BCR Bells Creek Central – Establish 132/11kV Zone Substation

Justification Memo

19 November 2024

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1 SUMMARY

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☒ Reliability ☐ CECV ☐ Safety ☐ Environment ☒ Financial
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The Sunshine Coast area continues to see strong population growth and economic development. Major developments are currently progressing near Caloundra in the southern parts of Sunshine Coast. There is a large master-planned community (Aura) currently being developed in the areas of Bells Creek, that when completed is forecast to add at least 47MVA load to the network. The Aura development is a mix of residential, commercial and industrial areas. It includes shopping and dining precinct, community centres, schools, and transport centre in addition to the residential housing developments. Furthermore, the Sunshine Coast Industrial Park (SCIP) located in Bells Creek North is forecast to have an additional 15MVA of load to be added to the network. These developments are situated in the Caloundra 132/11kV Zone Substation supply area, it is forecast that they will add 62MVA to the ultimate electrical demand to the substation.

Caloundra 132/11kV Zone Substation (SSCLD) provides electricity supply to over 22,600 predominantly domestic customers in the Aroona, Bells Creek, Caloundra, Currimundi, Little Mountain, Meridan Plains, Pelican Waters and Shelly Beach. It is supplied by part of a 132kV ring network from Mooloolaba 132/11kV Zone Substation (SSMLB), that is in turn supplied from Palmwoods Bulk Supply Substation (SSH9).

In our cost benefit analysis, we modelled the need for a new substation at Bells Creek Central being required by 2032.. Left unaddressed there will be an ongoing high level customer impact and business impact risks associated with not being able to supply new customers in the Aura and SCIP developments in a timely manner, as well as legislated requirements risk due to non-compliance to the Energex Distribution Authority requirements. These risks will continue to increase as more customers move into the area.

As will be discussed further in this memo, the AER has a different interpretation of the Safety Net security standard limits. Even under the AER's interpretation, SSCLD will breach the Safety Net compliance obligation around 2035. Even accounting for this, our CBA shows that the establishment of Bells Creek Central zone substation in 2027 maximises value for our customers over the alternative options.</td></tr>
<tr><td>Summary of preferred option</td><td>The preferred option is that Energex establish Bells Creek Central 132/11kV Zone Substation (SSBCR) with 1 x 60MVA 132/11kV transformer, 2 x 132kV busses and 2 x 11kV busses, establish double circuit 132kV feeder with a mix of 8kms of overhead and 2.1kms of underground construction, reconfigure the 11kV network, replace 6.4km of OHEW with OPGW, establish 3.3km of ADSS and 6.2km of underground optical fibre, and upgrade 132kV feeder protection at Mooloolaba (SSMLB) and Caloundra (SSCLD) zone substations.</td></tr>
<tr><td>Expenditure</td><td><table><tr><th>Year</th><th>Previous period</th><th>2025-26</th><th>2026-27</th><th>2027-28</th><th>2028-29</th><th>2029-30</th><th>2025-30</th></tr><tr><td>$m, direct 2022-23</td><td>$18.951m</td><td>$39.456m</td><td>$23.461m</td><td>$0.257m</td><td>$0m</td><td>$0m</td><td>$63.174m</td></tr></table></td></tr>
<tr><td>Benefits</td><td>After completion of the recommended works, the resulting level of risk on the impacts to customer, business and legislated requirements are down to As Low As Reasonably Practicable (ALARP). Furthermore, this memo outlines the financial benefits and positive cost benefit analysis outcome demonstrating that maximises the value for our customers.</td></tr>
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Consumer engagement	On 9th November 2020 Energex published the Non-Network Options Report (NNOR) prepared in accordance with the requirements of clause 5.17.4(e) of the NER providing details on the identified need in the Caloundra area including both technical and economic information about possible solutions. This report sought information from interested parties regarding alternative potential credible options or variants to the potential credible option (network Option 1) presented by Energex. In response to the NNOR, Energex received three submissions and identified one credible option. A Draft Project Assessment Report (DPAR) was published on 16 August 2021, in accordance with the requirements of clause 5.17.4(i) of the NER, explaining Energex's preferred solution (Option 1) to address the identified need. The DPAR sought information from interested parties about possible alternate solutions to address the need for investment and the consultation was open for a minimum of six weeks. No submissions were received in response to the DPAR. Due to the proposed preferred option being more that the $12 million cost threshold a Final Project Assessment Report (FPAR) was published on 22nd October 2021 in accordance with the requirements of clause 5.17.4(o) of the NER. The period (within 30 days) during which Registered Participants and Interested Parties may, by notice to the AER, dispute conclusions made by Energex in the FPAR (on the grounds of RIT-D application or assessment errors) expired on 21st November 2021. Hence, the RIT-D process for the project has concluded. The Final Project Assessment Report from the RIT-D process can be accessed via the link below: • Caloundra Final Project Assessment Report

2 BACKGROUND

The Sunshine Coast area continues to see strong population growth and economic development. Major developments are currently progressing near Caloundra in the southern parts of Sunshine Coast. There is a large master-planned community (Aura) currently being developed in the areas of Bells Creek, that when completed is forecast to add at least 47MVA load to the network. The Aura development is a mix of residential, commercial and industrial areas. It includes shopping and dining precinct, community centres, schools, and transport centre in addition to the residential housing developments. Furthermore, the Sunshine Coast Industrial Park (SCIP) located in Bells Creek North is forecast to have an additional 15MVA of load to be added to the network. These developments are situated in the Caloundra 132/11kV Zone Substation supply area, it is forecast that they will add 62MVA to the ultimate electrical demand to the substation.

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In our cost benefit analysis, we modelled the need for a new substation at Bells Creek Central being required by 2032. Left unaddressed there will be an ongoing high level customer impact and business impact risks associated with not being able to supply new customers in the Aura and SCIP developments in a timely manner, as well as legislated requirements risk due to non-compliance to the Energex Distribution Authority requirements. These risks will continue to increase as more customers move into the area.

3 IDENTIFIED NEED AND COST BENEFIT ANALYSIS

The Project Approval Report (PAR) that we have included with our Revised Regulatory Proposal outlines two identified needs for this project – Distribution Feeder limitations and Substation capacity limitations.

- **Distribution feeder limitations –** As outlined in the PAR, distribution feeders CLD18A, CLD6A and CLD24A are all forecast to exceed their target maximum utilisation in summer 2026/27. This load is the result of our obligation to connect new residential customers to our network, which is outlined in Section 66 of the National Electricity Law. The volume of customers connecting is significant, which is driving this load growth.
- **Substation capacity –** SSCLD will also see a network limitation under Energex's interpretation of the Safety Net. Our cost benefit modelling incorporated the need for a substation due to a Safety Net breach in 2032. This was included in our cost benefit analysis as a cost in 2032.

In this way, the primary driver for the project is not a Safety Net limitation, but rather a regulatory obligation to continue to connect customers to our network as more houses are built in the Caloundra area. The Safety Net was only a secondary driver that was factored into the cost benefit analysis in analysing alternative options to resolve the identified needs.

3.1 AER Feedback on Safety Net thresholds

In its Draft Decision, the AER outlined that they had a differing interpretation of the Safety Net. We have discussed this in our RRP document, however, have included Table 1 below outlining the differences between the interpretation.

Table 1 – Interpretation of Urban Customer Safety Net Obligations

Range of load unsupplied	Energex interpretation of restoration time	AER interpretation of restoration time
Greater than 40MVA	No time specified	30 minutes to reduce the load unsupplied to 40MVA or lower
40MVA to greater than 12MVA	30 minutes to reduce the load unsupplied to 12MVA or lower.	3 hours to reduce the load unsupplied to 12MVA or lower
12MVA to greater than 4MVA	3 hours to reduce the load unsupplied to 4MVA or lower	8 hours to reduce the load unsupplied to 4MVA or lower
Less than or equal to 4 MVA	8 hours to have supply to all load restored	No time requirement to restore supply – can be without supply for more than 8 hours.

Under this interpretation, the AER did not accept our need to establish SSBCR, mistakenly including this substation as part of our Safety Net driven expenditure. As we outlined earlier, the primary identified need is our obligation to connect customers and the resultant distribution network limitations that stem from this. A subsequent limitation was a Safety Net breach at SSCLD.

3.2 Counterfactual and Cost Benefit Analysis

In our original presentation of our CBA, we utilised a lowest cost NPV analysis to demonstrate that the establishment of SSBCR was the most cost-effective solution to meet our dual regulatory obligations of continuing to connect customers without overloading our network, as well as meet the Safety Net obligations for SSCLD when this threshold was exceeded. While we did this in good faith, this appears to have caused confusion with the AER. As a result, we have framed our CBA to demonstrate the benefits of our approach over what would be the alternative 'business as usual', 'do nothing materially different' or 'do minimal' approach.

Defining the counterfactual

Under this approach, we have defined our counterfactual as continuing to construct new feeders from SSCLD to the Aura development as our feeders become overloaded. This is consistent with how we have developed this network over time, with 3 feeders currently built from SSCLD to Aura to supply the load, with a fourth feeder approved for establishment by 2025. The expenditure pattern of the counterfactual, consistent with Option 2 in our PAR, is:

- Stage 1 – establishing 2 x 11kV feeders (approximately 10km each) in new conduits from SSCLD and reconfiguration of the 11kV network to supply the growing load at Aura in 2027.

- Stage 2 – establishing 2 x 11kV feeders (approximately 10km each), in conduits installed in Stage 1, from SSCLD and reconfiguration of the 11kV network to supply the growing load at Aura in 2030.
- Stage 3 – establishing SSBCR with an indoor 132kV GIS (for 2 x 132kV feeders, 2 x transformers and 1 x bus section CB), 1 x 60MVA 132/11kV transformer, 2 x 11kV switchboards, 132kV DCCT mixed overhead and underground feeder, 4 x 11kV feeders and reconfiguration of the SSCLD 11kV network in 2032 under our Safety Net obligations
- Stage 4 – establishing 2nd 60MVA 132/11kV transformer at SSBCR in 2037 under our Safety Net obligations.

These costs, and the associated operational expenditure associated with establishing new feeders have been factored into our cost benefit analysis as the counterfactual. That is, where an intervention or proposed project removes or defers these benefits, this will be represented as a financial benefit. Table 2 shows the expenditure that forms the counterfactual case.

Table 2 – Expenditure for the Counterfactual

Expenditure Type	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capex	19.79	0.00	0.00	10.38	0.00	109.75	0.00	0.00	0.00	0.00	5.00
Opex	0.02	0.02	0.02	0.03	0.03	0.16	0.16	0.16	0.16	0.16	0.17

As Table 2 shows, the Capex comes in four distinct years, which lines up with Stage 1 to Stage 4 outlined earlier, while the Opex lines up with our estimated Opex requirements for each stage. For simplicity, we have only included expenditure up until 2037 even though our CBA model includes expenditure for 20 years. It should be noted that in line with our internal business practises, costs above are Total costs and include a portion of capitalised overheads in the approval amount. We have maintained this approach to costs so that these costs reconcile with the original NPV that we provided to the AER as part of the RP.

Options analysis

Our attached PAR includes 6 options (1 is now the counterfactual, so 5 extra options in total) to resolve the identified need. To simplify the analysis in this memo, we have only included a CBA on the preferred option from that analysis to demonstrate that this is CBA positive. It should be noted that the approach we have taken will be consistent among each option and that Option 1 will still be the preferred option were we to undertake this analysis for all 5 alternatives to the counterfactual.

Our Option 1 is the establishment of a new single transformer substation at Bells Creek Central in 2027, with an additional transformer proposed in 2030. Table 3 shows the expenditure associated with Option 1.

Table 3 – Expenditure for Option 1

Expenditure Type	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capex	109.75	0.00	0.00	5.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Expenditure Type	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Opex	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13

As Table 3 outlines, the Capex comes in two distinct years, which lines up with the initial establishment of the substation and then the additional transformer. The Opex lines up with our estimated Opex requirements for each stage. For simplicity, we have only included expenditure up until 2037 even though our CBA model includes expenditure for 20 years.

Net Present Value Assessment

We have utilised an incremental cost method to assess the NPV of Option 1, to determine whether Option 1 increases value for our customers over the counterfactual alternative of business-as-usual feeder construction from SSCLD until we reach a Safety Net compliance issue. Table 4 shows the incremental expenditure that results from the implementation of Option 1, as compared to the counterfactual.

Table 4 – CBA for Option 1

Expenditure Type	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capex	-89.97	0	0	5.38	0	109.75	0	0	0	0	5.00
Opex	-0.11	-0.11	-0.11	-0.99	0.32	0.32	0.32	0.32	0.32	0.32	0.34

As Table 4 outlines, there are significant benefits and costs associated with implementing Option 1. For instance, there is a negative $89.97m cashflow based on investing in developing the substation in 2027, while there is a $109.75m benefit in 2032 because we have already invested in the substation.

Utilising a 3.5% WACC and a 20-year assessment period, the NPV is $9.25m positive, demonstrating that Option 1 is more beneficial for customers than continuing with the counterfactual option. More information can be found in the NPV Model attached with this business case.

3.3 AER's Interpretation of Safety Net Limits for Caloundra Zone Substation

As discussed earlier, the AER did not accept the expenditure associated with this business case because they had mistakenly assumed it was driven by the Safety Net. The AER have also expressed concern about our interpretation of the Safety Net and have not accepted some other investments because of their alternative interpretation. While we disagree with their interpretation, and have outlined this in our RRP, to avoid doubt we have undertaken an analysis based on their interpretation and how it impacts on the timing of the Safety Net limitation at SSCLD.

Under the AER's interpretation, SSCLD will be forecast to breach the Safety Net requirements in 2035. This is based on the forecast presented in the PAR and the assessment of the remaining unsupplied load requirements inherent in the AER's interpretation. Under this interpretation, the counterfactual case changes, with an extra stage for a new feeder as listed below:

- Stage 1 – establishing 2 x 11kV feeders (approximately 10km each) in new conduits from SSCLD and reconfiguration of the 11kV network to supply the growing load at Aura in 2027.
- Stage 2 – establishing 2 x 11kV feeders (approximately 10km each), in conduits installed in Stage 1, from SSCLD and reconfiguration of the 11kV network to supply the growing load at Aura in 2030.
- Stage 3 – establishing 1 x 11kV feeder (approximately 10km), in conduits installed on Stage 1, from SSCLD ad reconfiguration of the 11kV network to supply the growing load at Aura in 2033
- Stage 4 – establishing SSBCR with an indoor 132kV GIS (for 2 x 132kV feeders, 2 x transformers and 1 x bus section CB), 1 x 60MVA 132/11kV transformer, 2 x 11kV switchboards, 132kV DCCT mixed overhead and underground feeder, 4 x 11kV feeders and reconfiguration of the SSCLD 11kV network in 2035 under our Safety Net obligations
- Stage 5 – establishing 2nd 60MVA 132/11kV transformer at SSBCR in 2037 under our Safety Net obligations.

We have applied the same methodology to determine the NPV under the AER's alternative interpretation of the Safety Net obligation, determining a positive NPV of $4.8m, again demonstrating that even under the AER's interpretation, establishing Bells Creek Central provides value for customers above simply continuing to construct long feeders from SSCLD.

4 CONCLUSION

The AER should have allowed the expenditure associated with Bells Creek Central in their Draft Decision. They incorrectly identified Bells Creek Central as a Safety Net driven project and should have assessed it's identified need as a regulatory obligation to connect customers which resulted in distribution feeder limitations because of the significant increase in load.

In our RP because this was a compliance obligation, we undertook a lowest-cost NPV analysis. However, to avoid further confusion we have defined the counterfactual as the business-as-usual process of continuing to build 11kV feeders from SSCLD. Having done this, we have undertaken a CBA based on financial savings from establishing a new substation, demonstrating that this project has a positive CBA and maximises the value to our customers. As such, we submit that the cost of Bells Creek Central zone substation as included in the capex model be included in the AER's Final Decision.