RIT-D: Mount Cottrell Sub-Transmission Capacity Limitation – Options Screening Report

Powercor Australia Ltd

August 2026

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1. Executive summary

1.1 Summary

Powercor Australia Ltd (**Powercor**) is a regulated Victorian electricity distribution business. Powercor supplies electricity across 64 per cent of Victoria, spanning from the western suburbs of Melbourne through central and western Victoria to the South Australian and New South Wales borders, servicing 945,000 customer connections.

The Powercor electricity distribution network consists of more than 602,760 poles and over 77,438 kilometres of overhead lines and underground cables. Electricity is received via 138 sub-transmission lines at 155 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The regulatory investment test for distribution (**RIT-D**) is an economic cost-benefit assessment and consultation process designed to identify the credible option that addresses an identified need on the network, while maximising net economic benefits for stakeholders in the National Electricity Market (**NEM**) – the preferred option.

The area of Powercor's electricity distribution network that is the subject of this RIT-D is the Mount Cottrell supply area. It comprises major load customers, supplied from a network of 66 kV sub-transmission lines from the Altona West (**ATS West**) Terminal Station.

We are forecasting capacity limitations within these sub-transmission lines, limiting our ability to supply the anticipated growth in electricity demand from our major customers located within the Mount Cottrell supply area. This could lead to a deterioration in electricity supply reliability, with load curtailments and forced outages.

In response to this identified need, we have identified a range of potential credible options to address the emerging sub-transmission network limitations. Given the total cost of the most expensive credible network option is greater than the RIT-D trigger threshold of $7 million[1], we have initiated a RIT-D consultation process.

1.2 The identified need

The identified need for the RIT-D is to address the forecast deterioration in electricity supply reliability within the Mount Cottrell supply area. This is triggered by forecast increases in maximum electricity demand by major customer loads exceeding the sub-transmission network capacity of the supply area.

The forecast sub-transmission network capacity limitations and reliability implications for the Mount Cottrell supply area are summarised in Table 1.

Table 1: Network capacity limitations and reliability implications for Mount Cottrell supply area

Year	Network capacity shortfall (MVA)	Expected unserved energy (MWh pa)
2026	0	0.0
2027	2	0.2
2028	82	110

[1] 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER), 2024.

2029	110	675
2030	134	1,008
2031	148	38,646
2032	151	63,244
2033	151	63,259

Based on the current demand forecasts, material reliability impacts are expected from 2028, with rapid escalation thereafter. We have identified that approximately 82 MVA of additional capacity is required by 2028, increasing to 151 MVA by 2032, through network augmentation or alternative non-network approaches is required to maintain a reliable supply of electricity to the Mount Cottrell supply area.

1.3 Potential credible options

Solutions to the identified need are required to manage and mitigate the forecast deterioration in electricity supply reliability, to maintain reliability of electricity supply to our customers.

We propose to investigate and evaluate the following three options to address the identified need:

- Option 1: new 132/66kV zone substation and 132 kV sub-transmission lines
- Option 2: new 66kV switching substation and 66 kV sub-transmission lines
- Option 3: non-network or stand-alone power system (**SAPS**) solutions.

We do consider generation within the Mount Cottrell supply area under Option 3 as a potential credible solution, to either avoid, reduce in scope or defer the credible network options being considered. We are therefore seeking a market response (as part of this consultation) to assess any solutions alongside network Options 1 and 2.

1.4 Submissions and next steps

This Options Screening Report (**OSR**) has been prepared in accordance with clause 5.17.4, paragraphs (b) to (h) of the *National Electricity Rules* (**NER**)2 version 243 and section 4.2 of the *RIT-D Application Guidelines*3.

Publication of the OSR is the first stage of the RIT-D consultation process for investigating and assessing whether there are potential credible alternative network, non-network or SAPS solutions available as alternatives to, or supplements for the network options that address the identified need.

We welcome written submissions on the credible options presented in this OSR. Proposals are invited from proponents of potential non-network or SAPS options (stand-alone or in conjunction with a network solution) that address the identified need. Credible alternative options will be assessed alongside network options at the next stage of the RIT-D process.

Submissions should be emailed to:

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Manager Sub-transmission Planning and Major Connections
Email: ritdenquiries@powercor.com.au

[2] National Electricity Rules (NER) | Australian Energy Market Commission (AEMC), 2026.

[3] Regulatory Investment Test for Distribution application guidelines | Australian Energy Regulator (AER), 2024.

on or before 11 November 2026.

In the subject field, please reference '**RIT-D Mount Cottrell Sub-Transmission Capacity Limitation**'.

We prefer that submissions be published on our website and the Australian Energy Market Operator's (**AEMO**) website. If you do not want your submission to be published, please clearly stipulate this at the time of lodgement.

Assessments of the options and responses to this OSR will be published in a *Draft Project Assessment Report* (**DPAR**), the second stage of the consultation process, as required under NER clause 5.17.4, paragraphs (i) to (m), and section 4.3 of the *RIT-D Application Guidelines*.

We expect to publish the DPAR before the end of December 2026.

2. Definitions

Table 2: Terms and definitions

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATS West	Altona (West) Terminal Station
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EUE	Expected Unserved Energy
FPAR	Final Project Assessment Report
HTK	Major Customer Substation
MCTS	Mount Cottrell Terminal Station (future)
MD	Maximum Demand
NEM	National Electricity Market
NER	National Electricity Rules
O&M	Operations and Maintenance
OSR	Options Screening Report
RIT-D	Regulatory Investment Test for Distribution
SAPS	Standalone Power System
TCD	Major Customer Substation
TGNA	Zone (or Switching) Substation (future)
TGNA (Customer)	Major Customer Substation
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital

Term	Definition
Credible option	An option that addresses the 'identified need', is commercially and technically feasible, and can be implemented in sufficient time to meet the 'identified need'.
Identified need	Any regulatory compliance, thermal capacity, voltage, or safety limitation on the distribution system.
Limitation	Any limitations on the operation of the distribution system that will give rise to regulatory non-compliance, expected unserved energy, or safety risk consequences.
Network option	A means by which an 'identified need' can be fully or partly addressed by expenditure on distribution network assets.
Non-network or SAPS option	A means by which an 'identified need' can be fully or partially addressed other than by a network option.
Non-network service provider	A party who provides a non-network or SAPS option.
Potential credible option	An option has the potential to be a credible option based on an initial assessment of its ability to address the 'identified need'.
Preferred network option	A credible network option that maximises the present value of net economic benefit in the NEM. The preferred network option can be a network option, or do nothing (i.e. status quo). For regulatory compliance needs, the least lifecycle cost network option.
Preferred option	A credible option that maximises the present value of net economic benefit in the NEM. The preferred option can be a network option, non-network or SAPS option, combination of both, or do nothing. For regulatory compliance needs, the least lifecycle cost option.

3. Introduction

We are a regulated Victorian electricity distribution business. We supply 64 per cent of Victoria spanning from the western suburbs of Melbourne through central and western Victoria to the South Australian and New South Wales borders, to 945,000 customer connections.

Our electricity distribution network consists of more than 602,760 poles and over 77,438 kilometres of overhead lines and underground cables. Electricity is received via 138 sub-transmission lines at 155 zone substations, where it is transformed from sub-transmission voltages down to distribution voltages.

The RIT-D is an economic cost-benefit assessment and consultation process designed to identify the credible option that addresses an identified need on the network, while maximising net economic benefits for stakeholders in the NEM – the preferred option.

The area subject to this RIT-D is the Mount Cottrell supply area, comprising of major customer loads, supplied from a network of 66 kV sub-transmission lines from ATS West Terminal Station.

We are forecasting capacity limitations within these sub-transmission lines, limiting our ability to supply the anticipated growth in electricity demand within the Mount Cottrell supply area. This could lead to a deterioration in electricity supply reliability, with load curtailments and forced outages.

In response to this identified need, we have identified a range of potential credible options to address the emerging sub-transmission network limitations. Given the total cost of the most expensive credible network option is greater than the RIT-D trigger threshold of $7 million[4], we have initiated a RIT-D consultation process.

This OSR has been prepared in accordance with the requirements of clause 5.17.4, paragraphs (b) to (h) of the NER[5] version 243 and section 4.2 of the *RIT-D Application Guidelines*[6].

Publication of the OSR is the first stage of the RIT-D consultation process for investigating and assessing whether potential credible alternative network, non-network or SAPS solutions are available to, or supplement, the network options presented in this OSR, that address the identified need.

This OSR sets out:

- the identified need we are seeking to address, together with the assumptions used in identifying this need
- a description of the potential credible network options that may address the identified need
- the technical characteristics of each potential credible option
- the estimated construction timetable and commissioning date
- the total indicative capital and operating costs for each potential credible option and a high-level cost breakdown
- the technical characteristics of the identified need that a non-network or SAPS option would be required to provide
- information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a proposal for consideration by the RIT-D proponent.

[4] 2024 cost thresholds review for the regulatory investment test | Australian Energy Regulator (AER), 2024.
[5] National Electricity Rules (NER) | Australian Energy Market Commission (AEMC), 2026.
[6] Regulatory Investment Test for Distribution application guidelines | Australian Energy Regulator (AER), 2024.

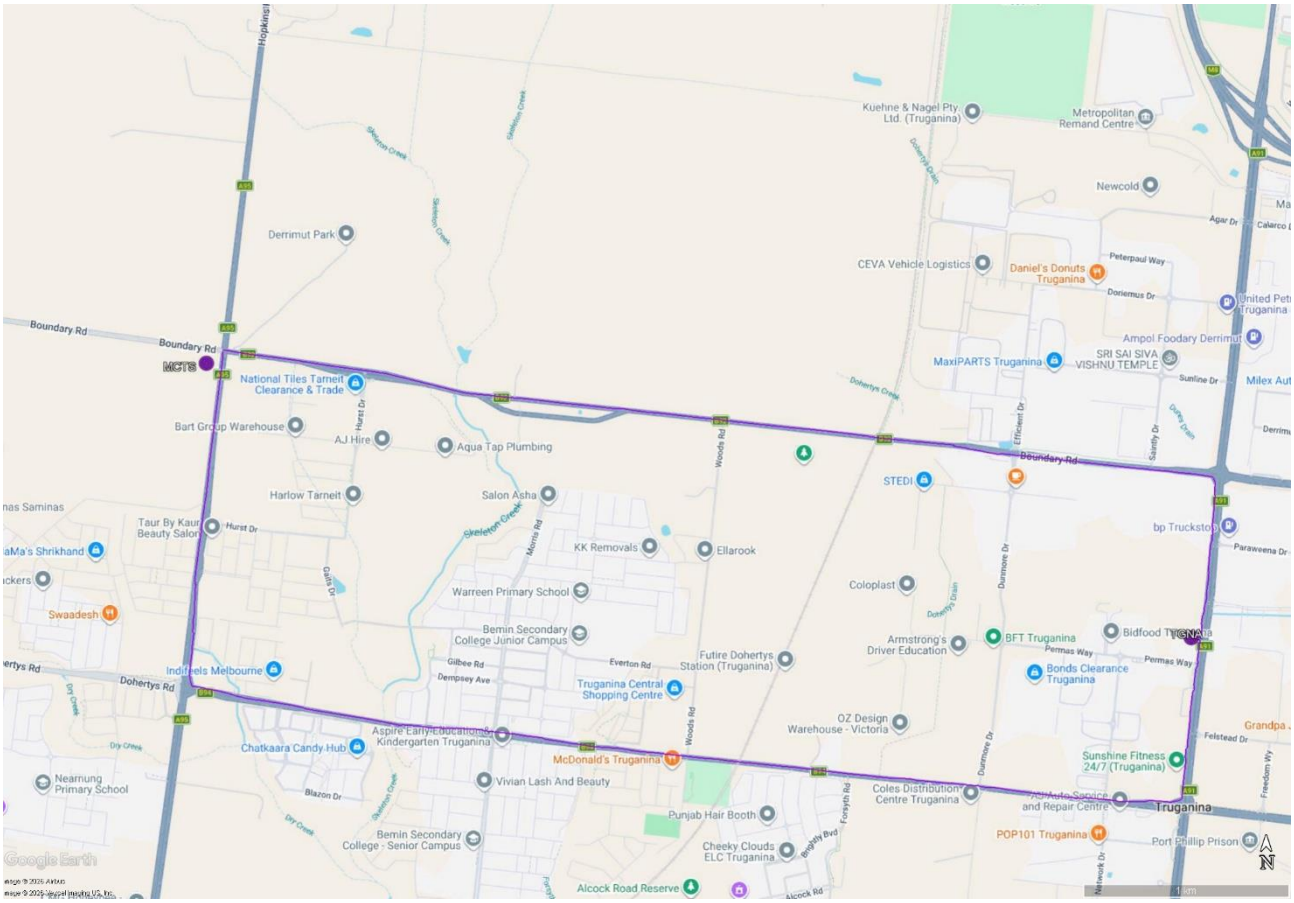
4. Identified need

This section presents the identified need of this RIT-D, and the assumptions in quantifying the identified need.

4.1 Network overview

The Mount Cottrell supply area, located in Melbourne's outer-western metropolitan area, is currently serviced by a network of existing 66 kV sub-transmission lines supplied from ATS West. The Mount Cottrell supply area is shown in Figure 1.

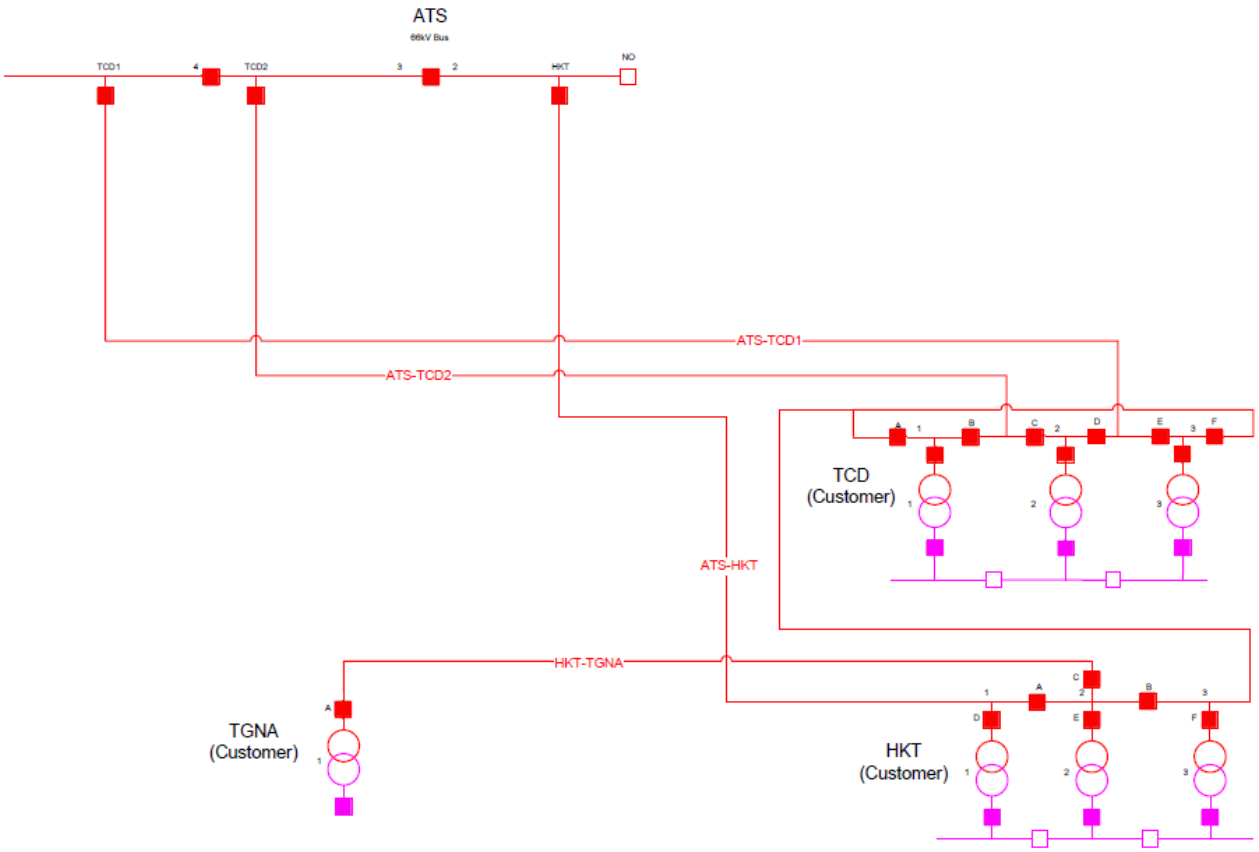
Figure 1: Map of Mount Cottrell supply area



We have received several new connection applications for large customer loads within the Mount Cottrell supply area. The size of the load being proposed to be connected would cause the existing 66 kV sub-transmission network in the area to become overloaded, even if only one of those new large connections achieved full load.

The new large customer connections are currently under construction or at completion, with load scheduled to be ramped up over the coming years. All customers are being connected to the existing 66 kV sub-transmission network as shown in Figure 2.

Figure 2: Existing sub-transmission network connections of large customer loads



4.2 Description of the identified need

The aggregated coincident maximum demand of these large customer loads is presently 55 MVA. This is expected to double within the next year, rising to more than 300 MVA by the end of the decade. This will present overload (load-at-risk) conditions on the sub-transmission network under single contingency (N-1) and system normal (N) conditions, where the forecast maximum demand begins to exceed the associated network rating.

The forecast overload on the existing ATS-TCD-HTK/TGNA-ATS 66 kV sub-transmission network is expected to occur in 2028 under single contingency (N-1) conditions, and after 2033 under system normal (N) conditions, as shown in Table 3.

Table 3: Forecast overload levels (load-at-risk) on ATS-TCD-HTK/TGNA-ATS 66 kV sub-transmission network

Year	N-1 (MVA)	N (MVA)
2026	0	0
2027	0	0
2028	24	0
2029	69	0
2030	102	0
2031	127	0
2032	132	0

2033	135	0

The forecast overload on the existing HTK-TGNA 66 kV line is expected to occur in 2027 under single contingency (N-1) conditions, and in 2031 under system normal (N) conditions, as shown in Table 4.

Table 4: Forecast overload levels (load-at-risk) on HTK-TGNA 66 kV sub-transmission line

Year	N-1 (MVA)	N (MVA)
2026	0	0
2027	2	0
2028	82	0
2029	110	0
2030	134	0
2031	148	12
2032	151	15
2033	151	15

With these forecast overloads comes a deteriorating level of electricity supply reliability. Under current demand forecasts, material reliability impacts are expected from 2028, with rapid escalation thereafter.

We utilise a probabilistic planning approach to assess whether it is economic to invest in risk mitigation to reduce the forecast deterioration in electricity supply reliability. This is represented using a calculated value of expected unserved energy (**EUE**).

The identified need for this RIT-D is to address the forecast deterioration in electricity supply reliability within the Mount Cottrell supply area, triggered by forecast increases in maximum electricity demand exceeding the sub-transmission network capacity of the supply area.

Solutions to the identified need are required to manage and mitigate the forecast increases in EUE, to maintain reliability of electricity supply to our customers.

4.3 Quantification of the identified need

We have identified that approximately 82 MVA of additional capacity is required by 2028, rising to 151 MVA by 2032, through network augmentation or alternative non-network approaches (such as demand management, generation, and storage) to maintain a reliable supply of electricity to the Mount Cottrell supply area.

We have calculated the EUE by determining the amount of energy that would not be able to be supplied by the existing 66 kV sub-transmission network under system normal conditions. We calculate the EUE by using the maximum demand forecast for the network and multiplying it by its normalised load duration curve to determine the energy at risk, based on the amount of time that the forecast load is above the (N) rating, considering the load transfer capacity.

We have calculated the EUE by determining the amount of energy that would not be able to be supplied by the sub-transmission network under single contingency conditions. The calculation differs from that of the above by instead using the (N-1) rating and multiplying the overall result by the sub-transmission line unavailability, which considers failure rate and restoration time.

The total EUE is weighted according to 30 per cent of the EUE calculated using a 1-in-10 year (**PoE10**) maximum demand, and 70 per cent of the EUE calculated using a 1-in-2 year (**PoE50**) maximum demand. The components of the network limitations contributing to the forecast EUE are shown in Table 5 and Table **6**.

Table 5: Forecast EUE for ATS=TCD-HTK/TGNA-ATS

Year	N (MWh)	N-1 (MWh)
2026	0	0
2027	0	0
2028	0	94.0
2029	0	650
2030	0	979
2031	0	1,224
2032	0	1,276
2033	0	1,292

Table 6: Forecast EUE for HTK-TGNA

Year	N (MWh)	N-1 (MWh)
2026	0	0
2027	0	0.2
2028	0	15.9
2029	0	25.4
2030	0	29.6
2031	37,389	33.2
2032	61,934	33.2
2033	61,934	33.2

The cost of deteriorating reliability to the community is determined by multiplying the total EUE by the value of customer reliability (**VCR**). We have calculated the locational VCR by adopting the AER's 2024 VCRs[7] for the different customer segments, weighting them by the mix of customers' annual energy consumption localised, for each relevant network asset. The VCR we have used is $37,370 per MWh.

The aggregate of the sub-transmission network capacity limitations contributing to the forecast EUE and its value is listed in Table 7.

Table 7: Total forecast EUE

Year	EUE (total) (MWh pa)	Value of EUE (total) ($ million, real, 2025)
2026	0.0	0.0
2027	0.2	0.0
2028	110	3.8
2029	675	23.2
2030	1,008	34.7

[7] Values of Customer Reliability - Final report, Australian Energy Regulator (AER), 2024.

2031	38,646	1,328
2032	63,244	2,174
2033	63,259	2,174

By 2033, the EUE and its financial impact on customers is forecast to rise to 63,259 MWh p.a. and $2,174 million (real, 2025) respectively. This presents a material deterioration in electricity supply reliability.

4.4 Assumptions underpinning the identified need

Key factors underpinning the quantification of the identified need in this RIT-D include:

- forecast maximum demand
- load-duration curves
- asset ratings
- asset unavailability
- load transfer capacity.

4.4.1 Forecast maximum demand

In the absence of material changes in our forecast maximum demand, the forecast maximum demands intended to be applied for this RIT-D are those provided in Table 8 Table 9. Cells highlighted in **red** indicate a single contingency (N-1) overload condition, and those in **bold underline red** indicate a system normal (N) overload condition.

Table 8: Forecast maximum demand of ATS-TCD-HTK/TGNA-ATS 66 kV sub-transmission network

Year	Summer (MVA)	Winter (MVA)
2026	50	55
2027	100	114
2028	185	214
2029	249	258
2030	278	292
2031	307	310
2032	312	315
2033	315	315

The forecast maximum demand on the existing ATS-TCD-HTK/TGNA-ATS 66 kV sub-transmission network is expected to exceed its single contingency (N-1) rating in 2028 and reaches its system normal (N) rating from 2033.

Table 9: Forecast maximum demand of HTK-TGNA 66 kV sub-transmission line

Year	Summer (MVA)	Winter (MVA)
2026	0	0
2027	0	2
2028	55	82
2029	109	110
2030	121	134
2031	**147**	**148**
2032	**150**	**151**
2033	**150**	**151**

The forecast maximum demand on the existing on the HTK-TGNA 66 kV line is expected to exceed its single contingency (N-1) rating in 2027 and exceed its system normal (N) rating in 2031.

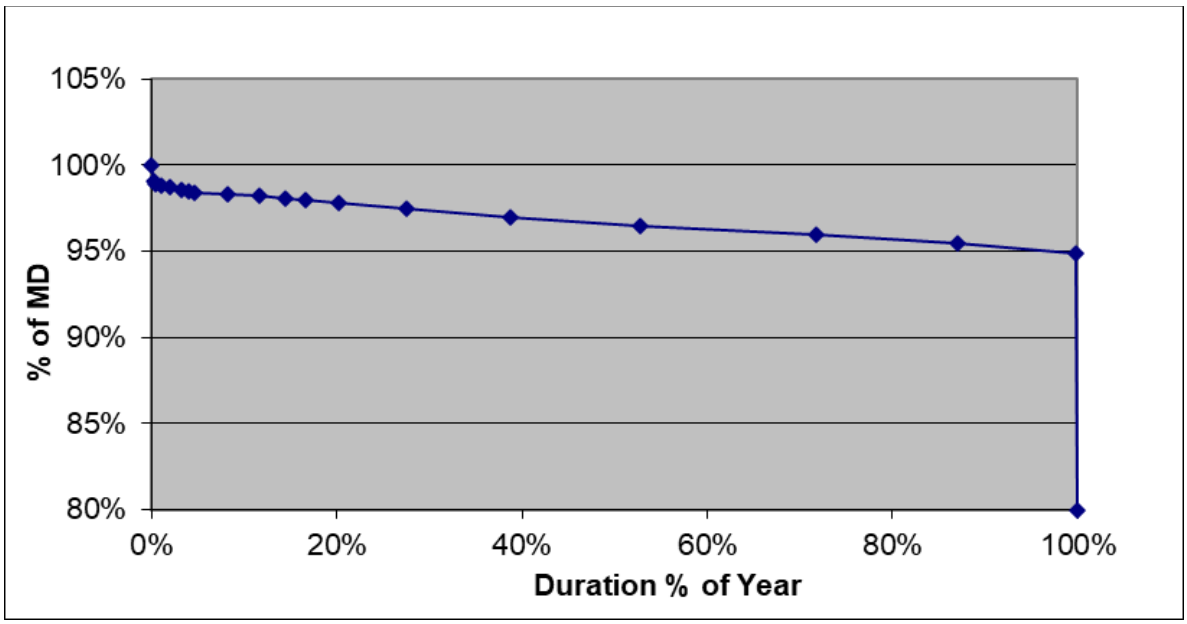
Power factor, for the purposes of this RIT-D, can assumed to be unity at the sub-transmission network level.

4.4.2 Load-duration curves

Load-duration curves plot demand, normalised as a percentage of the maximum demand, against the cumulative percentage of time within a year. Demand values are ordered in descending magnitude, such that each point on the load-duration curve represents the proportion of the year for which demand is expected to be greater than or equal to the corresponding load level. Where the product of the load-duration ordinate and the forecast seasonal maximum demand exceeds the seasonal rating, the excess portion, represented by the area above the rating, contributes to EUE.

Figure 3 illustrates that the large customer loads in aggregate for the Mount Cottrell supply area have a very high load factor of 96 per cent.

Figure 3: Load-duration curve of large customer loads



4.4.3 Asset ratings

The sub-transmission line ratings intended to be applied in this RIT-D are those listed in Table 10.

Table 10: Ratings of 66 kV sub-transmission network components

Line	Summer (MVA)	Winter (MVA)
ATS-HTK (N)	135	142
ATS-TCD1 (N)	135	142
ATS-TCD2 (N)	135	142
ATS=TCD-HTK/TGNA-ATS (N)	315	330
ATS=TCD-HTK/TGNA-ATS (N-1)	180	190
HTK-TGNA (N)	135	142
HTK-TGNA (N-1)	0	0

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4.4.4 Asset unavailability

For this RIT-D, sub-transmission line failure rates are assumed to be 5 per cent per km per annum, with repair times of 12 hours per failure event. Sub-transmission line lengths from the terminal station to the load centres being approximately 6 km in all network options.

4.4.5 Load transfer capacity

The load transfer capacity for the sub-transmission network supplying the major customer loads in the Mount Cottrell supply area is assumed to be zero for the entire forecast period.

5. Potential credible options

We have developed a set of potential credible options to address the sub-transmission network capacity limitations relating to the Mount Cottrell supply area identified need.

To address the identified need, credible options would be required to allow us to maintain electricity supply reliability for the Mount Cottrell supply area, having a capability to meet the forecast maximum demand without overloading the network assets.

Table 11 provides a summary of the base case option.

Table 11: Base case

Option	Description
Do nothing (status quo)	This base case option involves no additional investment. This option does not address the identified need. Customers over time, are increasingly likely to experience a deterioration in their supply reliability, or may have their electricity demand curtailed, to avoid overloading the network.

To address the anticipated network capacity limitations in the Mount Cottrell supply area, we consider the following solutions could be implemented to mitigate the forecast electricity supply reliability deterioration, as shown in Table 12.

Table 12: Credible options under consideration

Option	Description
Option 1 New 132/66kV zone substation and 132 kV sub-transmission lines	This option establishes a new 132/66 kV zone substation (TGNA) with 3 x new 132/66 kV 250 MVA transformers, three new 66 kV buses, and 3 x new 132 kV 360 MVA sub-transmission lines (refer to description in section 8.2) by the 2027-28 summer season. The construction time is 2 years. The net capital cost of this option is $16.51 million (real, 2025)[8]. Operating costs are expected to be $0.2 million per annum. The 10-year present value of all costs (capital, O&M) is $15.7 million (real, 2025). This option addresses the identified need in its entirety.
Option 2 New 66kV switching substation and 66 kV sub-transmission lines	This option establishes a new 66 kV switching substation (**TGNA**) with 5 x new 66 kV buses (ring), and 5 x new 66 kV 180 MVA sub-transmission lines (refer to description in section 8.2) by the 2027-28 summer season. The construction time is 2 years. The net capital cost of this option is $20.51 million (real, 2025)[9]. Operating costs are expected to be $0.2 million per annum. The 10-year present value of all costs (capital, O&M) is $19.5 million (real, 2025).

[8] Total capital cost is $117.13 million, with a customer contribution of $100.62 million and a net capital cost of $16.51 million (Real, 2025).

[9] Total capital cost is $121.13 million, with a customer contribution of $100.62 million and a net capital cost of $20.51 million (Real, 2025).

	This option addresses the identified need in its entirety but is more expensive than Option 1 because two sub-transmission lines will need to be underground for parts of the route length.

Option 3
Non-network and SAPS solutions
	The *RIT-D Guidelines*[10] require a RIT-D proponent to screen for non-network and SAPS options. The Guidelines list the following examples of non-network options that should be considered:
	• measures or programs targeted at reducing peak demand, including:
	  ○ improvements to or additions of automatic control schemes such as direct load control
	  ○ energy efficiency programs or a demand management awareness program for consumers
	  ○ installing smart meters with measures to facilitate cost-reflective pricing.
	• increased local or distributed generation/supply options, including:
	  ○ capacity for standby power from existing or new embedded generators
	  ○ using energy storage systems, load transfer capacity and more.
	We consider that generation within the Mount Cottrell supply area under Option 3 is a potential credible solution, to either avoid, reduce in scope or defer the credible network options being considered. We therefore seek market responses (as part of this consultation) to assess any solutions alongside network Options 1 and 2.
	The technical requirements of this solution are detailed in section 6.1.

[10] Regulatory Investment Test for Distribution application guidelines | Australian Energy Regulator (AER).

6. Alternative network, non-network or SAPS options

This section provides information for non-network or SAPS services that are required to address the identified need.

6.1 Required performance characteristics

Table 13 sets out the dispatchable load reduction/generation/storage capacity required from a non-network or SAPS option, located within the Mount Cottrell supply area, by year. It also provides an indication of the maximum number of operating hours per year, and the expected amount of energy needing to be supported by the option. This information (together with Figure 3) provides an indication of the required operating profile to address the identified need in its entirety, noting that prospective non-network service providers may not be able to exactly (or fully) match these requirements to be considered a credible solution.

Table 13: Performance requirements of alternative solutions

Year	Capacity required (MW)	Maximum duration (hrs pa)	Expected annual energy (MWh pa)
2026	0	0	0.0
2027	2	The duration of each sub-transmission line forced outage.	0.2
2028	82		110
2029	110		675
2030	134		1,008
2031	148	7,582	38,646
2032	151	8,739	63,244
2033	151	8,739	63,259

We understand that alternative solutions advanced by non-network proponents may be wide-ranging, each with their own benefits and limitations. Proposals that may defer network expenditure may be acceptable. We will work with non-network proponents based on the specifics of what the proponents offer and any necessary further works that we may have to undertake to ensure the reliability, security and safety of the network are maintained.

We offer some guidance as to minimum standards expected of any option:

- operational flexibility must not be compromised
- quality of supply must see voltages remain within regulatory limits and fluctuations controlled
- current reliability performance must be maintained
- contained only within the Mount Cottrell supply area to address the identified need
- implementable within the timeframes of the identified need.

6.2 Potential payments for non-network support services

At this stage, the preferred network option is yet to be determined. However, the maximum annualised capital expenditure that could be deferred by contractually engaging a non-network solution is

approximately $5.5 million per annum[11] (real, 2025), assuming Option 1 is the preferred network option. Please note that we do not represent this to be a precise deferral cost available to a non-network proponent, but it is a guide to interested parties in determining the viability of their proposal.

The payment for network support services varies according to availability, capacity, dispatch duration and firmness of the service, its ability to address the identified need, and the responses received from other non-network or SAPS proponents. The actual terms and payment for network support services will also be subject to negotiation and formalised in a network support agreement (**NSA**) between Powercor and the proponent.

6.3 Information to be included in alternative solution proposals

Non-network and SAPS service providers interested in alleviating the network limitations quantified in this report are advised to begin engagement with us as soon as possible.

We invite written submissions for alternative network, non-network and or SAPS solutions to address the identified need in this OSR from any interested parties. All submissions should include sufficient technical and financial information to enable us to undertake a comparative analysis of the proposed solutions against alternative options.

A detailed proposal (including the information listed below) should be prepared and submitted by the requested date, during the RIT-D consultation period.

Details required in a proposal include:

- name, address and contact details of the person making the submission
- name, address and contact details of the person responsible for non-network support (if different to above)
- a detailed description of the services to be provided, including:
    - size and capacity (MW/MVA/MWh)
    - location(s)
    - frequency and duration
    - type of action or technology proposed, including response / ramp rate information, where applicable
    - proposed dispatching arrangement (e.g. telephone, web-based trigger, automated means etc.)
    - availability and reliability performance details
    - period of notice required to enable dispatch of non-network support (e.g. to allow time for charging of energy storage solutions or market-based limitations)
    - proposed contract period and staging (if applicable)
    - proposed timing for delivery (including timeline to plan and implement the proposal)
    - high-level electrical layout of the proposed site (if applicable)
    - evidence and track record proving capability and previous experience in implementing and completing projects of the same type as the proposal
    - preliminary assessment of the proposal's impact on the network, including engineering network system studies and study reports
- breakdown of the lifecycle costs for providing the service, including:

[11] 4.69% regulatory WACC x $117.13 million total capital cost = $5.5 million per annum (real, 2025).

- capital costs (if applicable
- annual operating (i.e. set up and dispatch fees) and maintenance costs
- other costs (e.g. availability, project establishment, etc.)
- tariff assumptions
- expected annual payment for providing the non-network solution
- project execution strategy including design, testing and commissioning plans
- a method outlining measurement and quantification of the agreed service, including integration of the proposed solution with the network
- a statement outlining that the non-network service provider is prepared to enter into an NSA (subject to agreeing terms and conditions)
- letters of support from partner organisations
- any special conditions to be included in an NSA.

Proposals must demonstrate service capability, availability, response times, likelihood of success, and identify any limitations in that service.

Proposals must satisfy the requirements of any applicable laws, rules, and relevant regulatory authority, including following the normal network connection processes where applicable. Any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent of the non-network solution.

For further details on our process for engaging and consulting with non-network support providers, and for investigating, developing, assessing and reporting on non-network or SAPS options as alternatives to network augmentation, please refer to our Industry Engagement Strategy on our website.

7. Submissions and next steps

7.1 Submissions

We welcome written submissions on the credible options presented in this OSR. Proposals are invited from proponents of potential non-network or SAPS options (stand-alone or in conjunction with a network solution) that address the identified need. Any credible alternative options will be assessed alongside the network options at the next stage of the RIT-D process. Submissions should be emailed to:

Richard Robson (Powercor)

Manager Sub-transmission Planning and Major Connections

Email: ritdenquiries@powercor.com.au

on or before 11 November 2026.

In the subject field, please reference 'RIT-D Mount Cottrell Sub-Transmission Capacity Limitation'.

Our preference is that submissions be published on our and AEMO's website. If you do not want your submission to be made public, please clearly stipulate this at the time of lodgement.

7.2 Next steps

Assessments of the options and responses to this OSR will be published in DPAR which will initiate the second stage of consultation, as required under NER clause 5.17.4, paragraphs (i) to (m), and section 4.3 of the *RIT-D Application Guidelines*.

The DPAR will include:

- a summary of, and commentary on, any submissions on this OSR.
- a detailed market benefit assessment of the proposed credible options to address the identified need.
- identification of the proposed preferred option to meet the identified need.

We expect to publish the DPAR before the end of December 2026.

8. Appendix

8.1 OSR compliance checklist

In accordance with clause 5.17.4 of the NER, we certify that the screening for non-network and SAPS options satisfy the first stage of the RIT-D. Table 14 shows how each of these requirements have been met by the relevant section of this OSR.

Table 14: OSR compliance checklist

NER Requirement	Section
Clause 5.17.4 of the NER, Non-network options report must include the following:	
1. a description of the identified need;	Section 4
2. the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);	
3. if available, the relevant annual deferred augmentation charge associated with the identified need;	Section 6
4. the technical characteristics of the identified need that a non-network option or (in relation to a SAPS enabled network) a SAPS option would be required to deliver, such as:	
i. the size of load reduction or additional supply;	
ii. location;	
iii. contribution to power system security or reliability;	
iv. contribution to power system fault levels as determined under clause 4.6.1; and	
v. the operating profile;	
5. a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options, non-network options and (in relation to a SAPS enabled network) SAPS options.	Section 5
6. for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:	Section 5
i. a technical definition or characteristics of the option;	
ii. the estimated construction timetable and commissioning date (where relevant); and	
iii. the total indicative cost (including capital and operating costs); and	

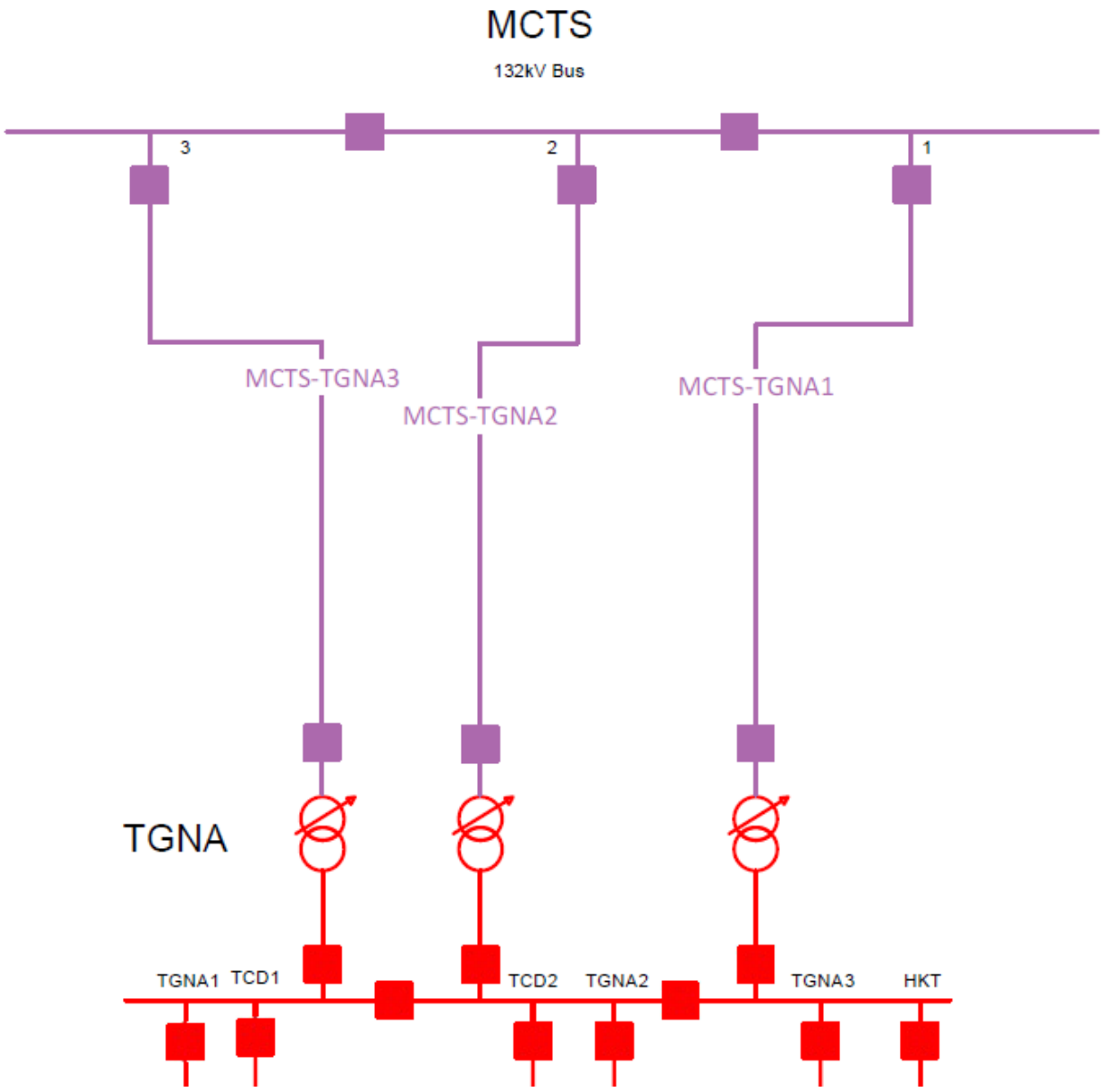
NER Requirement	Section
7. information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a non-network proposal for consideration by the RIT-D proponent.	Section 7

8.2 Proposed network options

Both the network options presented in this OSR have the new large customer connections transferred across to a new 66 kV substation, designated TGNA.

The proposed arrangement for Option 1 is shown in Figure 4, showing three new 132/66 kV transformers located at the new TGNA 132/66 kV zone substation, and three 132 kV sub-transmission lines routed back to the terminal station.

Figure 4: TGNA single line diagram



Option 2 differs in that the 132/66 kV transformers are located at the terminal station, and five 66 kV sub-transmission lines are routed from the terminal station into the new TGNA 66 kV switching substation.