Options Evaluation Report (OER)

Maintain Voltage in South Western Subsystem
OER- **N2393** revision **3.0**

Ellipse project no(s):

TRIM file: [TRIM No]

Project reason: Compliance - Regulatory obligation

Project category: Prescribed - Augmentation-Sub Sys

Approvals

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Change history

Revision	Date	Amendment
0	04/11/2021	Initial issue
1	20/12/2021	Non- network option (Option G) added; Updated the recommendations; Added references to the AEMO System Security Reports on NSCAS
2	25/07/2022	Updated for CutlerMerz comments
3	**14/10/2022**	**Updated for revised costs, discount rates and OER template.**

Executive summary

A Compliance Need has been identified to maintain the voltages of the 132 kV interconnection connecting Darlington Point and Uranquinty via Deniliquin and Finley during light demand conditions and during N-1 conditions, especially when reactive power support from Finley solar farm is not available.

As the transmission network service provider of NSW, Transgrid has the responsibility to maintain the system voltages within the maximum limits stipulated by the National Electricity Rules (NER). As stipulated by the NER Clause S5.1a.4 the voltage levels in the network are required to be maintained within ±10% of the nominal voltage.

The latest demand forecasts confirms that the minimum demand in NSW will be steadily declining over the next 20 years due to gradual and persistent growth in distributed PV generation capacity[1]. In addition, actual and expected growth in small to large-scale embedded generators connected to the Essential Energy sub-transmission network in the area is also expected to contribute to the declining minimum demand in South-western NSW.

The declining minimum demand is causing the inability to satisfactorily maintain system voltage levels within required standards leading to excessive voltages beyond the maximum allowable limit of 1.1 pu especially during the times where reactive power support is unavailable from the nearby solar farms. Further, the declining minimum demand levels and increasing embedded generator and PV generation are creating operational and planning challenges in Transgrid's ability to manage the reliability and security of the south-western 132 kV subsystem in short term, and are required to be addressed to ensure long-term stability of the network.

The expected high-voltage levels identified in practice and through the study shows that Transgrid would have a non-compliance against this requirement unless remedial action is undertaken. Currently the excessive voltages are managed through operational measures that would have a flow-on effect of reducing the supply reliability to Deniliquin and Coleambally[2].

Further, in the 2021 System Security Reports published by AEMO, an immediate NSCAS[3] gap of 2 MVAr absorbing reactive power has been declared in the Coleambally region for overnight where nearby solar farms are not available for reactive power support[4].

The assessment of the options considered to address the need appears in Table 1.

[1] Electricity Statement of Opportunities (ESOO) 2021
[2] Radialising the network would reduce the level of redundancy at Deniliquin and Coleambally from 2 to 1 hence not meeting the IPART Reliability Standard.
[3] Network Support and Control Ancillary Services (NSCAS)
[4] AEMO 2021 System Security Reports December 2021 (Version 1.0 issued 17/12/21)

Table 1: Evaluated options

Option	Description	Direct capital cost ($m)	Network and corporate overheads ($m)	Total capital cost[5] ($m)	Weighted NPV (PV, $m)	Rank
Option B	Install two (2) 10 MVAr 132 kV reactors at Deniliquin	8.8	0.9	9.7	-1.5	2
Option D	Install two (2) 11 MVAr 66 kV reactors at Deniliquin	7.7	0.8	8.5	-0.4	1

The preferred option based on the options evaluation presented in this report is expected to be Option D, as this meets the requirements of the need, is technically and economically feasible, and has the highest NPV. However, the final preferred option will be determined through the RIT-T process based on detailed network analysis, further cost/benefit analysis, technical and economic feasibility.

It is therefore recommended that the project be approved to proceed to a RIT-T assessment, with a view to the preferred option being implemented by 2024/25.

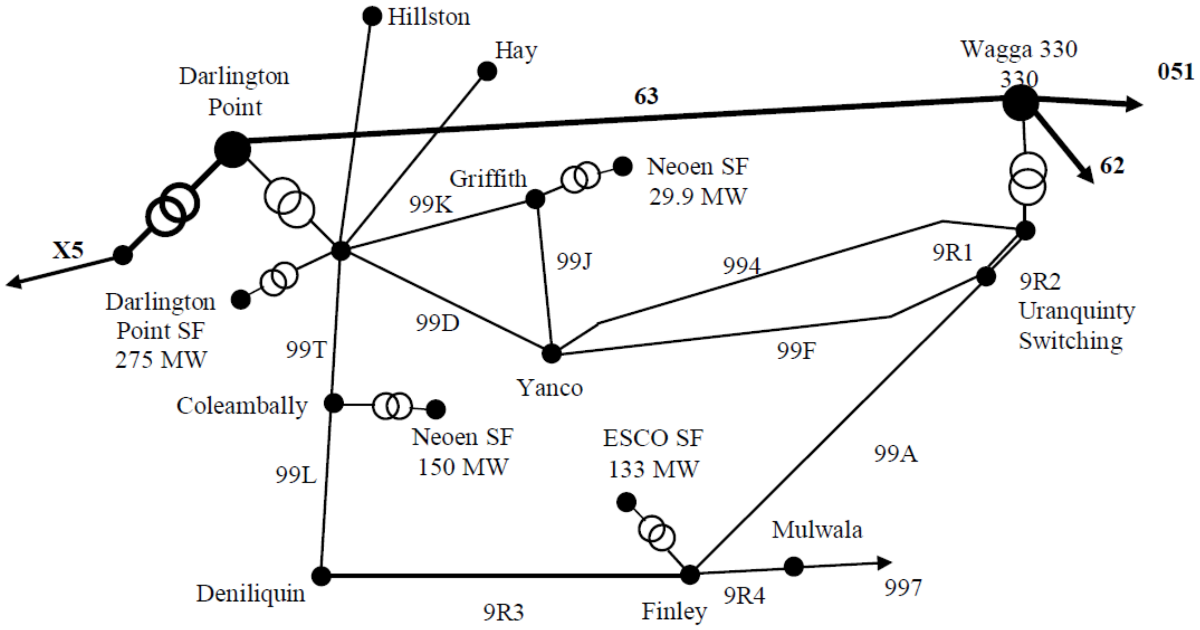
Based on the options listed in Table 1, it is expected that this project would incur a total capital cost of approximately $8.5 million in non-escalated 2021/22 dollars. This option requires up to $800k of capex to progress the project to Decision Gate 2 (DG2) which is included in the above project cost.

[5] Total capital cost is the sum of the direct capital cost and network and corporate overheads. Total capital cost is used in this OER for all analysis.

1. Need/opportunity

A Compliance Need has been identified to maintain the voltages of the 132 kV interconnection connecting Darlington Point and Uranquinty via Deniliquin and Finley under N-1 during light demand conditions, especially when reactive power support from Finley solar farm is not available. There is a requirement under the NER Clause S5.1a.4 and Transgrid System Standard to maintain the voltage levels in the network within ±10% of the nominal voltage both under N and N-1 conditions.

Figure 1: South western subsystem of the NSW transmission network



The South Western subsystem consists of 132 kV interconnection between Wagga and Darlington Point substations which parallels the Line 63, as illustrated in Figure 1. This interconnection is normally operated closed except under high-load conditions where it may have to be opened to prevent voltage collapse or thermal over loads in the interconnection under contingency conditions.

The latest demand forecasts confirms that the minimum demand in NSW will be steadily declining over the next 20 years due to gradual and persistent growth in distributed PV generation capacity over the forecast horizon[6]. In addition, actual and expected growth in small to large-scale embedded generators connected to the Essential Energy sub-transmission network in the area is also expected to contribute to the declining minimum demand in South-western NSW. The declining minimum demand is leading to the inability to satisfactorily maintain system voltage levels within required standards especially at times where reactive power support is unavailable from the nearby solar farms (night time with low demand levels or day time with low demand levels when Finley Solar Farm is not operating).

[6] Electricity Statement of Opportunities (ESOO) 2021

These factors are creating operational and planning challenges in Transgrid's ability to manage the reliability and security of the south-western 132 kV subsystem in short term, and are required to be addressed to ensure long-term stability of the network.

In April 2020, there were several events of where excessive voltage levels were occurred in the subsystem during light demand times[7,8]. During those events, correct system operation was assured against the potential over-voltages for a contingent trip of Line 99T by splitting the 132 kV subsystem through opening the 132 kV Line 9R3 at Finley. This however had the flow-on effect of reducing the supply reliability to Deniliquin and Coleambally[9]. Radialising the network would result in Level of Redundancy at Deniliquin and Coleambally to reduce from 2 to 1, hence not meeting the redundancy requirement of IPART Reliability Standard. Therefore, these operational measures are considered to be not viable to carry out in longer term to remediate the non-compliance of system voltage.

The local demand levels during these reported incidents was approximately 15% of the corresponding maximum demand level and occurred at night time whereby voltage regulation from the nearby Coleambally and Finley solar farms was not available.

Further studies carried out by Transgrid revealed that excessive voltage levels are expected at Coleambally, Deniliquin and Finley following a contingent trip (e.g. 99T, 99L, 99A) in this 132 kV interconnection (Darlington Point to Wagga via Coleambally-Deniliquin-Finley and Uranquinty). This is expected to occur when the demand levels are low and reactive power support is unavailable from the Finley Solar Farm. Reactive power support from Coleambally Solar Farm is not available under some of the contingencies noted above. The study has shown that excessive voltage levels are expected to occur during both day time and night time periods, when network loading levels are low.

Figure 2 and Figure 3 illustrate the post contingent voltages in the area under investigation for the critical contingency (99T) with the present day network configuration and based on the minimum demand forecasts.

[7] Electricity Statement of Opportunities (ESOO) 2020; Section 7.3.4 Minimum Demand Thresholds -New South Wales
[8] Transmission Annual Planning Report Transgrid, 2021
[9] Prior outage of Line 9R3 would result in loss of supply to Deniliquin BSP for a contingent trip of Line 99L or 99T.

Figure 2: Post contingent voltages for the critical contingency (trip of 99T)[10]

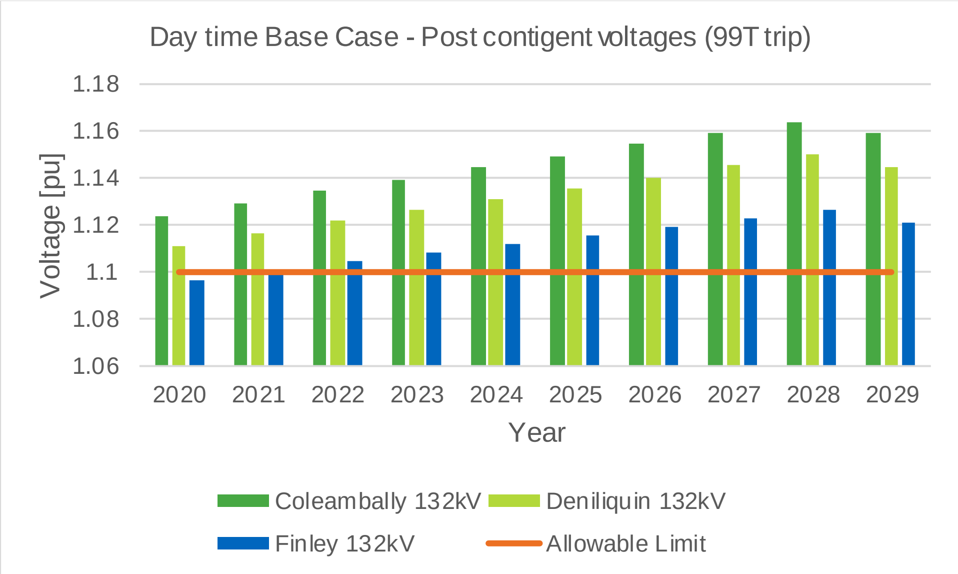
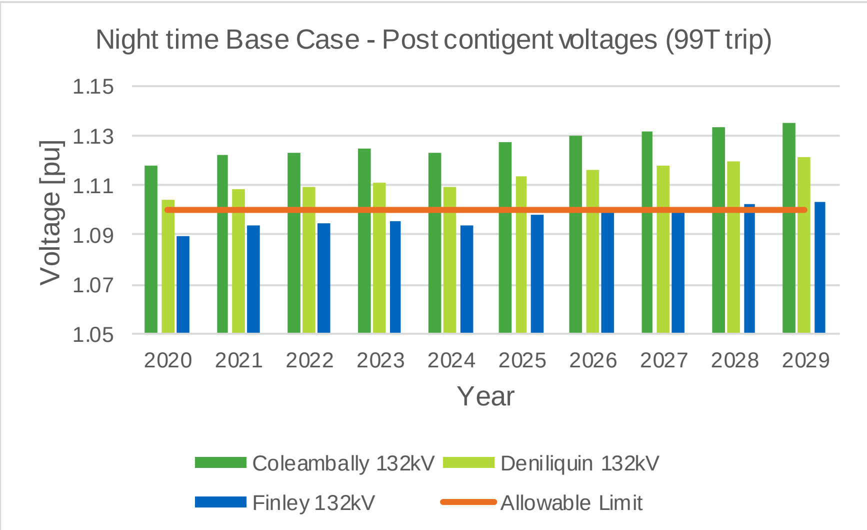


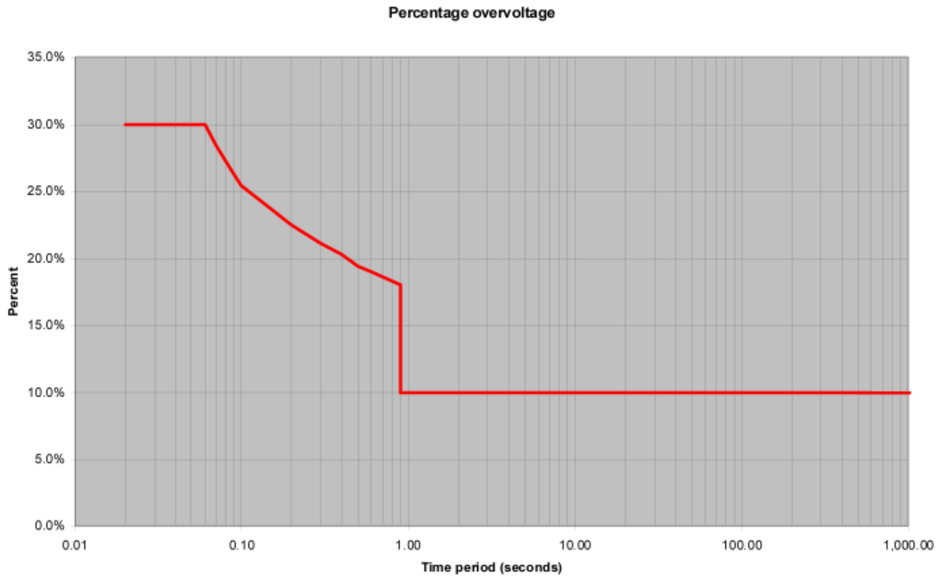
Figure 3: Post contingent voltages for the critical contingency (trip of 99T)



As the transmission network service provider of NSW, Transgrid has the responsibility to maintain the system voltages within the maximum limits stipulated by the National Electricity Rules (NER). The System standards defined under NER Clause S5.1.a.4, requires the voltage should not rise above its normal voltage by more than a given percentage of the normal voltage for a longer than the corresponding period shown in Figure 4. The expected high-voltage levels identified in practice and through the study shows that Transgrid would have a non-compliance against this requirement unless remedial action is undertaken.

[10] For a scenario where Finley Solar Farm is not generating hence reactive power support is not available

Figure 4: NER requirement of power frequency voltage (Figure S5.1a.4)



It is also to be noted that, due to the declining operational demand and uptake in PV and embedded generation, a NSCAS gap has already been identified by AEMO for South West NSW. As per the 2021 System Security Report, an immediate NSCAS gap of 2 MVAr absorbing reactive power has been declared in Coleambally area for overnight where reactive power support from the nearby solar farms is unavailable[11]. The trigger date of the identified NSCAS gap is 17 December 2021. Further, the System Security Report noted Transgrid's operational measures that are currently in place to manage post contingent voltages and Transgrid's proposed project to manage the voltage issues in the South West NSW which is the subject of this report (OER-N2393).

2. Related needs/opportunities

- Need DCN 140 – Deniliquin secondary system replacement

  Deniliquin substation has been identified for a complete secondary systems replacement due to the age and condition of the LV cable and Substation Automation Systems at the site. This project involves in replacement of the existing secondary systems using Secondary Systems Buildings (SSBs). Expected in service year: 2023/2024

- Need 0000005170 NSW-SA Interconnector (Project Energy Connect)

  This project involves establishment of the new transmission link increasing between NSW and SA. The scope of the preferred option involves building new 330 kV double circuit line from Buronga to Wagga via South of Darlington Point Dinawan) and installation of dynamic reactive plants including synchronous condensers at Buronga and Dinawan. Expected in service year: 2024/2025.

- Need 1196 Coleambally secondary System replacement

  This project involves complete in-situ secondary system renewal at Coleambally 132/33kV substation. Expected in service year: June 2023

[11] AEMO 2021 System Security Reports December 2021 (Version 1.0 issued 17/12/21)

The scope works related to the above projects will not have a major impact on the identified need. However, depending on the preferred option to be selected for the identified need, its implementation can be planned in light of these related projects during the delivery stage (e.g outage planning).

3. Options

3.1. Base case

The base case of this need is to manage the potential over voltages that could occur under N-1 condition by operational measures (radialising the network during low demand times) hence not implement a permanent solution to remediate the voltage level requirements per NER. The 132 kV link between Darlington Point and Wagga via Deniliquin may have to be radialised at low demand times (e.g opening of 9R3 at Finley) which would reduce the reliability to the customers at Deniliquin and Coleambally. The primary risk of the Transgrid continue the operational measures is that not meeting the redundancy level requirement of the IPART Reliability Standard for both Deniliquin and Coleambally during the time where the radialised operation occurs[12]. As such the loss of supply to Deniliquin and Coleambally could occur in a single contingency.

The risk of Expected Unserved Energy (EUE) associated with the radialisation is estimated for Coleambally and Deniliquin as below. The risk cost of radialisation which reflects the Base Case is calculated using the estimated EUE and the Value of Customer Reliability (VCR).

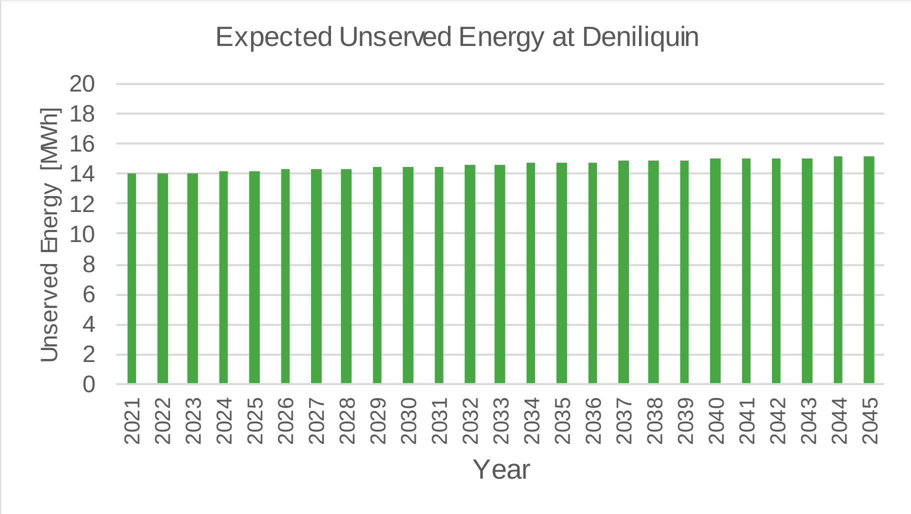
Figure 5 illustrates the yearly EUE at Deniliquin and Coleambally that could have occurred by loss of supply to the area due to the contingent trip of 99T during the radialised period of time (9R3 open at Finley). Following key parameters have been taken into account in the calculations of the EUE:

- Minimum demand forecast at Deniliquin and Coleambally
- Load profile at Deniliquin and Coleambally
- Probability of failure of 132 kV Line 99T

In addition to the reduced reliability as described above, radialisation in the Base Case may not be able to lower the voltages below 1.1pu for a foreseeable future due to the consistently declining minimum demand levels in the area.

[12] The required Level of Redundancy at Deniliquin and Coleambally is 2 and this will be reduced to 1 with the radialisation of the network.

Figure 5: Expected unserved energy at Deniliquin



3.2. Options evaluated

Option B — Install two (2) 10 MVAr 132 kV reactors at Deniliquin [NOSA N2393, OFS N2393B]

Under this option it is proposed to install two 10 MVAr 132 kV reactors at the existing Deniliquin 132/66 kV substation. In order to ensure the switching voltage step size is within the acceptable limit (<3%) it is proposed to install two (2) 10 MVAr reactors.

The scope of Option B includes:

- extend the bench by 1144 sq. meters;
- extend the fence by 92 linear metres;
- extend the cable trench by approximately 27 meters;
- extend the 132 kV busbar with rigid bus approximately 25 meters to the south;
- Install 2 x circuit breaker bays, each comprising: 1 x disconnector, 1 x dead tank circuit breaker, 1 x 3 phase high bus support, 2 x single phase low bus supports.
- Install a foundation and bund, and pipework to the oil dump tank and two (2) 10 MVAr 132 kV reactors.

The implementation of Option B effectively manages the potential over voltages in the 132 kV link hence meeting compliance requirements. Further, need for radialisation of the network and subsequent unserved energy can be avoided.

As identified in the scope, this option needs bench extension of the existing switchyard. However, no additional land will be required as the works proposed are wholly within Transgrid's property boundary. Further, as per the Option Feasibility Study, the Environmental Approval for this option requires up to 12 months. This timeframe will be reviewed as the project develops hence it is anticipated a shorter duration for the implementation may be possible than what has been indicated on the OFS.

The expected commissioning date for this option is 2024/25.

The expected expenditure profile for this option has been obtained from Transgrid's Standard Cost Estimating System and has been summarised in Table 2 below.

Table 2: Option B expected expenditure

	Total Project base Cost ($m)	2022/23 ($m)	2023/24 ($m)	2024/25 ($m)	2025/26 ($m)
Estimated Cost (un-escalated)	9.7	0.5	0.9	7.9	0.4

The estimates in Table 2 includes an uncertainty of ± 25%. Further, it is estimated that an amount up to $900k is required to progress the project from DG1 to DG2 and this cost has been included in the expenditure provided in the Table 2. This is to cover activities such as site assessments, development of concept design, the commencement of project approvals and the early procurement of long lead-time items if required.

This project is expected to be completed in an estimated 42 months following the approval of DG1.

Option D — Install two (2) 11 MVAr 66 kV reactors at Deniliquin [NOSA N2393, OFS N2393D]]

This option proposes to install two (2) 11 MVAr 66 kV reactors at Deniliquin. In order to ensure the switching voltage step size is within the acceptable limit (<3%), the option needs to be implemented by the installation of two (2) 11 MVAr 66 kV reactors as opposed to a single 22 MVAr 66 kV reactor.

The scope of this option includes:

- extend the bench by 616 sq. meters.
- extend the fence by 54 linear meters.
- extend the cable trench approximately 34 meters (two right angle bends included).
- extend the 66 kV busbar with rigid bus approximately 25 meters to the south. 2 x 3 phase bus supports will be required;
- install 2 x circuit breaker bays, each comprising: 1 x disconnector, 1 x dead tank circuit breaker, 1 x 3 phase gantry support, 2 x single phase low bus supports.
- install a foundation and bund, and pipework to the oil dump tank and two (2) 11 MVAr 66 kV reactors.

The implementation of Option D effectively manages the potential over voltages in the 132 kV link hence meeting compliance requirements. Further, need for radialisation of the network and subsequent unserved energy can be avoided.

As identified in the scope, this option needs bench extension of the existing switchyard. However, no additional land will be required as the works proposed are wholly within Transgrid's property boundary. Further, as per the Option Feasibility Study, the Environmental Approval for this option requires up to 12 months. This timeframe will be reviewed as the project develops hence it is anticipated a shorter duration may be possible than what has been indicated on the OFS.

The expected commissioning date for this option is 2024/25.

The expected expenditure profile for this option has been obtained from the Transgrid's Standard Cost Estimating System and has been summarised in Table 3 below.

Table 3: Option D expected expenditure

	Total Project base Cost ($m)	2022/23 ($m)	2023/24 ($m)	2024/25 ($m)	2025/26 ($m)
Estimated Cost (un-escalated)	8.5	0.2	1.9	5.8	0.6

The cost estimates in Table 3 includes an uncertainty of ± 25%. Further, it is estimated that an amount up to $800k is required to progress the project from DG1 to DG2 and this cost has been included in the expenditure provided in the Table 3. This is to cover activities such as site assessments, development of concept design, the commencement of project approvals and the early procurement of long lead-time items if required.

This project is expected to be completed in an estimated 42 months following the approval of DG1.

Option G — Non-network solution

This option considers the possible non-network options such as procuring reactive power from Finley solar farm via an appropriate NSCAS agreement. The reactive power support could also be procured from a potential Battery Energy Storage System (BESS).

At this stage, it is not clear whether a non-network solution will be economically viable, hence it has not been evaluated in the NPV analysis. However, the least cost network option for this Need is likely to exceed $7m and will be subject to a RIT-T. The RIT-T process will assess the viability of a non-network option.

Hence Option G is not included in the commercial evaluation undertaken as per the scope of this document.

3.3. Options considered and not progressed

Table 4: Options considered but not progressed

Option	Reason for not progressing
Option A - Install 16 MVAr reactor at Coleambally 132 kV bus	A reactor installed at Coleambally would not sufficiently improve the voltages at Deniliquin and Finley during a contingent trip of 99T hence this option is not considered technically feasible.
Option C - Reinstate the two previously installed 3 MVAr reactors, or install new two (2) 4 MVAr/11 kV reactors at Deniliquin 132/66 kV substation	Studies confirmed MVA rating of the old reactors (3 MVAr) is inadequate to alleviate the over-voltages expected under light-load conditions. If new reactors are used, the size of each reactor would have to be limited by the rating of the transformer tertiary winding (5 MVA). Hence this option is not considered to be a technically feasible option.
Option F - Upgrade the proposed Dinawan 330 kV Switching Station to a 330/132 kV Substation and build a new 132 kV connection from Dinawan to Coleambally.	Although this option has a number of benefits, compared to the other options, the investment under this option is expected to have a significantly higher capital cost due to additional primary equipment required, as Dinawan is currently only scoped to have as a 330 kV switching station. This option is technically feasible but commercially not feasible.

4. Evaluation

4.1. Commercial evaluation methodology

The economic assessment undertaken for this project includes three scenarios that reflect a central set of assumptions based on current information that is most likely to eventuate (central scenario), a set of assumptions that give rise to a lower bound for net benefits (lower bound scenario), and a set of assumptions that give rise to an upper bound on benefits (higher bound scenario).

Assumptions for each scenario are set out in the table below.

Table 5: Assumptions made in the scenario

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	5.5%	7.5%	2.3%
Demand Growth	Minimum demand forecast (POE50)	Minimum demand forecast (POE50)	Minimum demand forecast (POE50)
Capital cost	100%	125%	75%
Operating expenditure	100%	125%	75%
VCR	AER Latest VCR (escalated) 100%	AER Latest VCR (escalated) 70%	AER Latest VCR (escalated) 130%
Scenario weighting	50%	25%	25%

Since the central scenario represents the most likely scenario to occur, it has been weighted it at 50 per cent. The other two scenarios reflect extreme combinations of assumptions designed to stress test the results. Accordingly, these scenarios are weighted at 25 percent each.

As stated in Table 5, the latest minimum demand forecast (POE50) has been used in all 3 scenarios for the calculation of expected unserved energy.

Parameters used in this commercial evaluation:

Table 6: Parameters used in the commercial evaluation

Parameter	Parameter Description	Value used for this evaluation
Discount year	Year that dollar values are discounted to	2021/22
Base year	The year that dollar value outputs are expressed in real terms	2021/22 dollars
Period of analysis	Number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	25 years

The capex figures in this OER do not include any real cost escalation.

4.2. Commercial evaluation results

The commercial evaluation has been undertaken only for the technically feasible options where the detailed costs are available; that is, only Option B and D have been analysed been against the Base Case.

The commercial evaluation of the technically feasible options is set out in Table 7. Details appear in Appendix A.

Table 7 - Commercial evaluation (PV, $ million)

Option	Capital Cost PV	OPEX Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option B	8.4	2.0	-2.4	-7.1	5.8	-1.5	2
Option D	7.3	1.8	-1.3	-5.8	6.7	-0.4	1

4.3. Preferred option

Both Options B and D provides similar benefits by reducing the EUE associated with radialisation of the network. However, the capital expenditure of Option D is higher than Option B by approx. $1m which yields relatively higher net benefits for Option D compared to Option B (Refer Table 7).

Amongst the two options considered in the commercial evaluation, both options B and D have resulted in negative NPV for the Central and Low scenarios whilst both options resulted in positive NPV only for the High scenario. Overall, Option D yields a higher NPV compared to Option D yet both are negative. Despite the negative weighted NPV, as the identified need is to meet the Compliance requirement of System Standards and secure network operation, an option with a negative weighted NPV is acceptable. Hence, Option D is preferred.

Further, although both of these options require the extension of existing switchyard bench, Option D would require less bench extension compared to Option B.

Based on the above factors, Option D has been selected as the preferred option.

The following investments will be undertaken in Option D:

- Install two (2) 11 MVAr/66 kV reactors at Deniliquin 132/66 kV substation.

The high level scope of the preferred option (Option D) is as below:

- extend the bench by 616 sq. meters.
- extend the fence by 54 linear meters.
- extend the cable trench approximately 34 meters (two right angle bends included).
- extend the 66 kV busbar with rigid bus approximately 25 meters to the south. 2 x 3 phase bus supports will be required;
- install 2 x circuit breaker bays, each comprising: 1 x disconnector, 1 x dead tank circuit breaker, 1 x 3 phase gantry support, 2 x single phase low bus supports.
- install a foundation and bund, and pipework to the oil dump tank and two (2) 11 MVAr 66 kV reactors

Capital and Operating Expenditure

The preferred option identified in this document requires capital expenditure of $8.5 million. For the NPV analysis an annual operating expenditure of 2 per cent of the capital cost has been identified for this option.

The base case requires no additional capital or operating expenditure to current requirements.

Regulatory Investment Test

As the estimated cost of the preferred option for this Need is above the Regulatory Investment Test (RIT-T) threshold of $7 million and given there are non-network options to be assessed, a RIT-T will be required.

5. Optimal Timing

The test for optimal timing of the preferred option has been undertaken. The approach taken is to identify the optimal commissioning year for the preferred option where net benefits (including avoided costs and safety disproportionality tests) of the preferred option exceeds the annualised costs of the option. The commencement year is determined based on the required project disbursement to the meet the commissioning year based on the OFS.

As the non-compliance of voltage requirement and the NSCAS gap in Coleambally area have been already identified, this need has to be addressed immediately. Hence the optimal timing of the Need is defined such that the project will be commenced immediately after the initial issue of this document is approved.

The results of optimal timing analysis is:

- Optimal commissioning year: 2024/25
- Commissioning year annual benefit: $611k
- Annualised cost: $515k

Based on the optimal timing, the project is expected to commence in the 2018-2023 period and a substantial proportion of the capital expenditure is expected to occur in 2023-2028 Regulatory Period.

6. Recommendation

Given there may be non-network options that will be required to be assessed, the final preferred option will be determined through the RIT-T process based on detailed network analysis, market modelling, technical and economic feasibility. However, based on the option evaluations in this report, it is recommended the preferred network option is:

Option D – Install two 11 MVAr 66 kV reactors at Deniliquin 132/66 kV substation.

The RIT-T for this project is underway. The Project Specification Consultation Report (PSCR) has been completed. The outcome of the RIT-T will confirm the final preferred option amongst all network and non-network options being considered.

It is expected that an expenditure up to $100k is required to complete ONLY the RIT-T for this Need. At the completion of the RIT-T, a final recommendation will be made to determine whether the project proceeds with the same option scope (Option D) or a different option will be selected as the final preferred option.

The remainder of the budget for the development to proceed from DG1 to DG2 will be allocated based on the outcome of the RIT-T and the selection of the final preferred option.[13]

[13] Total expenditure required to proceed from DG1 to DG2 is $800k. The remainder of the budget for the project development is $800-$100k = $700k.

Appendix A – Option Summaries

Table 8: Option B Summary

Project Description	Maintain voltage in South western Subsystem		
Option Description	**Option B – Install two 10 MVAr 132 kV reactors at Deniliquin**		
Project Summary			
Option Rank	1	Investment Assessment Period	25
Asset Life	45	NPV Year	2022
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	-2.4	Annualised CAPEX ($m)	0.6
NPV @ Lower Bound Scenario (PV, $m)	-7.1	Network Safety Risk Reduction ($m)	N/A
NPV @ Higher Bound Scenario (PV, $m)	5.8	ALARP	N/A
NPV Weighted (PV, $m)	-1.5	Optimal Timing	2024/25
Cost			
Direct Capex ($m)	8.8	Network and Corporate Overheads ($m)	0.9
Total Capex ($m)	9.7	Cost Capex (PV,$m)	8.4
Terminal Value ($m)	5.2	Terminal Value (PV,$m)	1.4

Table 9: Option D Summary

Project Description	Maintain voltage in South western Subsystem		
Option Description	**Option D – Install two 11 MVAr 66 kV reactors at Deniliquin**		
Project Summary			
Option Rank	1	Investment Assessment Period	25
Asset Life	45	NPV Year	2022
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	-1.3	Annualised CAPEX ($m)	0.5
NPV @ Lower Bound Scenario (PV, $m)	-5.8	Network Safety Risk Reduction ($m)	N/A
NPV @ Higher Bound Scenario (PV, $m)	6.7	ALARP	N/A
NPV Weighted (PV, $m)	-0.4	Optimal Timing	2024/25
Cost			
Direct Capex ($m)	7.7	Network and Corporate Overheads ($m)	0.8
Total Capex ($m)	8.5	Cost Capex (PV,$m)	7.3
Terminal Value ($m)	4.5	Terminal Value (PV,$m)	1.3