Demand Side Engagement Framework

CitiPower Pty Ltd, Powercor Australia Ltd
CPPAL-FW-0001

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1. Introduction

CitiPower and Powercor (CPPAL) have provided this Demand Side Engagement Framework as our 'Industry Engagement Document' to assist non-network providers in understanding our processes for consultation on and assessment of demand side options.

As the energy transition is generally seeing consumers depend more on electricity to meet their changing needs, non-network options have an increasingly important role to play as an alternative to network development. Where they are both technically feasible and economic, non-network options can help to address localised constraints in the network to either defer or remove the need upgrade / develop the network.

This engagement document provides information on how CitiPower and Powercor engage with non-network providers and how we will consider non-network options. It is aligned with the requirements of clauses 5.13.1 (e) to (j) of the National Electricity Rules (NER) and contains the detailed information set out in Schedule 5.9 of the NER.

CitiPower and Powercor aim to review this engagement document at least once every three years or as required by any changes in the NER.

2. Network Opportunities

2.1 Overview

Historically, CitiPower and Powercor have built new electricity infrastructure to meet increasing demand for electricity from our customers. This has involved augmentation of the network by, for example, installing a new transformer at a zone substation and building new powerlines to areas of demand growth. Additionally, when network assets are reaching the end of their operating lifetime, we may also seek to replace them with more modern assets and systems. These interventions are generally referred to as 'network solutions' as they involve development of the traditional electricity network. In addition to capacity constraints on networks, more recently constraints due to voltage variations have also required network investment to meet our obligations under the Electricity Distribution Code of Practice (EDCoP) and ensure customers receive electricity supply at the required quality.

The development and ongoing maintenance of these conventional network solutions may be expensive and, as technology changes, more economical 'non-network solutions' may become available. Such non-network solutions may be temporary, simply deferring the need to upgrade the network by a number of years creating both optionality and reducing costs in the short term. They may also provide a more permanent solution, especially in areas at the edge of the network where they could replace the need to build network entirely.

Electricity distribution networks are built to deliver electricity under a range of credible conditions. CitiPower and Powercor plan our networks to cater for the expected level of customer demand on an economic basis, using metrics defined by the Australian Energy Regulator (AER) such as the Value of Customer Reliability (VCR) to quantify the value that different customer segments place on reliable electricity supply under varying conditions and across different locations. VCR plays an important role in ensuring customers pay no more than necessary for reliable supply, helping electricity networks identify both the right interventions and the timing for those investments.

Our forecasting and planning processes use AER metrics alongside a number of factors including statistical temperature forecasts, new connections uptakes and changes in customer energy usage patterns to develop our forward plans. In the majority of cases excluding safety and compliance, the trigger for investment comes when the benefits to our customers outweighs the costs.

This chapter sets out the general factors that drive network investment and how non-network solutions may assist in either deferring or replacing the need for investment.

2.2 Peak Demand

The highest 'peak demand' from customers typically occurs over only very short periods of the year and for very short durations. The graph in Figure 1 shows the peak demand for the Powercor network as a whole, as supplied from the transmission network over the full year of 2023. While the network reached a coincident peak demand of ~2,050 MW in 2023, this lasted for less than 2 hours and the network as a whole was only above ~1,760MW for less than 0.5% of the year.

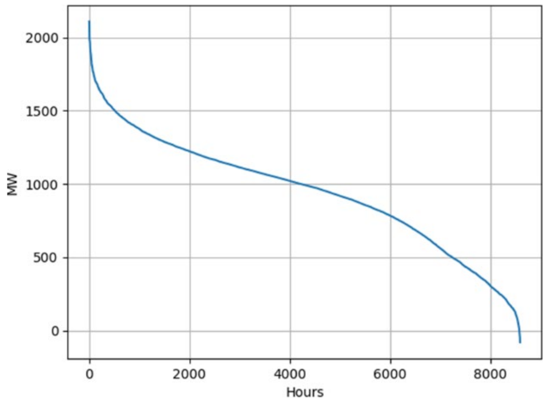

Figure 1: Example Powercor Network Level Load Duration Curve for 2023

Peak demand varies both with seasons and with geography and areas of the network can be either 'summer peaking' or 'winter peaking' and, on occasion, can swap between summer and winter peaking year on year.

Types of non-network solution that may help to support peak demand constraints can include:

- Connection of generation or battery storage to support peak demand locally;
- Demand reduction to lessen the impact on network and reduce a peak demand level;
- Construction of Stand Alone Power Systems (SAPS) to remove a portion of demand from the network.

2.3 Asset Replacement

Our networks contain assets of varying age profiles and, as assets age, it is expected that their condition will deteriorate over their lifetime to the point where replacement is needed. Across our networks we use a whole of life, whole-system cost approach (WLWS) to asset management. Reliability Centred Maintenance (RCM) principles are used to manage the network assets over their life cycle. To make the assessment, Powercor:

- Identifies the key components, and functions of the asset class
- Performs a Failure Mode, Effects and Criticality Analysis (FMECA) to assess component failure, and the effect of the failures on asset function
- Determines cost-effective techniques (where possible) to manage risk resulting from failure modes
- Combines tasks into maintenance packages for implementation
- Reviews and improves asset and maintenance performance as necessary.

While non-network solutions cannot remove the need to replace assets at the end of their lives, they may help to support an asset replacement project and potentially reduce the scope of a replacement. This could be achieved through demand reduction or connection of generation / battery storage to reduce the impact of peak demand and reduce the capacity required from the new assets.

2.4 Network Reliability

CitiPower and Powercor use a risk-based approach to plan and deliver improvements to both reliability and resilience performance. Risks are managed initially by the response to faults and outages, and by close attention to metrics for reliability and incentive or penalties such as Service Target Performance Incentive Scheme (STPIS) and the Guaranteed Service Level (GSL) schemes respectively. Monitoring these metrics confirms whether adequate controls are in place to maintain reliability and identifies whether new controls or interventions are required.

Reliability projects are part of the controls that seek to maintain and improve network performance for customers. Non-network solutions can support reliability outcomes by minimising the number of customers affected by an outage or aiding in supply restoration.

2.5 Voltage Performance

Maintaining control of voltage within set parameters is a legislated requirement under the Electricity Distribution Code of Practice (EDCoP) and the National Electricity Rules. This covers our ability to control voltage at connection points to the transmission network, to large customers on the distribution network and at the individual meters of every customer we supply. Ongoing analysis of the data from customer smart meters enables us to track performance against our compliance obligations and report this compliance to the Victorian Essential Service Commission.

Network investment may be proposed to maintain voltage compliance for a number of reasons and, in these cases, non-Network solutions may be able to defer or avoid this expenditure.

3. Non-Network Engagement

3.1 Overview

CitiPower and Powercor are always seeking to ensure that the planning and developing of our network is efficient within the current regulatory context. In line with the requirements of Chapter 5 of the National Electricity Rules (NER), we regularly publish a range of engagements to publicise our plans for network development and seek interest in provision of non-network solutions and network support services. These publications and engagements include:

- Distribution Annual Planning Reports (DAPR): This report sets out the plan for capacity and compliance development of our distribution networks based on forecasts over the next 5 years. It provides information on any emerging system limitations, planned projects and projects currently in delivery.
- Network Visualisation Portal: This portal provides more geographic context for our networks today and the constraints published in our DAPRs.
- Transmission Connection Planning Reports (TCPR): This report is created in collaboration with all Victorian distribution networks and the transmission network service providers who provide connections for distribution. It sets out the plan for capacity and compliance development of our connection points based on forecasts over the next 10 years.
- Regulatory Investment Tests: As required by the cost of a project, we will issue Regulatory Investment Tests for Distribution (RIT-D) and Regulatory Investment Tests for Transmission (RIT-T) to both publicise the analysis we've undertaken and seek non-network solutions to materially defer the proposed works.
- Annual Non-Network Tenders: We have been proactively advertising for non-network solutions since 2020, beyond the requirements of the Regulatory Investment Test process. In early 2024 we launched our online non-network procurement platform trial in collaboration with Piclo as a way to improve our search for efficient non-network solutions and to better build the non-network solutions market.

The following sections provide some key information on our main methods of engagement seeking non-network solutions.

3.2 Regulatory Investment Test

The process and requirements for Regulatory Investment Test for Distribution (RIT-D) and Regulatory Investment Test for Transmission (RIT-T) are set out in clauses 5.17 and 5.16 respectively and 5.15 generally. With the majority of a distribution networks RIT's being focused on RIT-D's the main areas of interest for non-network service providers relate to the Non-Network Options Report as set out clause 5.17.4(b) to (h) of the NER. The Non-network Options Report is a first step required to engage on these projects and is required to contain:

- a description of the identified need;
- the assumptions used in assess the identified need;
- if available, the relevant annual deferred augmentation charge associated with the identified need;
- the technical characteristics of the identified need that a non-network option or SAPS would be required to deliver such as location, size and operating profile;
- a summary of potential credible options to address the identified need, including both network, non-network solutions and SAPS options.
- for each potential credible option, the RIT-D will provide, to the extent practicable, information on:
    i. a technical definition or characteristics of the option;
    ii. the estimated construction timetable and commissioning date; and
    iii. the total indicative cost (including capital and operating costs);

Anyone registered on the demand-side engagement register will be notified when a new Non-network Options Report Draft Project Assessment Report (DPAR) or Final Project Assessment Report (FPAR) is published as part of a RIT-D process and the report will be published on our website. CitiPower and Powercor will provide stakeholders with at least three months to comment on the Non-network Options Report, six weeks for a DPAR or 30 days for a FPAR.

3.3 Non-network Procurement Platform

In 2024 we launched our new non-network procurement platform trial using the Piclo platform which has been successfully implemented in other jurisdictions globally to build an open market for non-network solutions. The non-network procurement platform provides a clear transparent overview of network constraint information such as time of day, magnitude and seasonality of the constraint. It also enables multiple Flexible Service Providers (FSP's) to bid on constraints, such that a 'least cost' combination of non-network solutions can be defined.

Network constraints are published on the platform annually with high level information to ensure that third parties can only bid when their non-network asset meets the parameters of the constraint. Before FSP's submit either formal bids or expressions of interest for a network constraints they must first register both their company and their assets within the platform.

- Company Qualification: Involves providing information about the company's financial status and ability to fulfil potential contractual obligations.
- Asset Qualification: Involves providing specific details of the assets which will be considered to provide flex services. This includes the status of the asset (in service or proposed), technical specifications and whether they are proven technology which can be integrated into the network.

FSPs that have gained approval both for their company and assets, and that have either existing or proposed assets located within the supply area of a network constraint, can then either:

1. Provide an expression of interest for a future constraint that is not yet completed assessment;
2. Provide a formal bid to a 'Competition' that is seeking firm commitments for a constraint.

While a non-network procurement platform is not intended to replace the need to publish our DAPR or RIT-D documents, it will act as an extra tool to gauge market interest and capability to supply non-network solutions.

CitiPower and Powercor are seeking to continue development of the non-network procurement platform into the future, and will be partnering with a third-party to facilitate this development in coming years.

3.4 Industry Engagement Register

We currently maintain registers for parties to notify us of their interest in being advised of developments relating to the planning and expansion of the networks, this is known as the Industry Engagement Register.

Any notifications will include information about publication of non-network options paper relating to a RIT-D's or our annual flexibility tenders. CitiPower and Powercor will use this register not only to consult with interested parties, but also to determine the level of interest and ability to participate in the development process for non-network options.

To be included on the register, please lodge your details via an Email to:
DMInterestedParties@powercor.com.au and / or DMInterestedParties@powercor.com.au

4. Non-Network Assessment

4.1 Overview

This chapter sets out the process and consultation with non-network providers that CitiPower and Powercor will undertake when addressing a current or future constraint. While there are a range of processes used to engage, assess and select non-network solutions they will generally follow the same process of screening, assessment and selection detailed in the following sections.

4.2 Screening Non-Network Solutions

Once a future network constraint has been identified, a range of possible solutions will be considered to address that constraint in terms of both traditional network solutions and any known non-network solutions. An initial assessment of the appropriateness of each possible option will be conducted. This will take into account the functionality of the network at the point of a constraint and consider whether any possible solution meets national and jurisdictional technical obligations. The technical analysis will also consider any impact of the potential option on other customers and network users.

High level design work will be required for each possible option, which considers the appropriate equipment and standards that would have to be met. It may also consider the relevant safety, regulatory and environmental considerations, and whether consent may be required from third parties.

In some cases, we may discuss a possible non-network option with one or more participants from our industry engagement register (Section 4), with registered flex service providers on our non-network procurement platform (Section 3) or via a specific non-network options report as part of a RIT-D process (Section 3.2).

4.3 Non-Network Proposals

A proposal for a Non-Network solution, either in response to a non-network options report from a RIT-D or from the non-network procurement platform, will require key information in order to be assessed. Any non-network proposal should provide a minimum of the following information:

- Overview of the proposal including the extent to which it addresses the identified need;
- Technical description of the proposal, including but not limited to:
  - Location of assets;
  - Size of the load reduction or additional supply;
  - Network connection requirements, if needed;
  - Contribution to power system security or reliability;
  - Contribution to power system fault levels;
  - Operating profile and reliability of operation;
  - How the proposal meets technical standards and statutory requirements;
- Timing of delivery of the solution and its estimated lifespan, including any additional costs at end of contract term;
- Any potential risks associated with the proposal and any actions that can be taken to mitigate these risks. This should address the risk of not meeting the network support requirement and how any penalties for failure to do so will be addressed.

CitiPower and Powercor will review each non-network option and may seek further information from the non-network provider to better understand the design of the proposed solution and its implications on the network and other network users.

4.4 Assessment of Non-Network Proposals

Assessments will consider the extent to which any non-network solution proposed is a credible option and addresses the identified network constraint while leading to a material deferment of a network solution, that would otherwise be planned to be undertaken to address the network constraint. The option also needs to be both technically and commercially feasible.

Where the option is credible but does not fully meet the needs of a constraint, consideration may be given to a hybrid option which combines one or more non-network solutions or non-network and network solutions.

The criteria that are used to assess each non-network proposal include:

- Type of action or technology proposed to reduce or meet the network need;
- Reliability of the proposed solution compared to the network solution;
- Time required to implement the proposed solution, and any period of notice required before activation;
- Length of time that the network augmentation is deferred;
- Implications of the life-cycle of the asset including the predictability and effectiveness of the possible option;
- Quantification of material market benefits; and
- Quantification of costs to implement, operate and maintain, including cost:
  - to complying with laws, regulations and applicable administrative requirements;
  - that may fall onto CitiPower, Powercor or United Energy should the non-network option fail to be available when called upon (e.g. STPIS penalties).

In addition, we may consider other information that is relevant to assisting in the investigation and evaluation of a non-network proposal. This will include the possible implications of the non-network solution on other network users.

4.5 Ranking & Selection of Solutions

In assessing, ranking and selecting a preferred option to address an identified need, our goal is to define the solution that maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. In this assessment market benefits and costs of each option will be quantified and the credible option with the highest net economic benefit will receive the highest ranking.

Sensitivity analysis may also be undertaken for key input variables to assess whether that is likely to change the ranking of credible options. An example scenario is shown in Table 1 below where there are five credible options to address a network constraint.

Table 1: Credible Options

Credible option	Market Benefits	Costs	Net Economic Benefit	Rank
Network Upgrade Option 1	11.3	11.9	-0.6	5
Network Upgrade Option 2	18.0	17.0	1.0	3
Embedded Generation	13.5	12.4	1.1	2
Demand-Side Engagement	0.9	0.5	0.4	4
Hybrid Demand-Side & Network Upgrade	14.0	12.0	2.0	1

Source: example taken from AER, Application guidelines Regulatory investment test for distribution, August 2022, p. 53.

4.6 Worked Examples

This section provides high level examples of the process that CitiPower and Powercor will follow to assess non-network options to meet network constraints. It is intended to familiarise stakeholders with the process at a high level.

Worked Example 1: Powercor identifies that a particular Zone Substation has a future constraint, with peak demand increasing at an average rate of 1MW per year which is forecast to exceed the zone substations capacity in 2027.

The capital cost to Powercor to address this network constraint with a network solution is estimated at $15 million, above the $7 million RIT-D threshold.

Powercor engineers consider a range of non-network options and is assisted by discussions with some providers on the demand-side engagement register and flex service providers registered on the non-network procurement platform. Powercor determines that non-network options may be able to individually or jointly address the network constraint.

Powercor commences the RIT-D process and prepares a Non-network Options Report and publishes it on its website. At the same time, interested parties on the demand-side engagement register are notified and the constraint is published on the non-network procurement platform.

Stakeholders are given three months to prepare responses to the paper. Responses are received from several providers including ACME Generator Solutions. ACME includes a detailed non-network proposal for a possible solution involving portable gas fired generator sets that can be incrementally added during the contract period.

The ACME proposal is found to satisfy the technical requirements of the solution. The planning engineer holds discussions with ACME to identify reliability, connection augmentations and connection issues. Payments such as Network Use of Service, network support and avoided Transmission Use of System (TUoS) are identified, and ACME agrees to indemnity payments under the Service Target Performance Incentive Scheme.

For each network and non-network option, Powercor estimates the market benefits of the option taking into account different scenarios for growth in peak demand. The construction, operating and maintenance costs of each option are also calculated. Powercor ranks the expected net economic benefit of each credible option. The highest ranked credible option is the ACME non-network solution.

Powercor publishes a Draft Project Assessment Report (DPAR) if the investment option is above $14 million which identifies the preferred option and provides a detailed description of the analysis and methodologies used. Stakeholders are given six weeks to provide comments on the DPAR.

Powercor reviews the submissions to the DPAR, but the non-network solution remains the preferred option. Negotiations with ACME are finalised. Powercor includes the Final Project Assessment Report (FPAR) as part of its Distribution Annual Planning Report (DAPR), and at the same time notifies parties on its demand side engagement register.

Worked example No. 2: An area planning specialist at CitiPower identifies that a 40km long sub transmission line has a future constraint. Peak demand is increasing at an average rate of 0.5MW per year and this is forecast to exceed the capacity of the line in the summer of 2025/26.

The capital cost to CitiPower to upgrade the conductors to address the network constraint is estimated at $8 million which is above the RIT-D threshold.

The planning specialist considers a range of non-network options and is assisted by discussions with some providers listed on the demand-side engagement register and flex service providers registered on the non-network procurement platform. CitiPower determines that some non-network options may be able to individually or jointly address the network constraint, be both technically and commercially feasible and be able to be implemented in sufficient time.

CitiPower commences a RIT-D and prepares a Non-network Options Report and publishes it on the CitiPower website. At the same time, interested parties on the demand-side engagement register are notified and the constraint is published on the non-network procurement market platform.

Stakeholders are given three months to prepare responses to the Non-network Options Report. Some stakeholders provide non-network proposals which discuss how their proposed solution would address the future network constraint, including a technical description and other required information. This includes proposals from:

- a demand management aggregator;
- a diesel generator company; and
- a solar energy provider proposing a solution combining a solar energy with battery storage.

CitiPower estimates the market benefits and costs of each option, taking into account different scenarios for growth in peak demand. The expected net economic benefit of each credible option is calculated, and the highest ranked option is the network solution. CitiPower determines that no non network solution can meet the network need.

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CitiPower includes the Final Project Assessment Report (FPAR) as part of the Distribution Annual Planning Report (DAPR), and at the same time notifies parties on the demand side engagement register.

5. Payment Flows Between Parties

5.1 Overview

Where a non-network solution has been identified as a possible credible option through annual tenders or a RIT-D process then CitiPower or Powercor will need to discuss payments and contractual arrangements with the non-network provider in accordance with internal processes and procedures.

CitiPower or Powercor will apply the following principles when approaching discussions with non-network providers relating to payments:

- negotiation in good faith;
- limiting the exposure of CitiPower or Powercor and its customers to potential costs arising from failure of the non-network solution to deliver the stated solution; and
- appropriate sharing of risks from any failure of the non-network solution.

5.2 Payments made by the Non-network Provider

There are two main categories of payments that flow from the non-network provider to CitiPower or Powercor :

- Network Use of Service payments (NUoS); and
- Indemnity payments for failure to provide a service.

5.2.1 Network Use of Service

NUoS charges are a payment that is passed to any customer to recover the costs of the ongoing operation of the network as required under the national or jurisdictional requirements.

5.2.2 Indemnity for Failure to Provide a Service

The amount of compensation to be provided by the non-network provider to CitiPower or Powercor in the event of a failure to provide network support services will relate to:

- The costs incurred by CitiPower or Powercor;
- The impact on the applicable service adjustment;
- Any immunities to which CitiPower or Powercor may be entitled.
- Any customer compensation payments

This will include any foregone incentives or penalties incurred by CitiPower and Powercor to drive reliability improvements under the Service Target Performance Incentive Scheme (STPIS). STPIS risk will be transferred to the non-network solution provider as part of the contractual arrangement to address degradation of reliability caused by failure to provide the required service.

5.3 Payments made by CitiPower and Powercor

There are two main categories of payments that flow from CitiPower and Powercor to any non-network solution provider:

- Network support payments; and
- Avoided 'Transmission Use of System' (Avoided TUoS) payments

5.3.1 Network support payments

Network support payments are the main payment for provision of a service which defers the need for a traditional network solution. The scale and frequency of this payment will be directly related to the network constraint that is being supported and is usually defined to be lower than the annualised cost of the traditional network solution that is being deferred.

5.3.2 Avoided Transmission Use of System Charges

Transmission Use of System Charges (TUoS) recover the costs for development and ongoing operation of the transmission network from energy all users. Embedded generation within a distribution network avoids a TUoS charge being incurred, while still meeting customers supply needs. When TUoS has been avoided by a network normal billing processes mean that a TUoS payment has still been recovered from end users. As a result, embedded generators within a distribution network are eligible for an avoided TUoS payment that reflects the value of the avoided peak demand at the transmission connection had the generator not been in place.

The avoided TUoS benefit can be included in the non-network proposal business case for embedded generation or storage systems. CitiPower and Powercor's calculation methodology for avoided TUoS payments are shown in Appendix B:

6. Connecting Embedded Generators

In order for an embedded or micro embedded generator to safely connect to a distribution network, a connection assessment process that results in a connection agreement is a prerequisite. Detailed processes for both Embedded Generation and Micro Embedded Generation are covered under Chapter 5 and Chapter 5A of the NER.

Basic connections under Chapter 5A are more flexible and shorter than Chapter 5 and are covered in detail in published connection policies on our website for CitiPower and Powercor.

This chapter sets out the high-level process for lodging an application to connect an HV embedded generator which exceeds the exemption limit (currently 5MW) for registration as a participant with AEMO. The NER contains detailed requirements in terms of process, timeframes and information provision for connections. Broadly speaking the connection process involves:

- Enquiry process: A two stage process consisting of a preliminary enquiry stage followed by a detailed enquiry stage in order to understand the practice of making a connection in the chosen location; and
- Application process: Following the enquiry stages, an embedded generator proponent may lodge a full application to connect with a distributor, and the distributor will define the works required to enable the connection and ultimately issue an offer to connect.
- Connection agreement: As part of acceptance of an offer to connect, a formal connection agreement will be negotiated and signed.

The process is shown in the diagram below.

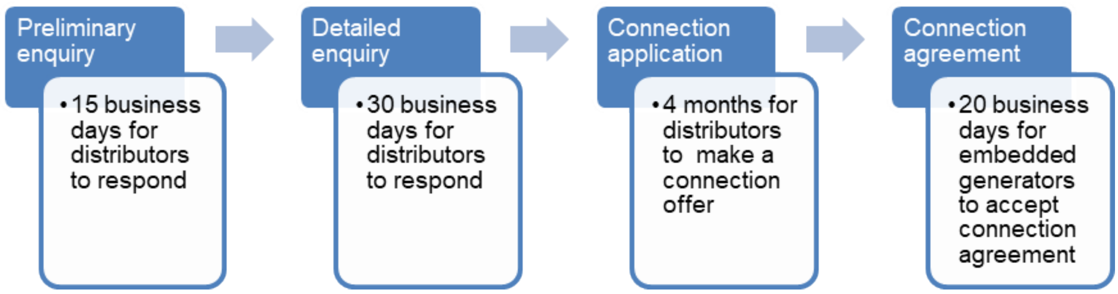

Figure 2: Connection Process for Embedded Generators under Chapter 5.3 of the NER

Excluding the time taken by embedded generator proponents to provide information, the rule 5.3A process may take approximately 25 weeks.

Connection charges are to be negotiated in good faith between the distributor and proponent as part of the process and the connection offer must:

- contain an itemised statement of connection costs in any connection offer
- be fair and reasonable
- entitle the distributor and the connection applicant to negotiate, which must be conducted in good faith; and
- contain the terms and conditions of the kind set out in schedule 5.6 of the NER.

An offer to connect must define the basis for determining the distribution service charges in accordance with chapter 6 of the NER, including the prudential requirements in part K of chapter 6.

An offer to an embedded generator must conform with the access arrangements set out in rule 5.5 of the NER. This includes additional requirements in terms of the connection offer, including:

- reaching agreement on the compensation to be provided by the distributor to the embedded generator, or vice versa, in the event that they are constrained on or off during a trading interval
- the maximum negotiated use of system charges applied by the distributor must be in accordance with the applicable requirements of chapter 6 of the NER and the negotiated distribution service criteria applicable to the distributor; and
- a distributor must pass through the locational component of prescribed TUOS charges that would have been payable by the distributor to a transmission company had the connection applicant not connected to the network.

Further details regarding the factors that CitiPower and Powercor take into account when assessing an application, or in negotiating a connection agreement, such as the technical requirements, are found in the connection guidelines available from the CitiPower and Powercor websites.

7. Further Information

7.1 Additional Reports, Policies and Information

Table 2: Links for Further Information

Topic	CitiPower	Powercor
Distribution Annual Planning Report	DAPR - CitiPower & Powercor	
Transmission Annual Planning Report	TCPR	
RIT-D’s & RIT-T’s	RIT-D & RIT-T's - CitiPower & Powercor	
Network Visualisation Portal	CitiPower/Powercor - Rosetta Network Visualisation Portal	
Piclo Flex Marketplace	Piclo Flex	
Non-Network Opportunities	Non-network opportunities - CitiPower & Powercor	
Connection for Embedded Generators	Embedded Generators - CitiPower & Powercor	
Connection Policy	Connection Policy - CitiPower	Connection Policy - Powercor

7.2 Contact Details

Should you have any queries or require further information relating to the contents of this report, please contact:
dminterestedparties@powercor.com.au

For other enquiries, please contact:

- CitiPower Customer Service
  - General Enquiries: 1300 301 101
- Powercor Customer Service
  - General Enquiries: 13 22 06
  - Website www.powercor.com.au

Appendix A: National Electricity Rules Requirements

Under the National Electricity Rules (NER) Clause 5.13.1 (h) this demand side engagement strategy must include the following information, as set out in Schedule 5.9 of the NER:

a) a description of how the Distribution Network Service Provider will investigate, develop, assess and report on potential non-network options.

b) a description of the Distribution Network Service Provider's process to engage and consult with potential non-network providers to determine their level of interest and ability to participate in the development process for potential non-network options.

c) an outline of the process followed by the Distribution Network Service Provider when negotiating with non-network providers to further develop a potential non-network option.

d) an outline of the information a non-network provider is to include in a non-network proposal, including, where possible, an example of a best practice non-network proposal.

e) an outline of the criteria that will be applied by the Distribution Network Service Provider in evaluating non-network proposals.

f) an outline of the principles that the Distribution Network Service Provider considers in developing the payment levels for non-network options.

g) a reference to any applicable incentive payment schemes for the implementation of nonnetwork options and whether any specific criteria is applied by the Distribution Network Service Provider in its application and assessment of the scheme.

h) the methodology to be used for determining avoided Customer TUOS charges, in accordance with clauses 5.4AA and 5.5; and.

i) a summary of the factors the Distribution Network Service Provider considers when negotiating connection agreements with Embedded Generators.

j) the process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of connection agreements for embedded generating units.

k) the process for lodging an application to connect for an embedded generating unit and the factors considered by the Distribution Network Service Provider when assessing such applications.

l) worked examples to support the description of how the Distribution Network Service Provider will assess potential non-network options in accordance with paragraph (a).

m) a link to any relevant, publicly available information produced by the Distribution Network Service Provider.

n) a description of how parties may be listed on the demand side engagement register; and

o) the Distribution Network Service Provider's contact details.

Appendix B: Avoided TUoS Calculation

This Appendix sets out the current method that Powercor and CitiPowerwill use to calculate avoided TUoS payments for eligible embedded generators.

Step 1: Determination of calculation period

The avoided TUoS calculations for eligible embedded generators (EGs) mirror the calculation of TUoS locational charges as per AEMO's TUoS pricing methodology[1] using the 365-day method.

Calculation relies upon defining two annual period, namely:

- Year t: Being the financial year of the locational pricing used in avoided TUoS calculations and the year in which the avoided TUOS payment is to be made; and
- Year t-2: Being the financial year two years prior to Year t, which represents the most recent Financial year where full historical data is available for the calculation of maximum demands.
- *where financial year period is from the 1st of July to the 30th of June*

Example: If the locational prices being applied are for the year FY2024/25, the maximum demands used will be from the year FY2022/23 and the avoided TUOS payment will be made in FY2024/25

Step 2: Collection of data

As per the 365-day methodology, the avoided TUoS will be calculated using the 12 maximum monthly demands (MDs) for the year t-2. The 30-min interval demand meter data (MW) is extracted by us for each embedded generator for the year. AEMO sends us the following:

3. maximum monthly demand (MW) and corresponding 30-min period for the same year for each terminal station (TS)
4. 30-min interval demand data for the same year for each TS

Step 3: Calculation of avoided TUoS payments

The steps below apply to each eligible EG on our network using the "with/without" calculation methodology

3a. "With" the EG connected

- Identify the actual monthly MDs (MW) at the TS the EG is connected to using the 30-min interval demand data sent by AEMO for the year t-2
- Calculate the average of the 12 MDs identified above
- Calculate the TUoS charge ($) using the locational price ($/MW) set by AEMO for the year t

"With" Locational TUoS charge$_t$ = locational price$_t$ x average(12 monthly actual MDs)$_{t-2}$

3b. "Without" the EG being connected

- We need to assume that the EG was not connected to our network and to account for this, we need to add the export stream data (MW) the TS level data sent by AEMO for each 30-min interval
- Identify the monthly MDs (MW) at the TS level from the set of demand data obtained above
- Calculate the average of the 12 MDs identified above
- Calculate the TUoS charge ($) using the locational price ($/MW) set by AEMO for the year t

"Without" Locational TUoS charge$_t$ = locational price$_t$ x average(12 monthly MDs if EG did not exist)$_{t-2}$

3c. Avoided TUoS payment

- Calculate the difference between the locational TUoS charges calculated in steps 3a and 3b which is the avoided TUoS payment that the EG is eligible for

[1] Pricing Methodology for Prescribed Transmission Services - 1 July 2022 to 30 June 2027

Avoided TUoS payment$_t$ = “Without” Locational TUoS charge$_t$ - “With” Locational TUoS charge$_t$

Avoided TUoS Shared Benefit: Where contractual agreements exist for sharing of avoided TUoS payments, the avoided TUoS amount will be apportioned as specified by the contract.

EG connected to multiple terminal stations: Where the embedded generator is connected to the distribution network in a location that is serviced by multiple TSs, the usage ratio between the TSs is applied to the avoided TUoS payment calculated