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Long-Run Marginal Cost – Final Report

Prepared by ENERGEIA for
Power and Water Corporation

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ENERGEIA

Executive Summary

The National Electricity Law and Northern Territory Electricity Rules (NEL and NT NER) require Power and Water Corporation (PWC) to set network tariffs based on the Long-Run Marginal Cost (LRMC) of providing distribution services during the period of greatest utilisation for direct control services.[1] The method used to calculate, implement and apply LRMC must have regard for its associated costs and benefits.[2] Finally, the NT NER requires that the Australian Energy Regulator (AER) accept these forecasts if they reasonably reflect a realistic expectation of LRMC.[3]

Scope and Approach

PWC engaged Energeia to develop LRMC estimates by voltage level that would be fit-for-purpose and accepted by the AER, to be factored into the tariff rates contained in its Tariff Structure Statement (TSS).

Energeia worked closely with PWC to develop and deliver the following scope and approach for this project:

1. **Document Requirements** – Energeia reviewed the regulatory framework, recent determinations and engaged with subject matter experts (SMEs) and stakeholders from PWC to define the key requirements.
2. **Identify Current Industry Practices –** Energeia benchmarked peer Distribution Network Service Provider (DNSP) forecasting methodologies and AER feedback from recent regulatory cycles to identify industry standard practices.
3. **Develop Methodology** – Based on the outcomes from step 1 and 2, Energeia developed a best practice, fit-for-purpose and NT NER compliant procedure for producing LRMC estimates.
4. **Data Gathering and Processing** – Energeia gathered and processed the most recent inputs from PWC for use in the forecasting methodology.
5. **Develop LRMC** – Energeia implemented the methodology determined above to develop LRMC estimates for PWC's 2024-29 regulatory period.
6. **Consultation and Validation** – Energeia worked closely with PWC stakeholders and SMEs to validate the methodology, inputs, and outputs of the LRMC calculation process.
7. **Documentation** – Energeia documented the process, methodology and key inputs used to produce the LRMC estimates in this report.

Industry Practice

Energeia reviewed documents from the AER, the Australian Energy Market Operator (AEMO) and DNSPs to identify industry benchmarks and best practice LRMC estimation methodologies, including the Average Incremental Cost (AIC) method, the Turvey method, and the Long Run Incremental Cost (LRIC) method. This was completed to ensure that the LRMC estimation methodology selected for this project reflected the lowest net costs for PWC, as the benefits from more costly, sophisticated LRMC methodology were limited for the majority of PWC's customers due to not being exposed to LRMC price signals as a result of the NT Pricing Order.

Energeia's research found that most of the industry used the AIC method, with Victorian DNSPs using a very similar Marginal Incremental Cost (MIC) method and Queensland DNSPs using the LRIC method.

[1] Section 6.18.5.(f)(2) of the NT NER (Version 96)

[2] Section 6.18.5.(f)(1) of the NT NER (Version 96)

[3] Ibid. 6.18.8.(a)(3)

Methodology

The methodology that Energeia developed and implemented utilised the AIC method for calculating LRMCs by voltage level. The development process consisted of the following key steps:

1. **Develop Long-Run Marginal Cost Procedure –** Energeia first developed a fit-for-purpose LRMC calculation procedure that satisfied PWC's key requirements and reflected industry standard practice.
2. **Data Gathering and Processing –** This step included gathering the key inputs for the calculation, including capital expenditure (capex), comprised of replacement expenditure (repex) and augmentation expenditure (augex), operational expenditure (opex), demand, and allocations by voltage level[4]. Other key inputs included Weighted Average Cost of Capital (WACC), power factors, Distribution Loss Factor (DLFs), calculation time horizon, and extending costs and demand beyond the 2024-29 regulatory control period.
3. **Average Incremental Cost Calculation –** In this step, Energeia calculated incremental demand and costs across the PWC network, to feed into the AIC calculation for the final LRMC estimate by voltage level.
4. **Validate Optimised Results –** Energeia compared the calculated LRMC value with PWC's previous LRMC, and also compared them to other DNSPs' LRMCs. Additionally, Energeia consulted with PWC stakeholders prior to finalisation.

A detailed discussion of the above steps and key inputs is presented in Section 3.

Results

Energeia's estimate of PWC's LRMC by voltage level is given in Table ES1, which applies to imports and exports.

The NT NER defines the long run as the period of time in which all factors of production required to provide direct control services can be varied[5]. In Energeia's view, this definition requires LRMC to reflect all forecast operating and capital costs, including repex, over a 50-year period or longer. However, the NT NER also requires[6] that the customer impact of tariff changes be considered, and that tariffs may vary from efficient levels during a transition period to manage these impacts.

[4] Voltage levels included Sub-transmission (ST), High Voltage (HV) and Low Voltage (LV)

[5] Ibid. Glossary

[6] Ibid. 6.18.5.(h)(1)

Table ES1 – Calculated LRMC by Voltage Level

Voltage Level	$/kVA/year
ST (Total)	**41.76**
Augex	8.23
Opex	14.52
Repex	19.01
HV (Total)	**103.95**
Augex	31.21
Opex	36.14
Repex	36.59
LV (Total)	**164.90**
Augex	24.91
Opex	57.34
Repex	82.65

Source: Energeia

The resulting LRMC estimates were found to be similar to historical estimates from PWC, and similar to Ergon Energy's LRMC (based on Long-Run-Incremental-Cost) as a noted comparable network. Further detail regarding these estimates, including a comparison with other DNSPs' LRMCs can be found in Section 4.

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Disclaimer

While all due care has been taken in the preparation of this report, in reaching its conclusions Energeia has relied upon information and guidance from Power and Water Corporation, and other publicly available information. To the extent these reliances have been made, Energeia does not guarantee nor warrant the accuracy of this report. Furthermore, neither Energeia nor its Directors or employees will accept liability for any losses related to this report arising from these reliances. While this report may be made available to the public, no third party, with the exception of the Australian Energy Regulator, should use or rely on the report for any purpose.

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1. Background

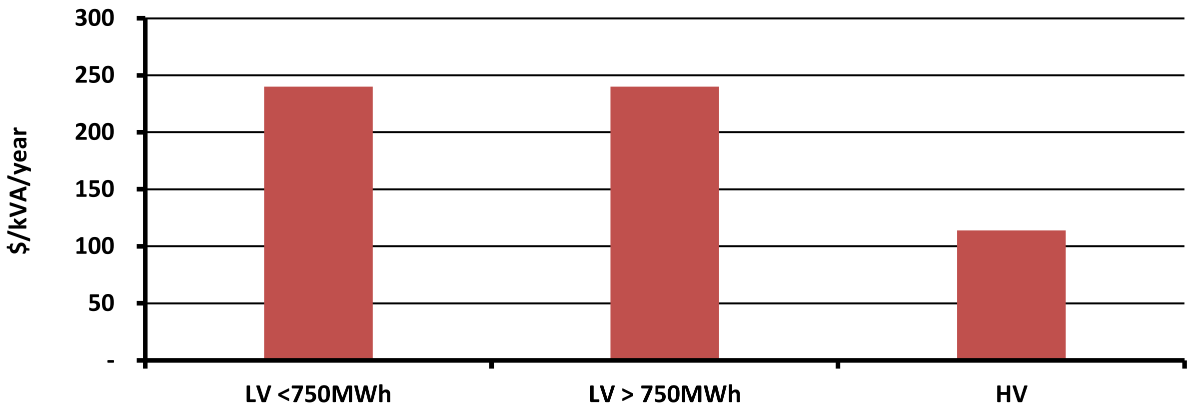
The National Electricity Law and Northern Territory National Electricity Rules (NEL and NT NER) require Power and Water Corporation (PWC) to set network tariffs based on the Long-Run Marginal Cost (LRMC) of providing distribution services during the period of greatest utilisation for direct control services.[7] The method used to calculate, implement and apply LRMC must have regard for its associated costs and benefits.[8] Finally, the NT NER requires that the Australian Energy Regulator (AER) accept these forecasts if they reasonably reflect a realistic expectation of LRMC.[9]

This section details the key regulatory and business requirements for producing fit-for-purpose LRMC forecasts including a summary of Australian Distribution Network Service Provider (DNSP) methodologies.

1.1. *Current Long-Run Marginal Cost*

Figure 1 shows PWC's current LRMC values for the 2019-24 regulatory period. They are the same for LV classes, and lower for HV classes, due in part to less infrastructure needed to serve HV customers.

Figure 1 – LRMC Estimated for Regulatory Period 2019-24



Source: PWC TSS

Energeia notes that PWC's current LRMC calculations are in line with Ergon Energy's at the time, which is a comparable regional distribution network.

1.2. *Key Regulatory Requirements*

PWC's LRMC forecasts are regulated under Section 6.18.5 of the NT NER, which governs the costs to be included, the period over which to estimate them, the method for calculating them and the basis for varying from them.

[7] National Electricity Rules as In Force in the Northern Territory Version 96 Section 6.18.5.(f)(2)

[8] Ibid. 6.18.5.(f)(1)

[9] Ibid. 6.18.8.(a)(3)

1.2.1. Pricing

LRMC forecasts are used to develop customer tariffs in PWC's Tariff Structure Statement (TSS), which forms part of the Initial Regulatory Proposal (IRP). Regarding their calculation, implementation and application, the NT NER state in Section 6.18.5[10] that:

> *(f) Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:*
>
> > *(1) the costs and benefits associated with calculating, implementing and applying that method as proposed;*
> >
> > *(2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant service; and*
> >
> > *(3) the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.*

The definition of long run marginal cost in the NT NER Glossary[11] sets out the scope of costs to be included and how they should be factored in:

> *For the purposes of clause 6.18.5, 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.*

In Energeia's view, this definition requires LRMC to reflect all forecast operating and capital costs, including repex. However, the NT NER also requires[12] that the customer impact of tariff changes be considered, and that tariffs may vary from efficient levels during a transition period to manage these impacts.

> *(h) A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to:*
>
> > *(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);*
> >
> > *(2) the extent to which retail customers can choose the tariff to which they are assigned; and*
> >
> > *(3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.*

A transitional pathway may therefore be used under the NT NER where desirable[13] to manage the impact of moving prices towards full compliance with the Pricing Principles. In this situation, the desirability of efficient price signalling is balanced the desirability of managing customer bill impacts[14].

Export Pricing

In 2021, the AEMC amended the Northern Territory National Electricity Rules (NT NER) to allow more efficient integration of distributed energy resources (DER) into the electricity grid. The rule change allowed for the addition

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[10] National Electricity Rules as In Force in the Northern Territory Version 96 Section 6.18.5(g)(1)

[11] Ibid. Glossary

[12] Ibid. 6.18.5.(h)(1)

[13] Energeia notes that desirability is not defined in the NT NER, so Energeia assumes its common meaning.

[14] The Pricing Order means that a portion of LV customers (< 750 MWh) are not yet exposed, but they could be in future.

and design of export tariffs for retail customers[15]. Under the Export Tariff Guidelines[16], the AER outlines an LRMC calculation for an export tariff to align to the principles outlines above in Section 6.18.5 of the pricing principles. Under this, export LRMC should be calculated under the time period where the network experiences the greatest utilisation export in the distribution network.

1.2.2. Reset RIN

The Australian Energy Regulator (AER) collects information from DNSPs through Regulatory Information Notices (RINs) during regulatory determinations and for performance reporting. Section 28D of the NEL[17] states:

> *A regulatory information notice is a notice prepared and served by the AER in accordance with this Division that requires the regulated network service provider, or a related provider, named in the notice to do either or both of the following:*
>
> > *(a) provide to the AER the information specified in the notice;*
> >
> > *(b) prepare, maintain or keep information specified in the notice in a manner and form specified in the notice.*

Section 7.7 of the Reset RIN requires the provision of LRMC related information, including forecast capex, opex and demand.[18] Energeia notes that the RIN requests twenty years of information, which is a much shorter timeframe than the period over which all factors of production are variable[19], as specified in the NT NER Glossary.

Energeia includes all system[20] capex and opex as being consistent with the NT NER definition.

1.2.3. Standalone and Avoidable Costs

The NT NER outlines the economic efficient cost recovery bounds to be maintained when developing network tariffs. Regarding the avoidable and standalone cost, the NT NER state in Section 6.18.5[21] that:

> *…*
>
> *(e) For each tariff class, the revenue expected to be recovered must lie on or between:*
>
> 1. *an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and*
> 2. *a lower bound representing the avoidable cost of not serving those retail customers.*

[15] National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021 No. 9

[16] AER, *Export Tariff Guidelines,* 2022. https://www.aer.gov.au/system/files/AER%20-%20Export%20Tariff%20Guidelines%20-%20May%202022_0.pdf

[17] National Electricity (South Australia) Act 1996, Section 28D

[18] PWC, 2024-29 Reset RIN Workbook 1 Forecast data

[19] Distribution network assets are long-lived, with lifetimes of more than 50 years commonly assumed for major asset classes.

[20] Energeia notes that overheads and non-system costs should also be included under the NT NER definition.

[21] National Electricity Rules as In Force in the Northern Territory Version 96 Section 6.18.5e (1,2)

Energeia interprets these NT NER sections as defining compliance boundaries that:

- recover a minimum revenue, below which would result in a loss incurred by the network provider, defined as the (long-run) avoidable cost; and
- recover a maximum revenue that does not exceed the full costs a customer would incur without the network, e.g. via microgrid, defined as the standalone cost.

Calculation of standalone and avoidable cost are outlined in Appendix B – Avoidable Cost and Appendix C – Standalone Cost.

1.3. AER Feedback from Last Determination

In PWC's 2019-24 regulatory proposal, the AER accepted the AIC method utilised by PWC. However, the AER provided the following feedback for PWC, which was considered by Energeia when developing LRMC estimates for the upcoming 2024-29 regulatory period.

> *…*
>
> *We expect Power and Water to continue investigating and refining the methods for estimating LRMC for the next regulatory control period. As in the first round of tariff structure statement for distributors in the NEM, we encourage Power and Water to explore improvements to its LRMC estimation method including:*
>
> - *greater consideration to the way replacement expenditure is incorporated into its LRMC calculations*
> - *investigation of more sophisticated estimation methods, such as the Turvey approach (having regard to the costs and benefits of adopting such methods)*

Energeia's consideration of the AER's feedback is demonstrated in the following sections, which detail our consideration of more sophisticated methods and repex.

1.4. Summary of Key LRMC Methodologies

The following indicates a summary of the NT NER complaint methods utilised to develop a LRMC estimate.

The **Average Incremental Cost (AIC)**[22] approach is an estimation of future operating costs using:

- Future demand
- Capex and opex to meet future demand in present value terms

$$LRMC\ (Avg\ Incremental\ Cost) = \frac{PV(network\ marginal\ capex\ and\ opex)}{PV(\ additional\ demand\ served)}$$

It is the easiest and lowest cost approach to implement, but it is based on average incremental costs and not marginal costs, and is therefore not as efficient as Turvey or LRIC.

The **Marginal Incremental Cost (MIC)**[23] **[24]** approach is an estimation of incremental costs through the addition of an incremental value of demand using:

- Initial and revised demand
- Initial and revised capex and opex

[22] NERA Economic Consulting for the AEMC (2014), https://www.aemc.gov.au/sites/default/files/content/f2475394-d9f6-497d-b5f0-8d59dabf5e1c/NERA-Economic-Consulting-%E2%80%93-Network-pricing-report.PDF

[23] NERA Economic Consulting for the AEMC (2014), https://www.aemc.gov.au/sites/default/files/content/f2475394-d9f6-497d-b5f0-8d59dabf5e1c/NERA-Economic-Consulting-%E2%80%93-Network-pricing-report.PDF

[24] PAL ATT025 - ENEA - Long run marginal cost report - Mar2019 - Public

$$LRMC\ (MIC) = \frac{PV(marginal\ capex)}{PV(marginal\ incremental\ demand)}$$

This approach is similar to the AIC approach, but relies on specific project analysis rather than overall program analysis. The above formula does not include opex, or all costs related to meeting demand over the long-term.

The **Turvey/Perturbation**[25] approach is an estimation of incremental costs through the addition of an incremental value of demand using:

- Initial and incremental demand
- Initial and incremental capex and opex

$$LRMC\ (Turvey) = \frac{PV(incremental - initial\ capex\ and\ opex)}{PV(\ incremental - initial\ demand)}$$

This approach is more accurate but more costly than the AIC approach, as it requires a model capable of estimating marginal cost for a given unit of incremental demand over the long-run. The **Long Run Incremental Cost (LRIC)** Model / 500 MW Model[26] approach is similar in nature to the Turvey approach with the increment based on a hypothetical optimised 500 MW coincident peak demand network using:

- Building blocks for modelled representative network
- Optimised replacement cost of building block assets
- Voltage levels for LRMC estimates

$$LRMC\ (LRIC) = \frac{PV(optimised\ replacement\ cost)}{(\ voltage\ level)}$$

The cost of implementing this methodology depends on the approach, with the use of unit prices for all assets, for example from the Repex model, being lower cost than developing estimates of a marginal 500 MW load connect to a specific point of the network over time.

In summary, Energeia's view is that while the calculation methodology impacts on the accuracy of the LRMC estimate, the assumed scope of costs included is potentially a more significant decision. More accurately calculating the wrong set of costs can be less helpful than less accurately calculating the right set of costs.

The key challenge across all methods is calculating costs over the long-run, which is the period over which all costs are variable, which is over 50 years for DNSPs.

The following section outlines the methods that have been most recently utilised by DNSPs in practice.

1.5. Industry Practice

Energeia benchmarked the methods used by current NEM DNSPs to identify industry best practice and inform the configuration of our LRMC model given PWC's circumstances. Table 1 below summarises the methods utilised by DNSPs to calculate peak LRMC.

The most frequently implemented method is AIC due to its low cost and complexity. Energeia was unable to identify any quantified estimates of the costs and benefits of selecting the AIC over more accurate but higher cost methodologies, including those approved by the AER. Energeia therefore concluded that the AER does not consider, *prima facie*, other LRMC calculation approaches to be justifiable under the NER.

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[25] NERA Economic Consulting for the AEMC (2014), https://www.aemc.gov.au/sites/default/files/content/f2475394-d9f6-497d-b5f0-8d59dabf5e1c/NERA-Economic-Consulting-%E2%80%93-Network-pricing-report.PDF

[26] Ergon Energy TT Explanatory Notes 2020 – 2025, 2019, https://www.aer.gov.au/system/files/Ergon%20Energy%20-%20Revised%20Proposal%20-%2010.005%20-%20TSS%20Explanatory%20Notes%20-%20December%202019.pdf

Table 1 – Methods Implemented by DNSPs

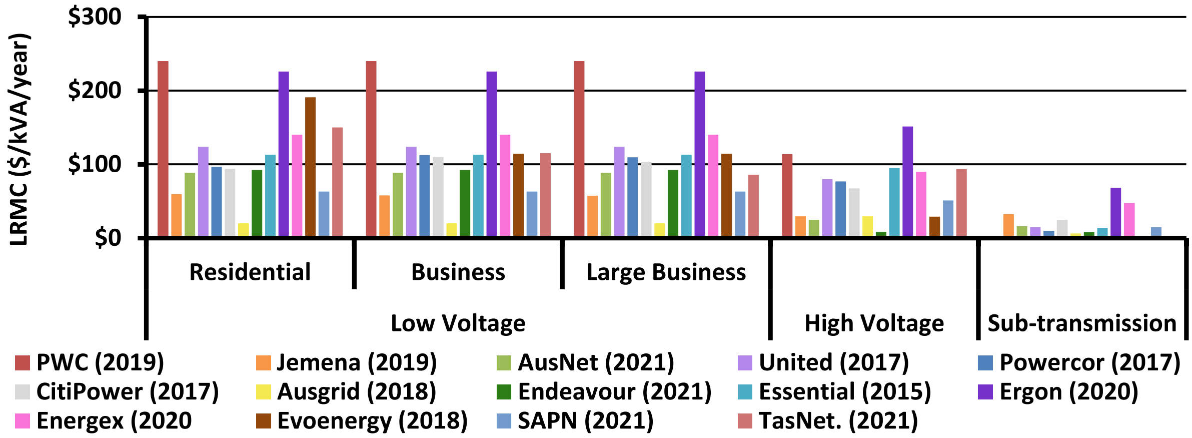
State	Network	Implemented Peak LRMC Methodology
VIC	AusNet	AIC
	Jemena	
	CitiPower/Powercor	MIC
	United	
NSW	Ausgrid	AIC
	Endeavour	
	Essential Energy	
ACT	EvoEnergy	AIC
SA	SA Power Networks	AIC
TAS	TasNetworks	AIC
QLD	Energex	LRIC
	Ergon	
NT	Power and Water (2019)	AIC

Source: Energeia Modelling, DNSP Tariff Structure Statements

Energeia also carried out a comprehensive review of LRMC methodologies, inputs and outcomes contained in DNSP TSSs. This was completed to ensure that the LRMC calculation methodology and inputs applied for this project considered best practice and previous regulator feedback. The summary of this further research can be found in Appendix A – Industry Practice Benchmarking.

Finally, Energeia benchmarked LRMC values from the most recent regulatory periods by DNSP. Figure 2 the most recent AER approved values. From a comparison of these values, it is noted that PWC has relatively high LRMC costs, which is most closely aligned to Ergon Energy, another predominantly regional DNSP.

Figure 2 – Comparison of DNSP LRMCs by Customer Type and Voltage Level



Source: Energeia, DNSP Tariff Structure Statements

2. Scope and Approach

PWC engaged Energeia to develop LRMC estimates by voltage level that would be fit-for-purpose and accepted by the AER, to be factored into the tariffs contained in its Tariff Structure Statement (TSS).

Energeia worked closely with PWC to develop and deliver the following scope and approach for this project:

1. **Document Requirements** – Energeia reviewed the regulatory framework, recent determinations and engaged with subject matter experts (SMEs) and stakeholders from PWC to define the key requirements.
2. **Identify Current Industry Practices** – Energeia benchmarked peer Distribution Network Service Provider (DNSP) forecasting methodologies and AER feedback from recent regulatory cycles to identify industry standard practices.
3. **Develop Methodology** – Based on the outcomes from step 1 and 2, Energeia developed a best practice, fit-for-purpose and NT NER compliant procedure for producing LRMC estimates.
4. **Data Gathering and Processing** – Energeia gathered and processed the most recent inputs from PWC for use in the forecasting methodology.
5. **Develop LRMC** – Energeia implemented the methodology determined above to develop LRMC estimates for PWC's 2024-29 regulatory period.
6. **Consultation and Validation –** Energeia worked closely with PWC stakeholders and SMEs to validate the methodology, inputs, and outputs of the LRMC calculation process.
7. **Documentation** – Energeia documented the process, methodology and key inputs used to produce the LRMC estimates in this report.

The following sections detail our LRMC calculation methodology, including the key inputs and assumptions used, followed by the results and their validation.

3. Methodology

This section describes the methodology used to calculate PWC's LRMCs by voltage, which consisted of the following key steps:

1. **Develop Long-Run Marginal Cost Procedure –** Energeia first developed a fit-for-purpose LRMC calculation procedure that satisfied PWC's key requirements and reflected industry best practice.
2. **Data Gathering and Processing –** This step included gathering the key inputs for the calculation, including capital expenditure (capex), comprised of replacement expenditure (repex) and augmentation expenditure (augex), operational expenditure (opex), demand, and allocations by voltage level[27]. Other key inputs included Weighted Average Cost of Capital (WACC), power factors, Distribution Loss Factor (DLFs), calculation time horizon, and extending costs and demand beyond the 2024-29 regulatory control period.
3. **Average Incremental Cost Calculation –** In this step, Energeia calculated incremental demand and costs, to feed into the AIC calculation for the final LRMC calculation by voltage level.
4. **Validate Optimised Results –** Energeia compared the calculated LRMC value with PWC's previous LRMC, and also compared them to other DNSPs' LRMCs. Additionally, Energeia consulted with PWC stakeholders prior to finalisation.

Each stage of the methodology is detailed below.

3.1. Develop Long-Run Marginal Cost Procedure

PWC selected the AIC methodology for calculating its LRMCs by voltage due to its lower net[28] cost, complexity and input requirements, which is consistent with the majority of its peers as demonstrated in Section 1.5. As outlined in Section 1.4 of this report, there are a number of key inputs required for the AIC method by voltage level:

- Expenditure forecasts
    - Repex
    - Augex
    - Connex (not included)
    - Opex
    - Non-system (not included)
    - Overheads (not included)
- Demand forecast
- Distribution loss factors
- Weighted annual cost of capital (WACC)
- Power factor

The AIC LRMC calculation methodology is shown in Figure 3.

[27] Voltage levels included Sub-transmission (ST), High Voltage (HV) and Low Voltage (LV)

[28] The NT Pricing Order means that half of PWC's load would not see any benefit until the Pricing Order was lifted for low voltage customers consuming <750MWh p.a.

Figure 3 – Long-Run Marginal Cost Calculation Methodology Overview

Source: Energeia

This procedure, and in particular the key methods, are further explained below.

3.2. Data Gathering and Processing

This step included gathering and processing the key inputs and assumptions shown in Table 2. Based on a review of best practices and the NT NER, Energeia agreed a number of key assumptions with PWC including the level of repex included, the time horizon (LRMC period), and how costs and demand were extended for years beyond PWC's estimates prepared for the IRP.

Table 2 details the key data sources used in the implemented LRMC methodology.

Table 2 – Data Sources

Data Type	Data Description	Start/End Date	Source
Augex	Real Augex Forecast by Asset Type and Project	2023 – 2029	PWC 2024-29 Reset RIN
Repex	Real Repex Forecast by Asset Type	2023 – 2031	PWC 2024-29 Reset RIN
Maximum Demand	P10 Maximum System Demand Forecast	2022 – 2032	Energeia System Demand Forecasting Model
Demand by Voltage Level	Historical Peak Demand Split by Voltage Level	2021	PWC 2021-22 SCS Pricing Model
WACC	Real Vanilla WACC (Flat) Forecast	2024 – 2029	PWC 2024-29 Post-Tax Revenue Model
Power Factor	Power Factor (Flat) Forecast by Line Voltage	2018 – 2024	PWC 2019-24 Determination Workbook
Distribution Loss Factor	Ergon Average Distribution Loss Factors by Voltage Level	2021	AEMO Distribution Loss Factors for the 2020/21 Financial Year

Source: Energeia, PWC

The following sections detail each of the key inputs and assumptions Energeia used to calculate PWC's LRMC by voltage level.

3.2.1. Capex

Energeia used PWC's forecast of annual repex and augex sourced from the PWC 2024-29 Reset RIN.

Repex

Energeia took PWC's forecast of annual real repex by asset class and category (e.g. Poles <= 1 kV; Concrete)[29] and allocated them by voltage level[30]. Anything without a clear voltage was assigned 'Other' and the total of these costs were pro-rata allocated to a voltage, based on each voltage level's repex. This generated a forecast of annual repex by voltage level[31].

Augex

Energeia took PWC's forecast of annual real augex by asset type (e.g., HV Feeders)[32] and for specific upcoming augex projects (e.g., Darwin - Hudson Creek Spare 132kV Transformer).[33] As with repex, augex was allocated by voltage level[30] to produce the forecast of annual augex by voltage level.

3.2.2. Opex

Energeia assumed opex to be 2.3% of capex per year based on previous analysis of PWC's cost structure, which generate a forecast of annual opex by voltage level.

3.2.3. Demand

Energeia sourced maximum demand forecasts from our report produced for PWC, [34] which include P10[35] maximum demand forecasts by PWC region (Darwin-Katherine, Alice Springs, Tennant Creek). The forecasts were summed and allocated by voltage to produce a system forecast by voltage level.[36]

3.2.4. Weighted Average Cost of Capital

WACC was assumed to be 2.98%, taken from the flat forecast in the PWC 2024-29 Post-Tax Revenue Model.[37]

3.2.5. Power Factor

The power factors by voltage level, for conversion from kW to kVA, were taken from values reported in the PWC 2019-24 Determination Workbook.[38] Table 3 displays the power factors used in the conversion.

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[29] PWC, 2024-29 Reset RIN

[30] See Section 3.4 for detail on allocation assumptions

[31] Energeia set the percentage used in the model to 35% to manage the impact on customers.

[32] Ibid.

[33] Ibid.

[34] Energeia, PWC System Minimum and Maximum Forecast Report, 2022

[35] P10 maximum demand is defined as the expected maximum demand for the 10th percentile of hottest days.

[36] See Section 3.4 for detail on allocation assumptions

[37] PWC, Power and Water 2024-29 Post-Tax Revenue Model, 2022, WACC Tab

[38] PWC, 11.11CP - Regulatory Determination Workbooks – Consolidated, 2018, Table 3.4.3.5

Table 3 – Power Factor by Voltage Level

Voltage Level	Proportion of Peak Demand
ST	0.94
HV	0.98
LV	1.00

Source: Energeia, PWC

3.2.6. Distribution Loss Factor

The distribution loss factors by voltage level, to be accounted for in the incremental demand calculation, were taken from Ergon Energy's 2021 values (as they are not reported for PWC, Ergon is taken as a comparable network) in the Distribution Loss Factors for the 2020/21 Financial Year Report.[39]

Table 4 displays the distribution loss factors used.

Table 4 – Distribution Loss Factor by Voltage Level

Voltage Level	DLF
ST	1.833%
HV	4.867%
LV	12.067%

Source: Energeia, PWC

3.3. Key Assumptions

Key assumptions used in the AIC calculation methodology include asset lifetime, calculation interval, and the extension of the capex and opex costs estimated by PWC for the IRP.

Asset Lifetime

Asset lifetime was assumed to be 40 years, which reflects the 40-50 year typical lifetimes of power transformers and zone substations.

Calculation Interval

The calculation interval, or time horizon, used in the LRMC calculation was set to 20 years. While this is less than the period over which all factors of production become variable, it is consistent with AER approved industry practice, which suggests the AER's view is that the higher costs associated with a 40-50 interval are unjustified.

Extension of Capex and Demand Beyond Forecast Years

As capex (and subsequently opex which was defined as a % of capex) were only forecast to 2028-29 at the latest and peak demand was forecast to 2031-32, both forecasts needed to be extended to account for the assumed 20-year time horizon for the LRMC calculation.

For peak demand, this was done by trending the last 5 years of forecast. Capex was extended by extending its augex and repex components. Repex and augex were in turn extended based on their relationship to incremental demand over the PWC estimated period (shown in Table 5), multiplied by incremental demand.

[39] AEMO, Distribution Loss Factors for the 2020/21 Financial Year, 2020

Table 5 – Calculated Repex and Augex Forecast Extension Factors

Voltage Level	Sum of Incremental Demand (MW)	Sum Of Repex ($M Real)	Sum of Augex ($M Real)	Repex Factor ($M Real / MW)	Augex Factor ($M Real / MW)
ST	84.3	90.56	18.37	1.07	0.22
HV	84.3	124.00	36.79	1.47	0.44
LV	58.3	123.28	13.05	2.11	0.22

Source: Energeia

Energeia recognises the limitations of the above approach, which in effect projects the current stage of the capital cycle for the next 15 years. However, we believe it is a reasonable approach in the circumstances, and consistent with AER approved industry practice.

3.4. Allocation of Expenditure and Demand by Voltage

The allocation of expenditure by voltage level was primarily based on the following assumptions:

- **LV** – Assets <= 11kV or labelled as LV.
- **HV** – Assets > 11kV and <= 22kV or labelled as HV.
- **ST** – Assets > 22kV or labelled as ST.

There were exceptions to these in some instances, such as:

- Zone substation project augex was considered HV (e.g., a 66/11kV substation), except in cases where augex was for exclusively 132kV works.
- In cases where there was an overlap based on the assumptions, e.g., an asset labelled as >=22kV and <=66kV could be considered either HV or ST, a judgment was made from what seemed most appropriate, which was ST in this example.

For allocation of demand by voltage level, historical allocation was taken forward from PWC's public 2021-22 SCS Pricing Model by calculating the proportion of peak demand attributed to each voltage level from 2021.[40] Table 6 shows the resulting demand allocations taken forward for the LRMC calculation.

Table 6 – Peak Demand Allocation by Voltage Level

Voltage Level	Proportion of Peak Demand
ST	0%
HV	29%
LV	71%

Source: Energeia, PWC

Energeia notes that there was zero demand on the ST network to date as there are no ST connected customers. An ST LRMC was estimated assuming all lower voltage demand.

3.5. Average Incremental Cost Calculation

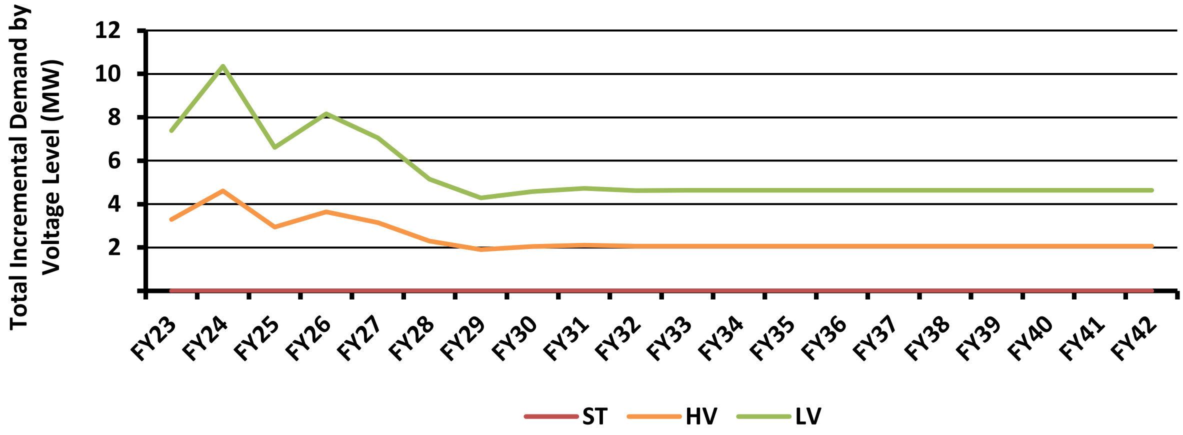
The following sections report on the resulting incremental costs and demand by voltage level used to calculate LRMC by voltage level following the AIC approach.

3.5.1. Incremental Demand by Voltage

Figure 4 displays the 20-year forecast of incremental demand by voltage level used in the AIC formula.

[40] PWC, Appendix 6 - Power and Water Corporation 2021-22 SCS Pricing Model, 2021, Inputs_Volumes Tab

Figure 4 – Total Incremental Demand by Voltage Level



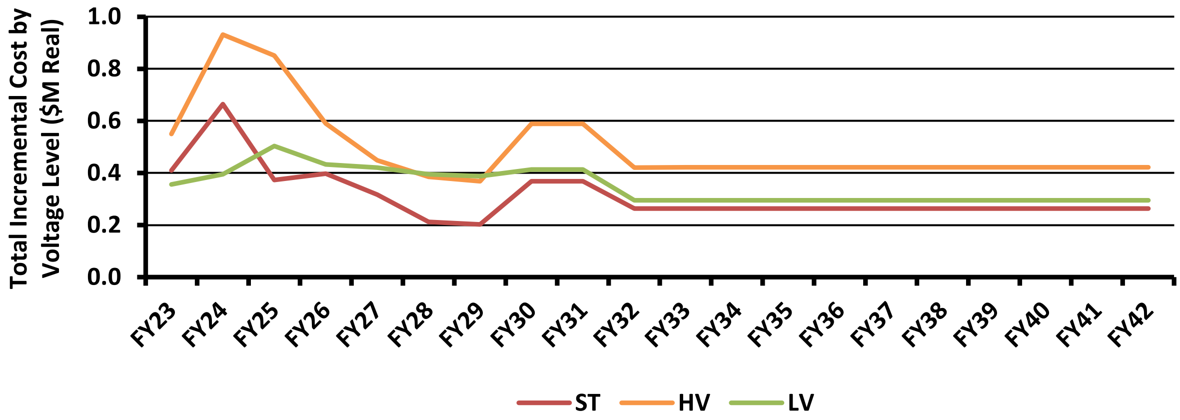
Source: Energeia, PWC

As shown, maximum demand was forecast to be predominantly driven by incremental load at the LV level and no maximum demand was attributed to the ST level.

3.5.2. Incremental Cost by Voltage

Figure 5 displays the 20-year forecast of incremental costs by voltage level used in the AIC formula.

Figure 5 – Forecast Incremental Costs by Voltage Level



Source: Energeia, PWC

Forecast incremental costs are expected to be predominantly at the HV voltage level, with incremental costs at the ST and LV voltage levels about half that of the HV level.

3.5.3. Average Incremental Cost Formula

The AIC formula used is discussed in Section 1.4 and is as follows:

$$LRMC = \frac{PV(new\ network\ marginal\ capex\ and\ opex)}{PV(\ additional\ demand\ served)}$$

Energeia calculated the present value of the incremental costs and demand by voltage level, with the assumed 2.98% WACC and 40-year asset lifetime, to prepare to apply the formula as follows:

$$LRMC = \frac{PV(incremental\ costs\ (20\ year\ horizon))}{PV(\ incremental\ demand\ (20\ year\ horizon))}$$

Once LRMC estimates were developed by voltage level it was grossed up to kVA using assumed power factors to finalise the LRMC calculation in units of $/kVA/year.

3.6. Consultation and Validation

Energeia engaged PWC stakeholders throughout the forecasting process to provide an opportunity for feedback on the validity of the calculated LRMC. Additionally, the result was compared to the LRMCs of other DNSPs for validation. This comparison is shown in Section 4.2.

4. Forecasting Results

This section reports the results of Energeia's LRMC calculation for incremental load or exports during the period of greatest utilisation using the AIC method.

4.1. Calculated Long-Run Marginal Cost

The final calculated LRMC by voltage level, including the contribution of expenditure sub-components, is presented in Table 7.

Table 7 – Calculated LRMC by Voltage Level

Voltage Level	$/kVA/year
ST (Total)	**41.76**
Augex	8.23
Opex	14.52
Repex	19.01
HV (Total)	**103.95**
Augex	31.21
Opex	36.14
Repex	36.59
LV (Total)	**164.90**
Augex	24.91
Opex	57.34
Repex	82.65

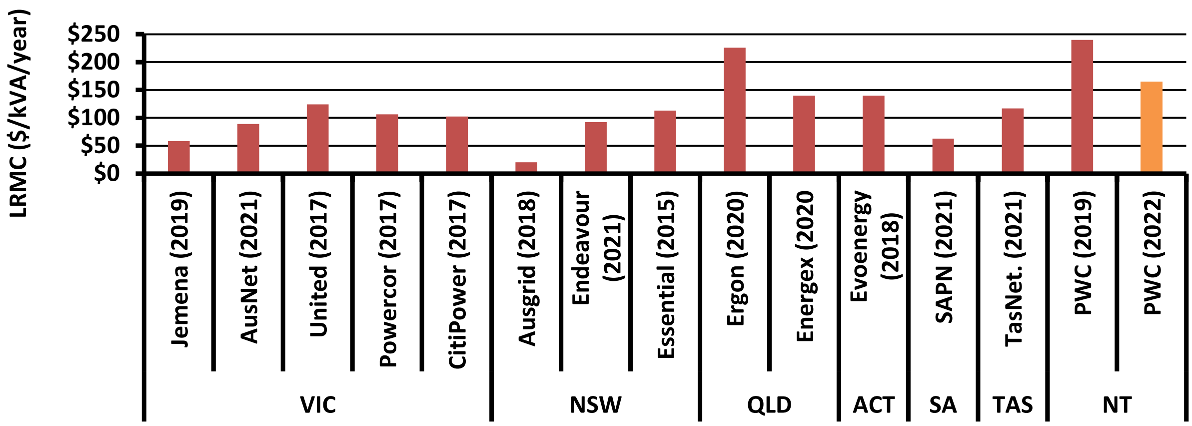
Source: Energeia

LRMC was estimated to be highest at the LV level, followed by the HV level, which is consistent to historical PWC estimates (see Section 1.1). Estimated LRMC for the ST level is significantly lower, and as previously discussed, PWC has no historical estimate at the ST level to compare against.

4.2. Comparison to Other Distributed Network Service Providers

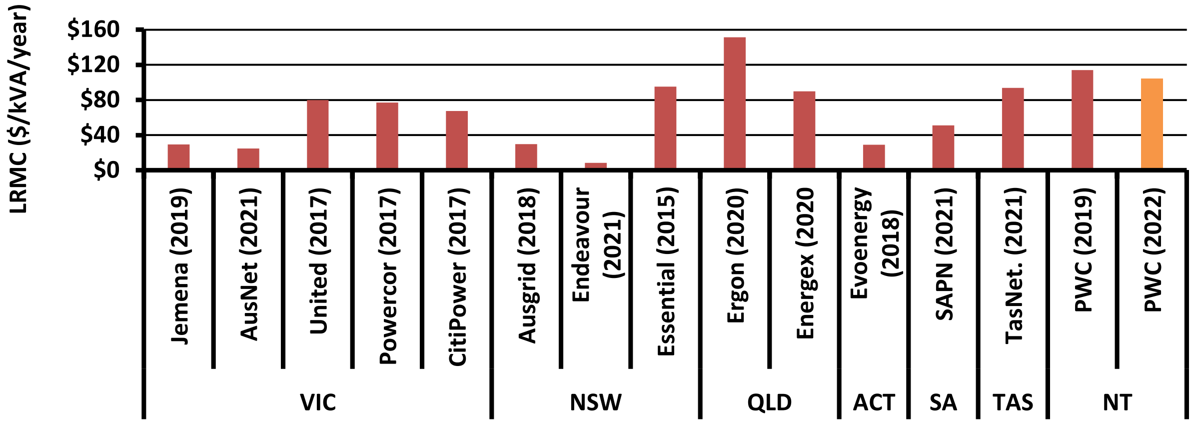
Energeia validated the estimate of PWC's LRMC by voltage level against those historically reported by other DNSPs for their own networks. This comparison is displayed in Figure 6, Figure 7, and Figure 8 for the LV, HV, and ST voltage levels, respectively.

Figure 6 – LV LRMC Benchmarking



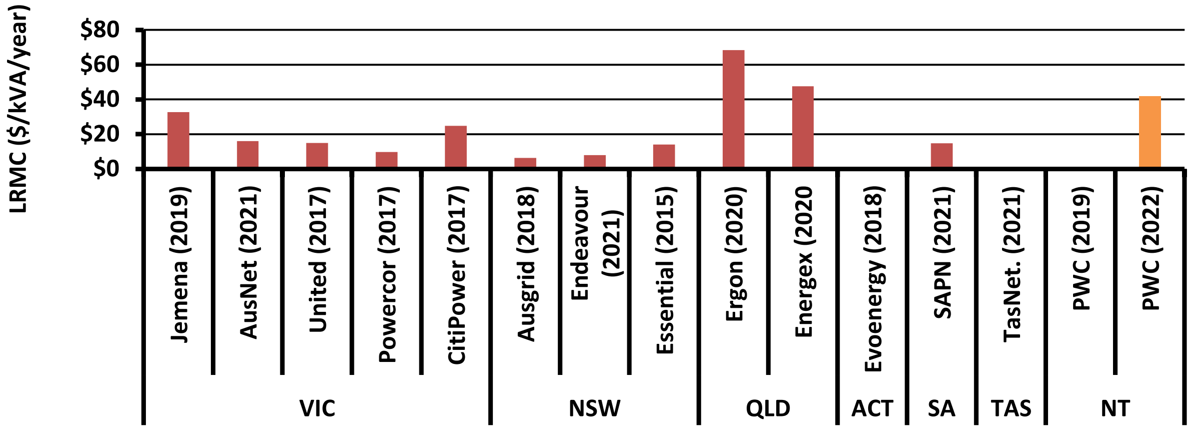
Source: Energeia, DNSP Tariff Structure Statements

Figure 7 – HV LRMC Benchmarking



Source: Energeia, DNSP TSS and Related Documents

Figure 8 – ST LRMC Benchmarking



Source: Energeia, DNSP TSS and Related Documents

Energeia's estimates for PWC's LRMC is consistent with comparable DNSPs (i.e. Ergon Energy) across each voltage level. Furthermore, the LV and HV LRMC estimates are of similar magnitude to PWC's historical estimates at these voltage levels.

Appendix A – Industry Practice Benchmarking

Table A1 – LRMC Inputs and Outcomes

		VIC				NSW			QLD		ACT	SA	TAS	NT
		AusNet	Jemena	CitiPower / Powercor	United	Ausgrid	Endeavour	Essential	Energex	Ergon	Evoenergy	SA Power	Tas Networks	Power and Water
Demand incl. in LRMC	P10/P50/ Raw	P50	Raw	Raw	-	P50	P50	Raw	Raw	Raw	Raw	P10	-	
	NCMD/ CMD	NCMD	CMD	NCMD	-	-	NCMD	CMD	NCMD	CMD	CMD	CMD	-	CMD
	NCMD Basis	ZS	-	ZS	-	-	ZS	-	-	-	-	-	-	
% Expenditure incl. vs. AER FD	Repex	10%	0%	0%	-	1%	142%	10%	-	-	0%	9%	-	5%
	Augex	0%	6%	174%	-	40%	27%	18%	-	-	89%	69%	-	97%
	Connex	0%	21%	0%	-		43%		-	-	109%	0%	-	0%
	Opex %	1.0%	4.3%	0.5%	-	2.0%	2.0%	-	1.5%-2.5%[1]	1.5%-2.5%[1]	2.0%	1.5%-2%	4.5%	2.3%
Time	LRMC Start Year	FY20	FY19	CY16	CY11	FY19	FY19	FY18	FY19	FY19	CY18	FY16	FY20	FY20
	Actual Years in LRMC	FY20	CY19-20	CY16-20	CY11-20	FY19-20	FY19	FY17-19	FY19	FY19	CY18	FY16-20	FY17-19	-
	Forecast Years in LRMC	FY21-30	FY22-29	CY21-25	-	FY21-38	FY20-28	FY20-32	-	-	CY19-27	FY21-38	FY20-29	FY20-FY37
	Total Years in LRMC	11	11	10	10	20	10	15	-	-	10	23	10	18

Source: Energeia Research, DNSP Tariff Structure Statement
CMD: Coincident Maximum Demand
NCMD: Non-Coincident Maximum Demand

Appendix B – Avoidable Cost

This section details the regulatory requirements, methodology, inputs and results of Energeia's calculation of Avoidable Cost for PWC's 2024-29 Tariff Structure Statement (TSS).

Regulatory Requirements

The Northern Territory National Energy Rules (NT NER) specified economically efficient bounds to be maintained when developing network tariffs.

Regarding the Avoidable Cost the NT NER states in Section 6.18.5[41] that:

> *(e) For each tariff class, the revenue expected to be recovered must lie on or between:*
>
> 3. *an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and*
> 4. *a lower bound representing the* ***avoidable cost*** *of not serving those retail customers.*

Energeia calculates the Avoidable Cost for a given customer class by determining:

- the long run marginal cost of the network: and
- the contribution of the customer class to the period of maximum utilisation (i.e. peak demand)

PWC's network tariffs must recover at least this much revenue from a given customer class over the regulatory period to satisfy the NT NER and good economic practice.

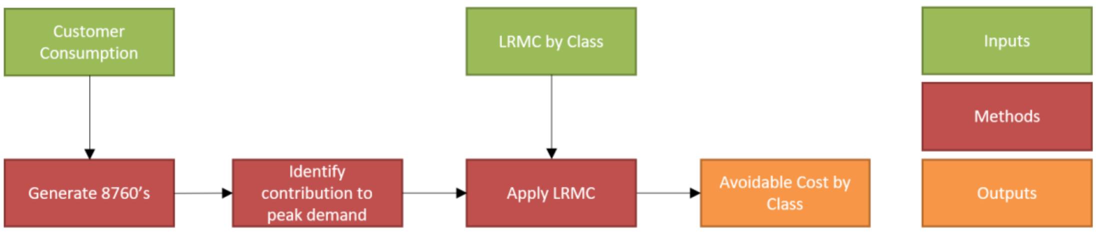
Methodology

Energeia's methodology for calculating Avoidable Cost follows the steps below:

1. **Estimate Peak Day Load Profiles** – Energeia developed forecast peak day load profiles at a tariff class level based on a statistically robust sample of PWC customer smart meter load profiles.
2. **Estimate contribution to Coincident Maximum Demand (CMD)** – Energeia calculated the contribution of each customer segment to network CMD.
3. **Apply LRMC** – Energeia multiplied the appropriate long-run marginal cost (LRMC) to the customer classes' demand during CMD.
4. **Validate** – These results were validated through meeting with and presenting key results to PWC stakeholders.

This process is outlined in the diagram below.

Figure B1 – Avoidable Cost Modelling Methodology



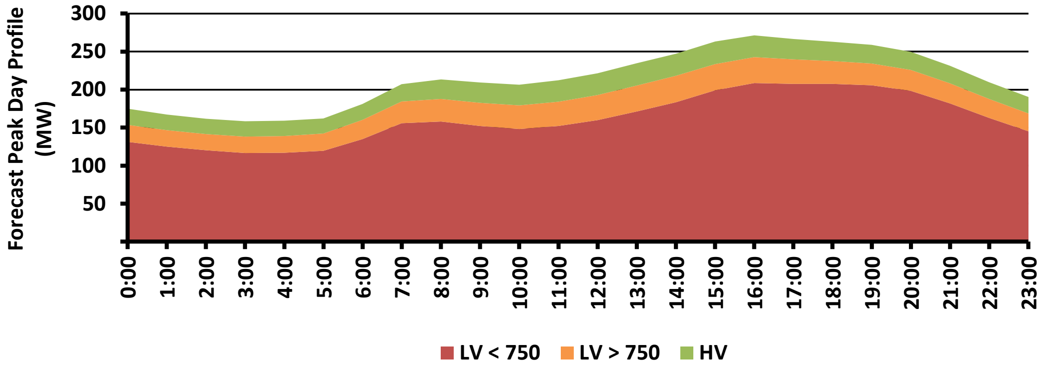
Source: Energeia

[41] National Electricity Rules as In Force in the Northern Territory Version 96 Section 6.18.5e (1,2)

Estimate Peak Day Load Profiles

Energeia first estimated the CMD day load profile by customer class using a statistically robust sample of customers. The resulting CMD day load profile is reported in the figure below.

Figure B2 – Forecasted System Peak Day Profile



Source: Energeia Modelling, PWC

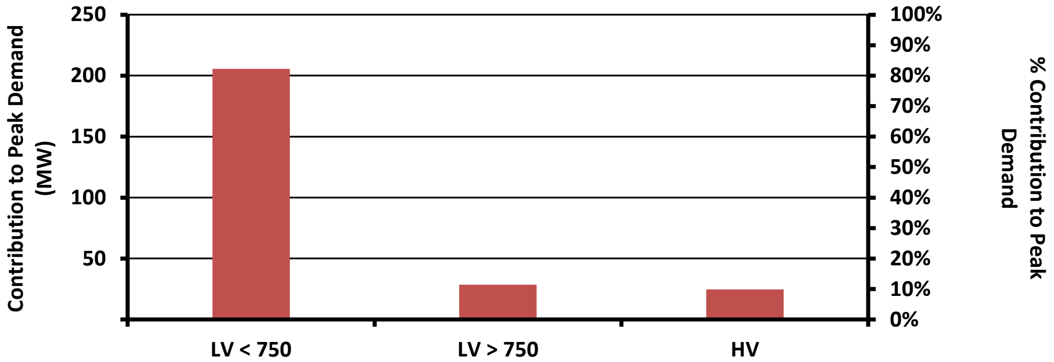
The analysis shows the LV < 750 MW customer class as using most of the network capacity during the period of greatest utilisation.

Energeia's utilised the methodology outlined in PWC's demand forecasting additionally undertaken by Energeia for PWC's regulatory proposal to determine the likely timing of peak demand in a given year. Energeia used these profiles to estimate the contribution of each class to peak demand on the network in a given year, outlined in the following section.

Estimate Contribution to CMD

Energeia then calculated the contribution of the of each class to the CMD day peak load, the results of which are reported in the figure below.

Figure B3 – Contribution to Peak Demand – FY27



Source: Energeia Modelling, PWC

Apply LRMC

LRMC unit rates reported in the main body of this report were then applied to the estimated peak demand to generate annual Avoidable Costs by class. The resulting Avoidable Costs for FY27 are reported in the table below.

Table B1 – Avoidable Cost by Class

Voltage Level	$/year
< 750 LV	$64,532,622
> 750 LV	$8,842,891
HV	$7,621,604

Source: Energeia Modelling

Appendix C – Standalone Cost

This section details the regulatory requirements, methodology, inputs and results of Energeia's calculation of Standalone Cost for PWC's 2024-29 Tariff Structure Statement (TSS).

Regulatory Requirements

Standalone Cost falls under the same section of the Northern Territory National Energy Rules (NT NER) as avoidable cost which specifies[42]:

> *…*
>
> *(e) For each tariff class, the revenue expected to be recovered must lie on or between:*
>
> 1. *an upper bound representing the* ***stand alone*** *cost of serving the retail customers who belong to that class; and*
> 2. *a lower bound representing the avoidable cost of not serving those retail customers.*

Energeia calculates the Standalone Cost for a given customer class by determining:

- Representative customer profile for the given class; and
- Costs incurred for a stand-alone power system (SAPS) providing comparable level of service

PWC's network tariffs must recover no more than this much revenue from a given customer class over the regulatory period to satisfy the NT NER and good economic practice.

Methodology

Energeia's methodology for calculating Standalone Cost follows the steps below:

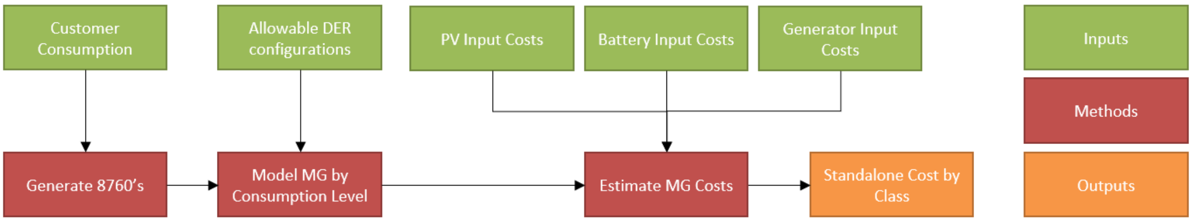
1. **Estimate Annual Load Profiles** – Energeia determined the 8,760 demand profile[43] for a representative customer by class.
2. **Develop SAPS Inputs and Assumptions** – Energeia estimated SAPS input costs and assumptions, including:
   a. Solar PV (photovoltaic) system.
   b. Battery system.
   c. Internal Combustion Engine (ICE) generator.
3. **Estimate SAPS Costs** – Energeia modelled the cost to the class to disconnect from the network based on the representative customer load profile and stand-alone power system (SAPS) annualised cost of service.
4. **Validate –** These results are validated through meeting with and presenting key results to PWC stakeholders.

[42] National Electricity Rules as In Force in the Northern Territory Version 96 Section 6.18.5e(1,2)

[43] Hourly demand profiles for the 8,760 hours in a year

Energeia's Standalone Cost calculation methodology is diagrammed in the figure below.

Figure C1 – Stand Alone Cost Modelling Methodology

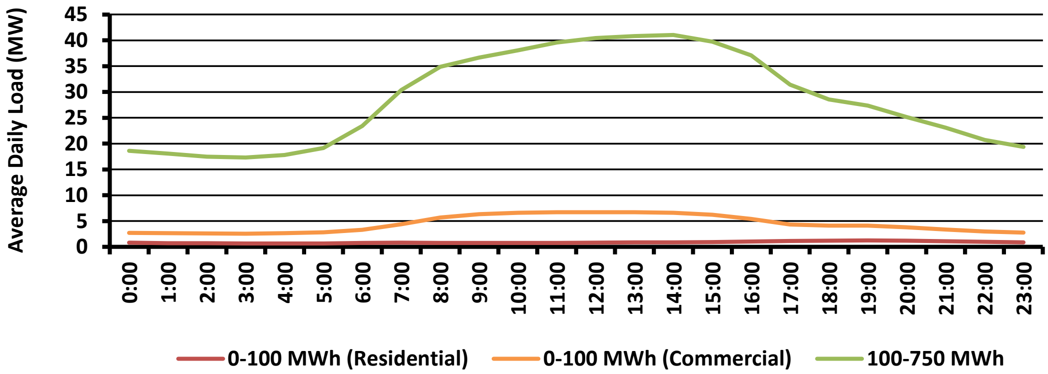


Source: Energeia

Estimate Annual Load Profiles

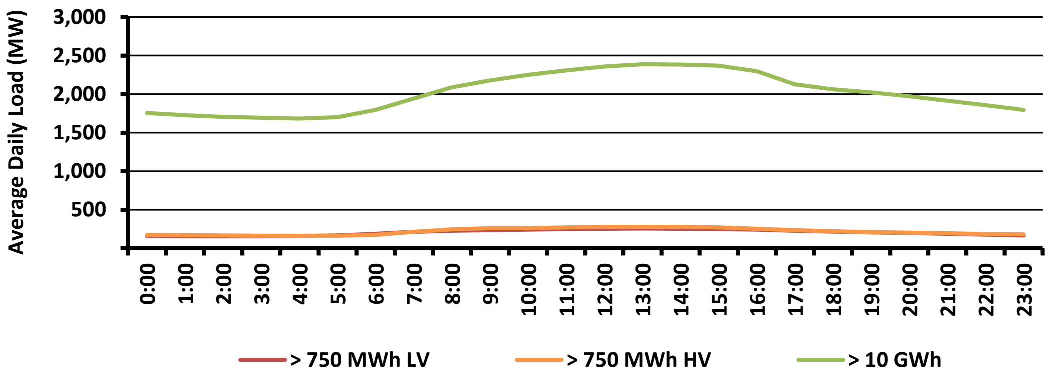
The representative load profiles used for the <750 MWh class is shown in Figure C2, and the >750 MWh class in Figure C3. They were sourced from a representative sample of smart meter customers will a full year of load profile data on PWC's network. The customer with annual consumption closest to the median of that sample was selected as the most representative for a given tariff class.

Figure C2 – Average Day Customer Load Profiles < 750 MWh



Source: PWC, Energeia Modelling

Figure C3 – Average Day Customer Load Profiles > 750 MWh



Source: PWC, Energeia Modelling

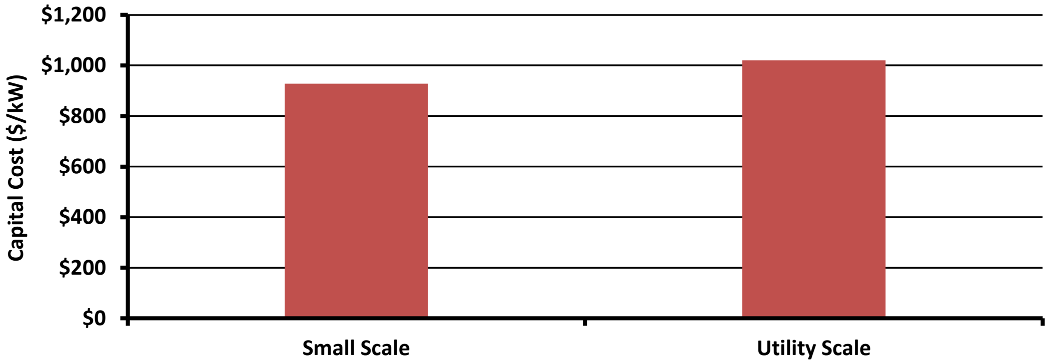
The above load profiles are used to size and configure a SAPS capable of meeting the entire energy needs of the customer without connection to PWC's existing network, using a combination of solar PV, battery storage and ICE generator.

Develop Key Inputs and Assumptions

Solar PV

The figure below shows Energeia's assumptions for solar PV capital expenditure, which varied by size. The step was set at 100 MW, with below eligible for small scale and above allocated utility scale systems.

Figure C4 – PV Capital Cost

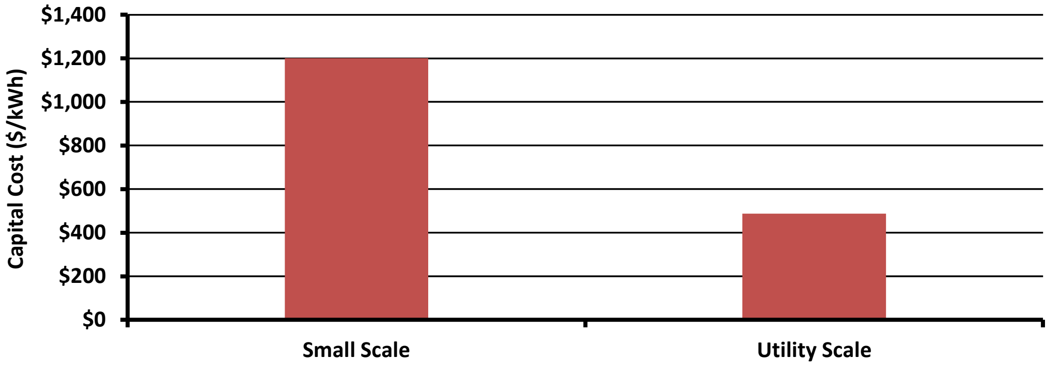


Source: CSIRO GenCost (2022)

Storage

Cost assumptions for battery storage are detailed in the figure below. The allocation of battery systems by small and utility scale aligns to the PV systems in the section above.

Figure C5 – Battery Capital Cost



Source: CSIRO GenCost (2022)

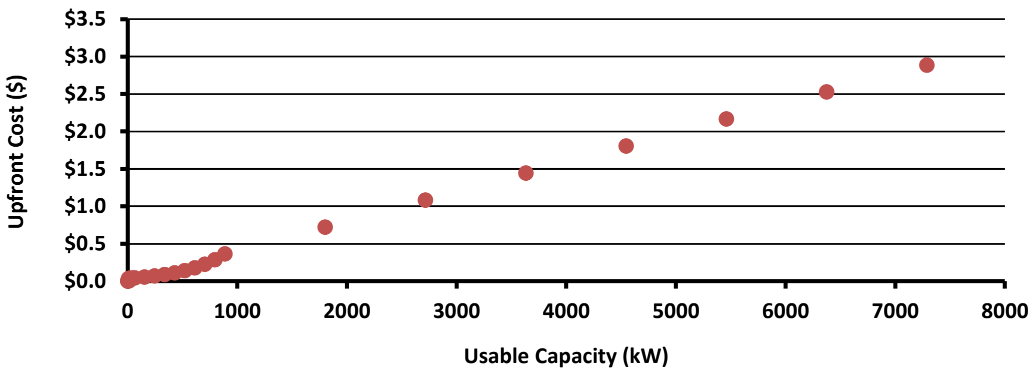
ICE Generator

The following table outlines the key input assumptions for onsite generators. Both petrol and diesel generators were available as inputs for microgrids, with fuel type optimised by generator size.

Table C1 – Eligible Generator Size by Capacity

Generator Size (kW)	Fuel Type	Efficiency (kWh/L)
0-8 kW	Petrol	1.57
> 8 kW	Diesel	4.06

Figure C6 – Generator Capital Cost by Installed Size

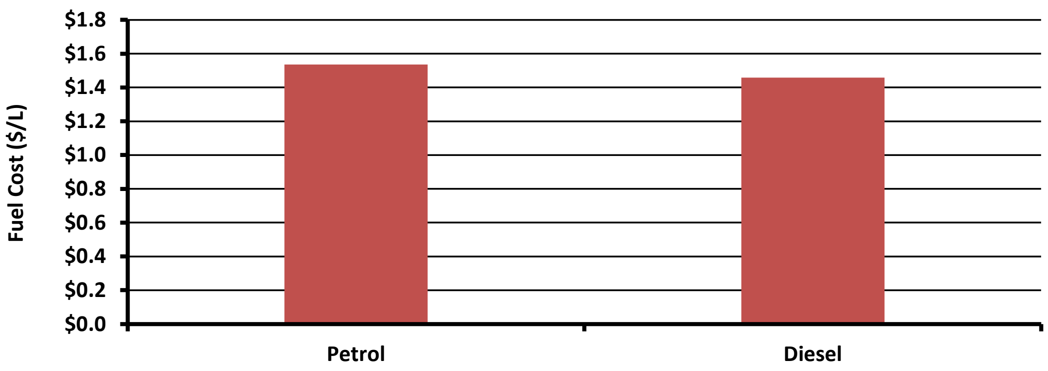


Source: Energeia Research

ICE Fuel Costs

The following fuel costs assumptions were used for the modelling, shown in the figure below.

Figure C7 – Generator Fuel Costs ($/L)



Source: Energeia Modelling

Estimate SAPS Cost

Energeia modelled Standalone Costs using the key inputs and assumptions above.

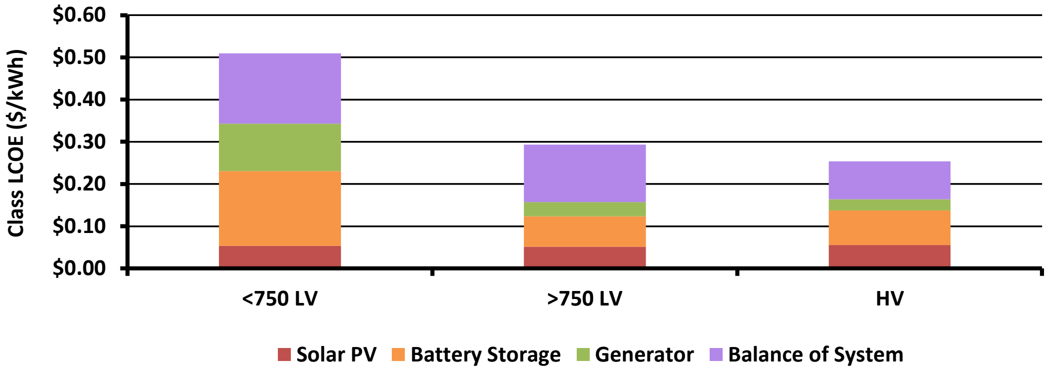
The following steps were used to develop an optimised SAPS by customer size:

1. **Size PV and Battery Sizing**– The solar PV and battery components were sized to minimise cost of service using a linear solver.
2. **Size ICE Generator** – The ICE generator was sized to meet the largest half-hourly demand net of solar PV and storage, or the maximum[44] gross load, whichever was highest.

This modelling generated a levelized cost of energy (LCOE) for a SAPS customer based on annualised fixed and variable costs and annual consumption, as well as the cost of balancing the system, which was assumed to be equal to network LRMC. The results are shown in the figure below by different customer groups and was used to determine the Standalone Costs of PWC's customers by class.

[44] This provides a near n level of system reliability, similar to rural areas of the grid with radial feeder networks.

Figure C8 – LCOE by Customer Type



Source: Energeia Modelling

The LCOE was applied to the total forecast annual consumption of all customers by class to get annual Standalone Costs. The final calculated Standalone Cost by class level is presented in the table below for FY27.

Table C1 – Standalone Cost by Class

Voltage Level	$/year
< 750 LV	$525,175,824
> 750 LV	$76,882,098
HV	$135,406,662

Source: Energeia Modelling