analysis of current costs and learning rates, and varies by technology type. The capital cost affects the NPV calculation that determines if, when and where a new generator enters the market.
- **Minimum Build-Out** – Energeia assumes that all technologies must be built at a minimum capacity with additional incremental capacity available, both of which are user-defined inputs.

E.3.2 Transmission

Energeia's key assumptions for transmission assets includes the following:

- **Losses** – As ambient temperature affects the efficiency at which transmission lines can transport energy, Energeia assumes a different marginal loss factor for summer and winter for each interconnector. Energeia also makes the simplifying assumption that intrastate transmission has no losses in energy.
- **Age and Lifetime** – Energeia makes the simplifying assumption that interconnectors have an infinite asset life, and hence do not need replacing. They can only be upgraded.
- **Capital Cost** – For interconnector upgrades considered, Energeia analyses DNSP RIT-Ts and the AEMO ISP to estimate the current $/kVA capital cost of transmission in the NEM. Forecasts of capital costs are developed based on the current capital cost with a learning rate applied.
- **Minimum Build-Out** – Energeia assumes that all interconnector upgrades must be built at a minimum capacity with additional incremental capacity available, both of which are user-defined inputs.

Appendix F – About Energeia

Energeia was founded in 2009 and has grown to become one of the largest specialist energy consultancy in Australia. Energeia specialises in providing advisory and technical services in the following areas:

- Energy policy and regulation
- Smart networks and smart metering
- Energy storage
- Electric vehicles and charging infrastructure
- Distributed generation and storage technologies
- Network planning and design
- Demand management and energy efficiency
- Energy product development and pricing
- Wholesale and retail electricity markets

Energeia delivers its services across three lines of business:

- **Proprietary Research** – We provide in-depth reports on Distributed Energy Resources (DER) related markets and technologies of strategic interest, including electric vehicles, solar PV and storage, smart grids, microgrids, energy efficiency and home energy management.
- **uSim and wSim Utility and Market Simulators** – We have developed industry leading utility simulation software that models customer behaviour, bills, DER adoption, 17,520 load profiles, utility sales, capex, opex, rates and financial performance, on an integrated basis.
- **Professional Services –** We offer tailored services in the areas of rate and incentive design, cost of service analysis, DER and load forecasting, system planning, and DER technology related strategy and plan development.

We are organised into research, consulting and software development functional units, but there is significant cross-over between the working groups due to the significant quantitative analysis that we perform on behalf of our clients, much of which requires custom tooling.

- The software development working group is responsible for the development of our utility simulation tool, uSim.
- The consulting and research team are responsible for delivering Energeia's proprietary research reports and professional services.

Energeia's mission is to empower our clients by providing evidence-based advice using the best analytical tools and information available

Heritage

Energeia was founded in 2009 to pursue a gap foreseen in the professional services market for specialist information, skills and expertise that would be required for the industry's transformation over the coming years.

Since then the market has responded strongly to our unique philosophy and value proposition, geared towards those at the forefront and cutting edge of the energy sector.

Energeia has been working on landmark projects focused on emerging opportunities and solving complex issues transforming the industry to manage the overall impact.

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