



# Endorsements

Version	Date	Comments
0	August 2020	Initial issue
1	March 2022	Addendum added to detail the additional scope for preferred option. Sections updated: Executive summary and Recommendation.

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## 1. Executive summary

This Case for Investment recommends purchasing network support payments from an externally owned and operated grid connected battery.

Penrith Zone Substation supply area has a firm capacity of 52MVA. It provides supply to a mix of commercial and residential load. The South Penrith area is expected to grow with multiple new residential and commercial developments will lead to load at risk commencing in Summer 2022/23 if no proactive intervention is taken.

To address the load at risk, the following options were examined:

- Option 1 – Establishment of a new 33/11kV zone substation;
- Option 2 – Purchase network support from grid connected battery;
- Option 3 – Build a grid connected battery; and
- Option 4 – Traditional Demand Management agreements.

This CFI utilised the Houston Kemp model to carry out a cost benefit analysis to compare all four options. Option 2 is the preferred option despite not having the highest NPV due to a number of non-quantified benefits that this option offers including an opportunity for Endeavour Energy to gain understanding on how to establish and manage network support, both technically and commercially, via an externally owned and operated battery or other energy source.

This Revision 1 of the CFI now includes an Addendum to describe additional scope and costs required to implement the preferred option that was not originally foreseen when Revision 0 of the CFI was presented. The estimate for these additional works is \$1.38m and while these costs were not included in the original CFI, the outcome of the original NPV would not have been materially impacted had these works been included at the time.

It is recommended that:

- The project proceeds with Option 2 (purchase network support from an externally owned grid connected battery);
- Project/s be raised for the necessary enabling works detailed in the Addendum for completion in FY 22 and FY 23 as required before the energisation of the grid connected battery (prior to end of calendar year 2022);
- Continue engagement with Procurement with respect to negotiation of network support agreement with Firm Power.

## 2. Purpose

The purpose of this document is to present the case for investment to purchase network support from a grid connected battery owned and operated by a third party provider in the medium term in order to address the network limitation in the Penrith area.

## 3. Need/opportunity to be addressed

Penrith Zone Substation is a 132/11kV substation with a firm capacity of 52MVA. It provides supply to a mix of mainly commercial and some residential load. The zone substation has two of 52MVA transformers which cannot operate in parallel due to fault level constraints. Multiple new residential and commercial developments in the South Penrith area will further increase the load on the Penrith ZS.

The current demand forecast shown in Table 1 below indicates load at risk commencing in Summer 2022/23. The investment is required to address the risk of involuntary load shedding arising from increasing demand in the South Penrith area.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Firm capacity (MVA)	52	52	52	52	52	52	52	52	52	52
Demand forecast 50% POE (MVA)	45.0	50.6	56.2	58.6	59.5	60.1	60.4	60.3	60.3	60.3
Load at Risk (MVA)	-	-	4.2	6.6	7.5	8.1	8.4	8.3	8.3	8.3

**Table 1 – Demand forecast**

Short term deferral of the new zone substation will be achieved through completion of a project underway to install feeder automation / load transfer scheme. Land has been recently acquired to enable the establishment of the new zone substation.

## 4. Consequence of ‘no proactive intervention’

The “Do Nothing” approach will result in significant expected unserved energy in the supply area from 2023 onwards as well as increased STPIS penalties. It also carries with it significant reputational risks of negative media coverage and NSW Government dissatisfaction if Endeavour Energy is unable to meet supply requirements for this area.

In terms of Risk Cost assessment, the “Do Nothing” option provides a base case where the risks are valued by applying a Value of Customer Reliability (VCR) to the forecast expected unserved energy. The VCR values used by Endeavour Energy in its modelling are the same as those published by AER. This approach was endorsed by the AER during the determination process. Table 2 shows the annualised risk cost of no proactive intervention.

	2023	2024	2025	2026	2027
Risk cost (\$)	573,242	2,298,377	3,464,620	4,274,008	4,785,426

**Table 2 – Risk cost of 'no proactive intervention'**

## 5. Description of proposed method to address need or opportunity and options considered

### Option 1 – Establishment of a new 33/11kV zone substation

This option is to establish a new zone substation with two 35MVA transformers and 2 x 33kV underground feeders. The estimated cost for a new zone substation build is around \$25M. Based on current demand forecast, works related to planning, RIT-D, sub transmission route and others will need to commence in 2022 for commissioning in FY28. This option will meet the long term network capacity needs and in the South Penrith area with some level of load at risk in the short term.

### Option 2 – Purchase network support from grid connected battery

This option is to purchase network support from a grid connected battery to be owned and operated by an external company (Firm Power). Annual network support payments will commence in 2026 all the way to 2030 in order to address the load at risk in the area in the medium term. Based on current demand forecasts, the grid battery will not replace the eventual need for the substation. However, it will allow the deferral of building the new substation by three years based on financial modelling.

The proposed battery will be a 30MWh/20MVA unit and will be able to provide 7.5 MVA of network support for a 4-hour duration during days of peak demand.

Firm Power made an application to connect a battery to the 11kV busbar at Penrith Zone Substation and negotiated to lease under-utilised land within the substation. The grid battery will allow Firm Power to access revenue stack from participation in the wholesale market through energy arbitrage (charging the battery off peak and selling at peak) as well as providing frequency support to AEMO through the FCAS market. This represents around 80% of their revenue.

The cost to build the new zone substation (Option 1) is publicly available via the Distribution Annual Planning Report (DAPR). Information from the DAPR allowed Firm Power to make an offer to Endeavour Energy to provide network support that is lower than the deferral value of Option 1.

Firm Power has applied for an ARENA grant on the basis of assisting establish a new market for distribution system support as this will be the first independently owned grid connected battery providing network support in Australia. The grant is sought to partially fund the project estimated to be worth \$25M. Endeavour Energy has been providing information to assist Firm Power in their bid to secure ARENA funding including DCEO letter to Firm Power in May 2020 indicating in-principle support for the proposal as well as development of a Support Agreement Principles document.

### Option 3 – Build a grid connected battery

This option is for Endeavour Energy to fully own, build and operate a grid connected battery with the exact same capacity as Option 2. The grid battery will be commissioned in 2025 to address the load at risk in the medium term. Based on the current demand forecast, a 30MWh/20MVA battery will provide a three year deferral of the zone substation build. The estimated cost for this option is around \$25M.

Whilst the battery will be able provide network support to mitigate load at risk, existing regulations and ring-fencing guidelines prevents Endeavour Energy to access the same revenue stack as external unregulated businesses.

### Option 4 – Traditional Demand Management agreements

This option follows the process of seeking expressions of interest from the non-network solutions market for alternatives to address the network constraint at a lower cost than the traditional zone substation build.

Based on the response gathered from the South Erskine Park Zone Substation RIT-D as well as other market obtainable rates, the approximate cost to establish load shifting/curtailment and energy efficiency contracts would be in the order of \$1M (opex) per year for atleast three to five years.

Option	Description	Solution Type	Proposed Investment Cost (real FY21) \$M	PV Benefits (quantified risk reduction) \$M	NPV \$M	Rank	Evaluation and comment
1	New Zone Substation build	Traditional network solution	25 (capex)	68	51	3	<b>Non-preferred option</b> Low NPV. This option would be excluded based on application of RIT-D as it is not with the highest NPV.
2	Grid battery support payments and deferred zone substation build	Non-network solution	3.7 (opex) 25 (capex)	76.3	60.7	1	<b>Preferred option</b> Similar NPV to Option 4 but offers a number of non-quantified benefits. Refer to below. This option would qualify for DMIS.
3	Grid battery build (EE owned) and deferred zone substation build	Network Solution	51 (capex)	75	41	4	<b>Non-preferred option</b> Low NPV driven by regulatory restrictions to access full stack of market benefits. This option would be excluded based on application of RIT-D as it is not with the highest NPV.
4	Traditional demand management agreements and deferred zone substation build	Traditional Non-network solution	3.7 (opex) 25 (capex)	73.5	58	2	<b>Non-preferred option</b> Similar NPV as Option 2, but does not offer the same non-quantified benefits. Refer to below. This option would qualify for DMIS.

**Table 3 – Option summary table**

Table 3 shows that the preferred option is Option 2. The ranking of the preferred option is based on the highest NPV. Costs and benefits values are calculated in accordance with the AER investment test rules and guidelines. Additionally, while Option 2 has as similar NPV to option 4 (traditional DM), there are a number of other non-quantified benefits arising from this option including:

- Tangible demonstration that the organisation is responding to Regulator and customer criticism provided during the revenue reset process.
- Opportunity to gain an understanding of how, both technically and commercially, to establish and manage network support via an externally owned battery or other energy source.

## 6. Detailed costs and benefits analysis

The Houston Kemp model (HK model) was utilised in the economic evaluation of the viable options and Endeavour Energy's Unserved Energy Template was used to calculate the expected unserved energy.

The assumptions used in the HK model are:

- A study period of 30 years;
- The commercial discount rate was set to 6.44% based on the pre-tax real WACC for the 2019-24 determination period plus an additional 2%;
- A VCR of \$39,918 based on 37% residential, 41% commercial, 21% industrial load and 2% CPI;
- A maintenance cost estimate based on 1% of the project cost; and
- The benefits of options are based on the avoided unserved energy.

Capital cost				[Do not insert or delete rows from this table]			
Number	Option name	Capex component	Amount	Start year	End year	Commission year	Asset life
1	New ZS build	Build a new 33/11kV ZS	3,000,000	2025	2025	2028	45
1	New ZS build	Build a new 33/11kV ZS	12,000,000	2026	2026	2028	45
1	New ZS build	Build a new 33/11kV ZS	10,100,000	2027	2027	2028	45
2	Grid connected battery by third party	11kV feeder works for battery conn	300,000	2022	2022	2022	45
2	Grid connected battery by third party	New ZS build deferred by 3 yrs	3,000,000	2028	2028	2031	45
2	Grid connected battery by third party	New ZS build deferred by 3 yrs	12,000,000	2029	2029	2031	45
2	Grid connected battery by third party	New ZS build deferred by 3 yrs	10,100,000	2030	2030	2031	45
3	Build grid connected battery	EE built and owned BESS	25,000,000	2024	2024	2025	10
3	Build grid connected battery	EE built and owned BESS	300,000	2022	2022	2022	10
3	Build grid connected battery	New ZS build deferred by 3 yrs	3,000,000	2028	2028	2031	45
3	Build grid connected battery	New ZS build deferred by 3 yrs	12,000,000	2029	2029	2031	45
3	Build grid connected battery	New ZS build deferred by 3 yrs	10,100,000	2030	2030	2031	45
4	NNO - defer ZS build for 3 years	Defer ZS build by traditional DM	3,000,000	2028	2028	2031	45
4	NNO - defer ZS build for 3 years	Defer ZS build by traditional DM	12,000,000	2029	2029	2031	45
4	NNO - defer ZS build for 3 years	Defer ZS build by traditional DM	10,100,000	2030	2030	2031	45

Figure 1 – Capital cost input into Houston Kemp model

Net present value for each option							
Number	Option name	Unit	PV 'market benefits'	PV avoided 'risk cost' benefits	PV Costs	NPV	Rank
1	New ZS build	\$	68.0 M		-16.8 M	51.3 M	3
2	Grid connected battery by third part	\$	76.7 M		-16.0 M	60.7 M	1
3	Build grid connected battery	\$	74.9 M		-33.8 M	41.1 M	4
4	NNO - defer ZS build for 3 years	\$	73.5 M		-15.4 M	58.1 M	2

Figure 2 – Houston Kemp NPV model output

It is noted that the preferred option (Option 2) is similar in NPV to that of option 4. However, there are a number of non-quantified benefits that Option 2 offers including a tangible demonstration that Endeavour Energy supports non-network alternatives beyond the traditional demand management schemes. In previous discussions with the AER, they have indicated support for the proposed approach including not requiring the RIT-D process to be completed until the zone substation is required. In this case, the zone substation will still have to be built when the grid battery can no longer meet the requirements of the growing demand in the area. The AER have reached this view acknowledging that the current RIT-D process, coupled with the just in time principle, does not allow sufficient time for a grid battery type solution to respond to emerging demand driven needs.

The preferred option also provides an opportunity for Endeavour Energy to gain understanding on how to establish and manage network support, both technically and commercially, via an externally owned and operated battery or other energy source.

## 7. Listing of benefits, risks and residual risks considered

The NER states that quantifiable economic market benefits (needs) include changes in involuntary load shedding. The costs and benefits analysis described in the previous section included this benefit in determining the preferred option. Endeavour Energy's Unserved Energy Template was used to estimate the involuntary load shedding that can be prevented as a result of proactive action. The involuntary load shedding was utilised by the HK model along with a Value of Customer Reliability to calculate a market benefit.

There were no other identified risks that were included in the costs and benefits analysis.

### 7.1 Safety Considerations

The constraints analysed in the South Penrith area capacity related and there are no known safety issues with the existing network assets. In analysing expected unserved energy for the constraint we have considered the impact of potential widespread outages. The proposed investment solutions will be designed to current network standards to ensure safe operation of the network for our staff and general public. The proposed solution reduces the expected unserved energy and is considered SFAIRP.

## 8. Scenario Analysis

Scenario analysis has been carried out by the model. The parameters of the scenario analysis are presented below.

Scenarios		Scenario weighting						
Scenario selection		Scenario 1	Scenario 2	Scenario 3				
Scenario	Scenario 1	0.50	0.25	0.25				
<b>General inputs</b>								
<b>General</b>								
Commercial discount rate	Unit	Value	Selection	Scenario 1	Scenario 2	Scenario 3	User defined	
	Percent	6.44%	Central	Central	High	Low	Central	
<b>Cost inputs</b>								
<b>Cost</b>								
Capital cost	Unit	Value	Selection	Scenario 1	Scenario 2	Scenario 3	User defined	
Planned routine maintenance and refurbishment	Percent	100%	Central	Central	High	Low	Central	
Unplanned corrective maintenance	Percent	100%	Central	Central	Low	High	Central	
Decommissioning costs	Percent	100%	Central	Central	Low	High	Central	
Non-network option provider costs	Percent	100%	Central	Central	High	Low	Central	
Cost X	Percent	100%	Central	Central	Central	Central	Central	
Cost Y	Percent	100%	Central	Central	Central	Central	Central	
Cost Z	Percent	100%	Central	Central	Central	Central	Central	
<b>Benefit inputs</b>								
<b>Avoided 'risk cost' benefits</b>								
Reliability and security risk costs	Unit	Value	Selection	Scenario 1	Scenario 2	Scenario 3	User defined	
Safety and health risk costs	Scenario	NA	Central	Central	Low	High	Central	
Environmental risk costs	Scenario	NA	Central	Central	Low	High	Central	
Legal/regulatory compliance risk costs	Scenario	NA	Central	Central	Low	High	Central	
Financial risk costs	Scenario	NA	Central	Central	Low	High	Central	
<b>Market benefits</b>								
Involuntary load shedding - VCR	Unit	Value	Selection	Scenario 1	Scenario 2	Scenario 3	User defined	
Involuntary load shedding - MWh	Scenario	\$39,918	Central	Central	Low	High	Central	
Difference in timing of unrelated expenditure	Scenario	NA	Central	Central	Low	High	Central	
Difference in timing of unrelated expenditure	Percent	100%	Central	Central	Low	High	Central	
Voluntary load curtailment - VCR	Scenario	\$39,918	Central	Central	Low	High	Central	
Voluntary load curtailment - MWh	Scenario	NA	Central	Central	Low	High	Central	
Costs for non RIT-D proponent parties	Percent	100%	Central	Central	Central	Central	Central	
Electricity energy losses	Percent	100%	Central	Central	Central	Central	Central	
Change in load transfer capacity and the capacity for embedded generators to take	Percent	100%	Central	Central	Central	Central	Central	
Other classes of market benefits	Percent	100%	Central	Central	Central	Central	Central	

Figure 3 – Houston Kemp model scenario parameters

Variable	Scenario 1 - baseline	Scenario 2 – low benefits	Scenario 3 – high benefits
Capital cost	Estimated network capital costs	25% increase in the estimated network capital costs	25% decrease in the estimated network capital costs
Value of customer reliability (VCR)	\$39.92/kWh (from AER VCR report)	\$27.94/kWh 30% lower than baseline	\$51.89/kWh 30% higher than baseline
Discount rate	6.44% (WACC)	4.44% (WACC - 2%)	8.44% (WACC + 2%)
Maintenance costs	Estimated network maintenance costs	25% decrease in the estimated network maintenance costs	25% increase in the estimated network maintenance costs
Scenario weighting	50%	25%	25%

Table 4 – Summary of scenarios investigated

The scenarios have been weighted as 50% for Scenario 1 being the most likely with Scenarios 2 and 3 being given a weighting of 25%. The weighted NPV for each option is shown below.

Net present value for each option		Scenarios			Weighted NPV	Rank
Number	Option name	Scenario 1	Scenario 2	Scenario 3		
1	New ZS build	51.3 M	0.4 M	134.7 M	59.4 M	3
2	Grid connected battery by third party	60.7 M	1.8 M	178.5 M	75.4 M	2
3	Build grid connected battery	41.1 M	-18.5 M	144.2 M	52.0 M	4
4	NNO - defer ZS build for 3 years	61.3 M	2.6 M	178.9 M	76.0 M	1

**Figure 4 – Houston Kemp scenario analysis output**

## 9. Detailed description and costs of preferred option

The preferred option is to purchase network support from grid connected battery to be owned and operated by an external provider (Firm Power). Firm Power is in the process of securing an ARENA grant to partially fund the project. The proposal is half way through the development and approval phase with construction likely to commence in 12 to 18 months time.

A Network Support Agreement Principles has been agreed between Endeavour Energy and Firm Power in July 2020. The agreement principles states that Endeavour Energy will pay the service provider, Firm Power for network support when required. The network support payments are set to an upper limit of \$1M per year which is less than the annual deferral cost of the zone substation build. The network support payments will start from a low value and will ramp up until it reaches the upper limit as the load at risk increases.

Under the agreement principles, there will be two modes of network support that will be available to Endeavour Energy.

Mode 1 is for reserving energy for network security. In this mode, the battery must reserve the requested energy (MWh) and power output (MVA) for a forecasted peak event day for the purpose of providing network security. Mode 2 is dispatching energy under network contingency. Network contingent events include planned and unplanned outage of network equipment.

## 10. Recommendation and next steps

It is recommended that:

- The project proceeds with Option 2 (purchase network support from an externally owned grid connected battery)
- Continue engagement with Procurement with respect to negotiation of network support agreement with Firm Power.

## 11. Addendum (Revision 1)

### 11.1 Background to Addendum

The recommended option to address South Penrith Capacity Constraints was presented and approved by the IMC in early 2020. The decision as to how this constraint will be addressed has been made, and investment is now progressing inline with this CFI. As such a Grid Battery owned and operated by Firm Power will be completed and connected by the end of calendar year 2022.

Since this decision has been made a number of additional items of scope have been identified to be necessary enabling works for the preferred option. This Addendum details the required additional scope. The estimate for these additional works is \$1.38m and while these costs were not included in the original CFI, the outcome of the original NPV would not have been materially impacted had these works been included at the time.

### 11.2 Additional scope required for the implementation of the preferred option

#### System Configuration Considerations

In reference to **Figure 5**, the Penrith 11kV network is currently operated with only one transformer in service. This is required to keep the network fault level below the ratings of primary network equipment. The two 52MVA transformers operate in a hot-standby configuration with an auto-standby routine providing restoration in the event of a transformer trip. The 11kV busbar is operated in a solid configuration and a single Audio Frequency Injection Cell (AFIC) provides controlled load facilities to all customers. In this configuration, Penrith 11kV is limited to 52MVA.

The connection of the BESS allows additional load to be supplied through the 11kV busbar and feeders while keeping power transformers below required ratings. To mitigate against the risk of cascaded trip events, and to be able to supply loads greater than firm transformer capacity, it is required that both transformers be normally on-line. However, to keep all primary equipment within their allowable fault levels the 11kV busbar will be operated in a split configuration (refer to **Figure 6**). In this configuration the existing Auxilliary Bus and AFIC configuration is no longer suitable as only half of the substation loads will have an AFIC signals available. The lack of suitable AFIC facilities must be addressed.

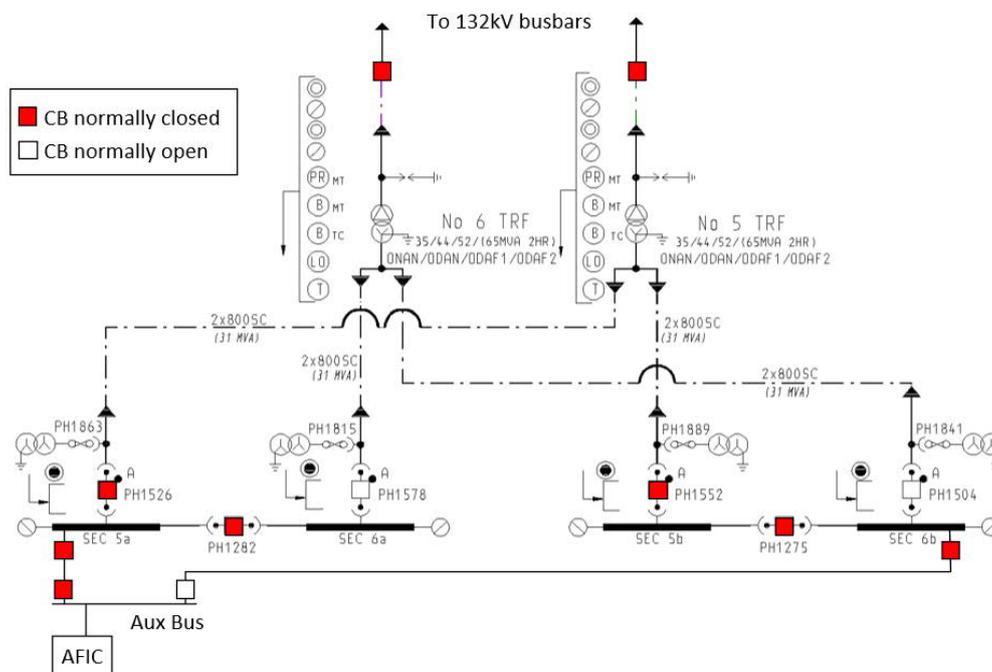
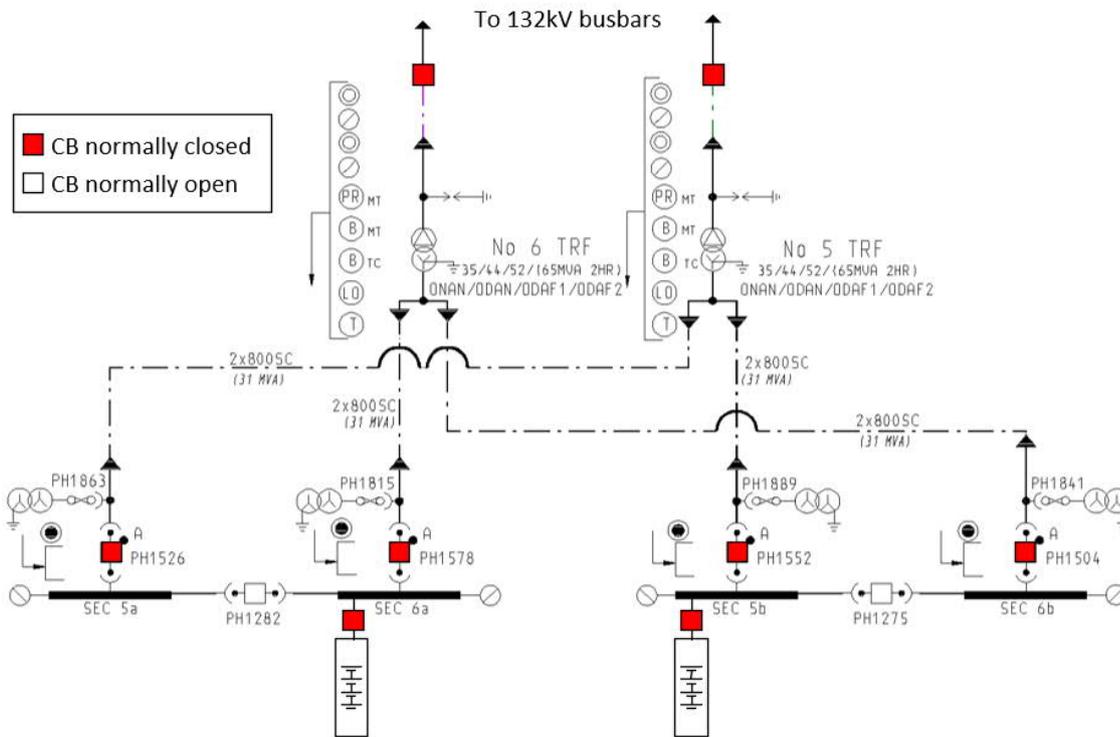


Figure 5 – Penrith TS 11kV transformers and Normal Operating Configuration



**Figure 6 – Penrith TS 11kV transformer and BESS Proposed Operating Configuration**

### Equipment Capability

Endeavour Energy has been advised by BESS provider Firm Power that the 1050Hz signal cannot be presented to the battery due to its equipment capability and immunity requirements. This requirement can be addressed by either the removal of the AFIC signal from the connecting network, or by the installation of filters. Consideration to these options are further discussed below.

### Secondary Systems Configuration

Various SCADA system augments are required in order to facilitate the successful coordination of the BESS control system and the EE substation control system and SCADA. For example, the sharing of CB status, charge/discharge information, voltage setpoints for successful voltage regulation schemes, and coordination and stability for under frequency load shedding schemes that covers all modes of operations.

### Distribution Works

There are no spare CB's at Penrith 11kV for the direct connection of the BESS. As such the connection will be made by first double cabling existing 11kV distribution feeders. To comply with Endeavour Energy Standard MDI0026 additional distribution network automation is required.

### Summary of Identified Need

It is required that Endeavour Energy address the lack of insufficient AFIC facilities at Penrith 11kV following the installation of the BESS, and this should be done in the context of the incompatibility with the BESS. Additionally, secondary systems and distribution automation works required to be funded.

### Strategic considerations to AFIC

At the December 2021 IMC meeting a strategy paper for AFIC decommissioning was presented. The Committee endorsed the proposal to prioritise AFIC decommissioning at specific sites to achieve additional spares, and also to remove AFIC cells as part of Capital Program works where physical space may be constrained. The paper and Committee also noted the wider value benefits of smart meters (including enhanced functionality such as *OffPeak+* and the availability of more granular network data).

### 11.3 Proposed methods to address additional requirements

There were two primary options considered in order to address the insufficient AFIC facilities.

The **first option is to decommission the AFIC** and provide Smart Meters at impacted customer premises. In addition, AFIC initiated streetlight controllers would also be replaced. This option removes the need to duplicate the AFIC system and eliminates equipment incompatibility issues with the BESS. This option is also fully aligned to strategic direction for AFIC endorsed by the IMC at the December 2021 meeting.

The **second option is the duplication of AFIC and the installation of filters**. This alternative option would see the duplication of the AFIC system such that there a unit available for both busbars. As discussed earlier, it is a technical requirement of the BESS that the AFIC 1050Hz signal is not presented to the BESS. If the AFIC system is retained it would be required to filter this signal by either the use of shunt filters or inline filters.

Shunt filters would have to sink enough signal current to lower the signal voltage close to zero at the BESS terminals. In this instance, the BESS terminal are right on the 11kV bar with almost no impedance in between. This would render our AFIC system overloaded and is an impractical solution.

Inline filters are the alternate approach, however the use of these filters are not common practice on 11kV cable feeder connection points. In addition, there can be unintended consequences with passive filters on harmonic performance if not properly designed and it may not be possible to achieve dependable filter performance for all range of operating scenarios.

The duplication of AFIC is also not considered to be strategically aligned to Endeavour Energy's long term objectives (refer previous section). High level costs for this option were considered. The duplication of the AFIC, including the installation of additional auxiliary switch gear was estimated to be in the order of \$350k. The additional cost of passive filters and enclosure requirements is not known with certainty, but is likely to be in the order of \$100k per connection.

While this option may have be technically feasible it is not recommended on the basis of unknown technical risks and costs presented by passive filter equipment, a comparable cost profile and it not being aligned with Endeavour Energy's strategy for Controlled Load facilities.

### 11.4 Detailed description and costs of additional scope for preferred option

The proposed option is to decommission the AFIC equipment at Penrith Transmission Substation 11kV busbar, install alternative controlled load facilities (such as smart meters, and PE cells for street lights) where required, and to complete the required Secondary Systems and Distribution Automation works.

**Table 5** provides the high-level scope of works and cost estimate.

	Description	Cost Estimate (\$)
Decommission AFIC	<ul style="list-style-type: none"> <li>Decommission and remove the Penrith 11kV AFIC;</li> </ul>	\$20k
	<ul style="list-style-type: none"> <li>Facilitate the installation of Smart Meters (or other controlled load facilities) for approximately 6,800 customer connected to the 11kV feeders listed at Appendix A</li> </ul>	\$915k
	<ul style="list-style-type: none"> <li>Facilitate the change of AFIC controlled street light control points in the catchment of Penrith 11kV and surrounding feeders identified at Appendix A</li> </ul>	\$200k
Secondary Systems	Implement required SCADA systems modifications, including: <ul style="list-style-type: none"> <li>RTU and master station integration activities between BESS and Penrith 11kV RTU</li> <li>Configuration, testing and commissioning of AGC services.</li> <li>Coordination with AU013 works for the procurement and implementation of ICCP/DNP3 converters</li> <li>Associated build, test and commissioning</li> </ul>	\$20k
Distribution Automation	Installation of automated distribution equipment inline with Standards (MDI0026). Refer to four DWP scope sheets at Appendix B.	\$172k
Connection works	Coordinate the works required in this CFI with Customer Network Solutions and the timing of 11kV Connection Headworks as per project UIL6048K	\$0
Project Management		\$50k
<b>Total</b>		<b>\$1.38m</b>

**Table 5 – Summary of scope and cost estimate for the recommended option**

This decommissioning of the AFIC must be facilitated before the energisation of the BESS. Accordingly, the timing for the investment is for FY22 and FY23 prior to the end of calendar year 2022. All works should be coordinated with that of Customer Network Solutions branch.

### 11.5 Impact on the detailed costs and benefits model

The costs associated with this CFI Addendum were not foreseeable at the time of recommendation due to the insufficient detail design that resulted in these network need items having been identified. It is also noted that the estimated costs of this work (approximately \$1.38m) are unlikely to have materially impacted the recommended outcome.

## 11.6 Scope Detail A: Feeders nominated for smart meter installation

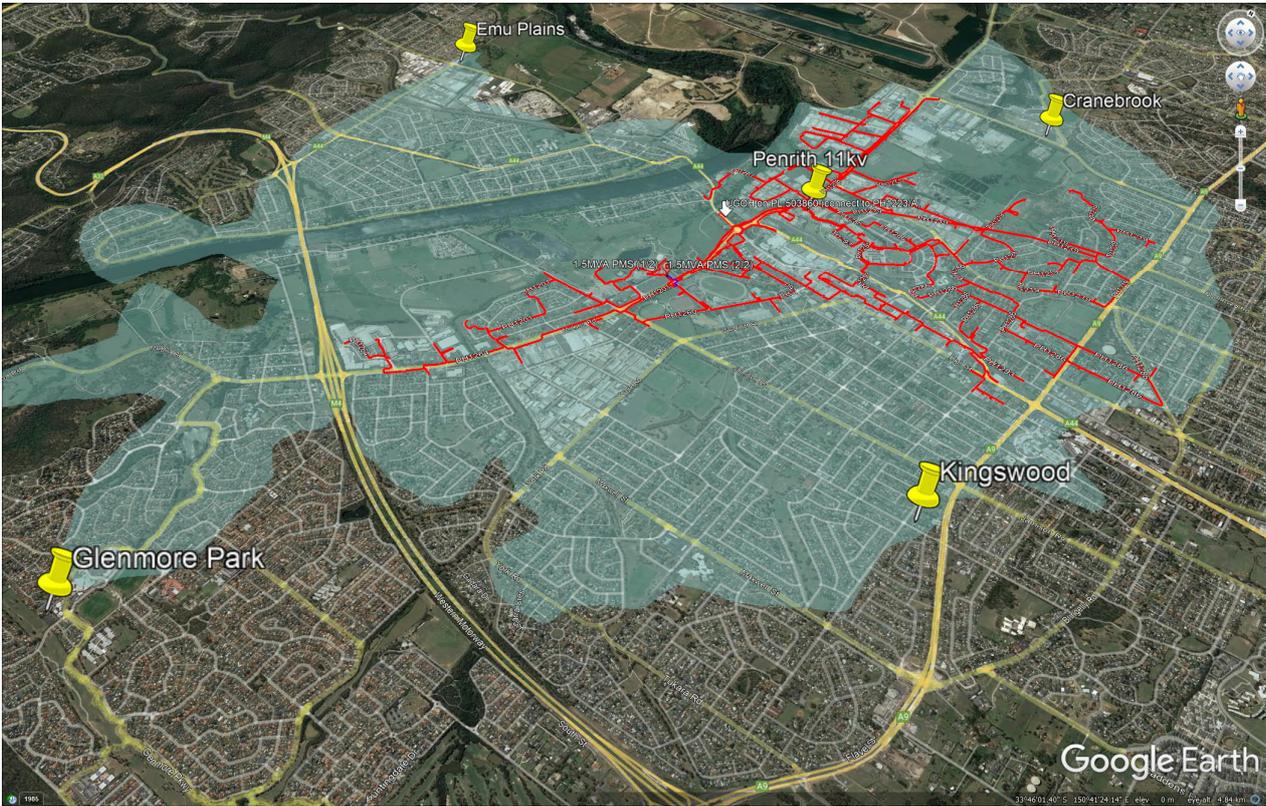
Priority	Substation	Feeder	Count of NMI	Estimated cost	Notes
1	PENRITH 11KV	PH1201	228	\$27,360	
1	PENRITH 11KV	PH1219	699	\$83,880	
1	PENRITH 11KV	PH1230	2	\$240	
1	PENRITH 11KV	PH1260	45	\$5,400	
1	PENRITH 11KV	PH1264	31	\$3,720	
1	PENRITH 11KV	PH1267	2	\$240	
1	PENRITH 11KV	PH1271	4	\$480	
1	PENRITH 11KV	PH1286	379	\$45,480	
1	PENRITH 11KV	PH1290	1	\$120	
1	PENRITH 11KV	PH1293	89	\$10,680	
1	PENRITH 11KV	PH1297	4	\$480	
2	CRANEBROOK	S785	516	\$61,920	
3	CRANEBROOK	C812	220	\$26,400	
3	CRANEBROOK	L528	3	\$360	
3	CRANEBROOK	S786	323	\$38,760	
3	CRANEBROOK	S788	245	\$29,400	
3	CRANEBROOK	S790	0	\$0	
2	EMU PLAINS	C852	457	\$54,840	
2	EMU PLAINS	C857	129	\$15,480	
3	EMU PLAINS	55356	491	\$58,920	
3	EMU PLAINS	55361	364	\$43,680	
3	EMU PLAINS	C869	479	\$57,480	
2	Glenmore Park	S776	428	\$51,360	
3	Glenmore Park	S765	243	\$29,160	Acacia Ave feeder leg only
2	KINGSWOOD	9016	203	\$24,360	
2	KINGSWOOD	9017	90	\$10,800	
2	KINGSWOOD	9022	462	\$55,440	
2	KINGSWOOD	9025	~441	\$52,848	Evan Street feeder leg only
2	KINGSWOOD	9029	578	\$69,360	
2	KINGSWOOD	9033	431	\$51,720	

Notes on priority:

1. Feeders impacted in the system normal configuration. Highest priority.
2. Residential setting feeders that are backfed from Penrith 11kV during contingency switching. Second highest priority.
3. Other residential settings but are the lowest priority.

Also note that the above feeders are also the defined scope for AFIC controlled street light control point replacements.

A geographic overlay is provided overpage.



**Figure 7 – Catchment area impacted by the AFIC decommissioning**

## 11.7 Scope Detail B: Distribution works scope sheets (4 items)

NPR-000532 Penrith BESS

Zone: <b>Penrith, 9769</b>	Item No: <b>MHN04914</b>	Amd No: <b>0</b>
Feeder: <b>PH1208/A – Castlereagh Rd</b>	LG Area: <b>PENCC</b>	
Location: <b>Castlereagh Road, Penrith</b>	Prepared: <b>Gavin De Hosson</b>	

### Reason for Works

Connection headworks required for the grid battery.  
 Replace HV switchgear in Switching Station 2557 with automated switchgear.

### Description Of Works

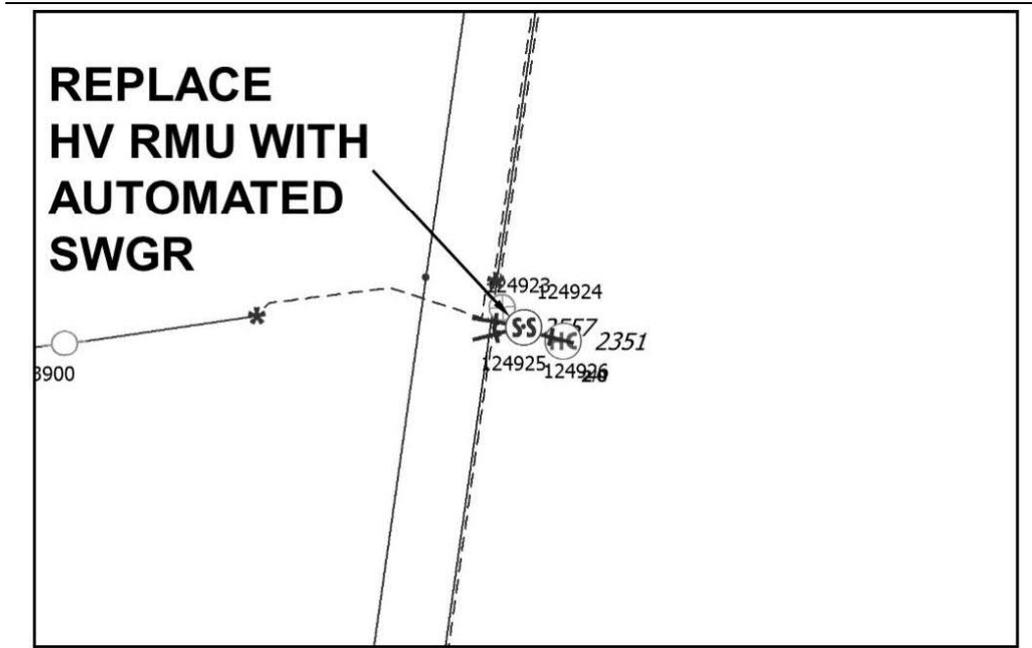
Length (km)

Replace existing HV Sw/Gr in SS 2557 with automated four feeder unit.

Estimated Total Project Cost:

\$54,000

### Remarks



Zone: <b>Penrith, 9769</b>	Item No: <b>MHN04915</b>	Amd No: <b>0</b>
Feeder: <b>PH1208/B – Coreen Ave</b>	LG Area: <b>PENCC</b>	
Location: <b>Castlereagh Road, Penrith</b>	Prepared: <b>Gavin De Hosson</b>	

**Reason for Works**

Connection headworks required for the grid battery.

Replace ABS 48644 with Automated LBS.

**Description Of Works**

**Length (km)**

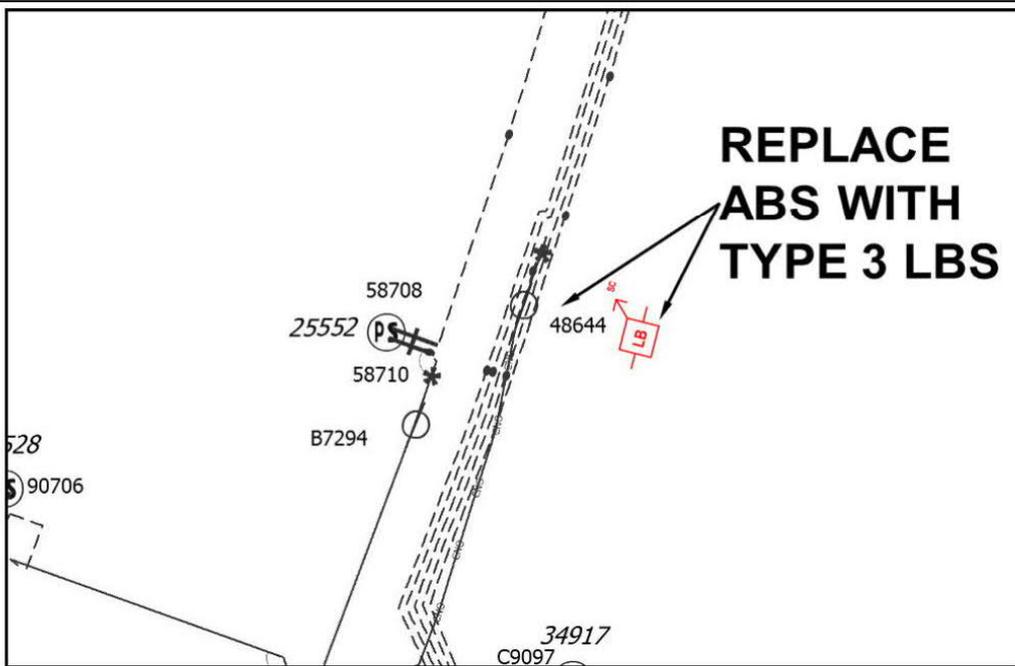
Remove existing ABS 48644.

Install a SCADA controlled LBS (Type 3) in place of the removed ABS as indicated.

**Estimated Total Project Cost:**

**\$40,000**

**Remarks**



Zone: <b>Penrith, 9769</b>	Item No: <b>MHN04916</b>	Amd No: <b>0</b>
Feeder: <b>PH1223/A – Ladbury Ave</b>	LG Area: <b>PENCC</b>	
Location: <b>High Street, Penrith</b>	Prepared: <b>Gavin De Hosson</b>	

**Reason for Works**

Connection headworks required for the grid battery.  
 Replace ABS G4079 with Automated LBS.

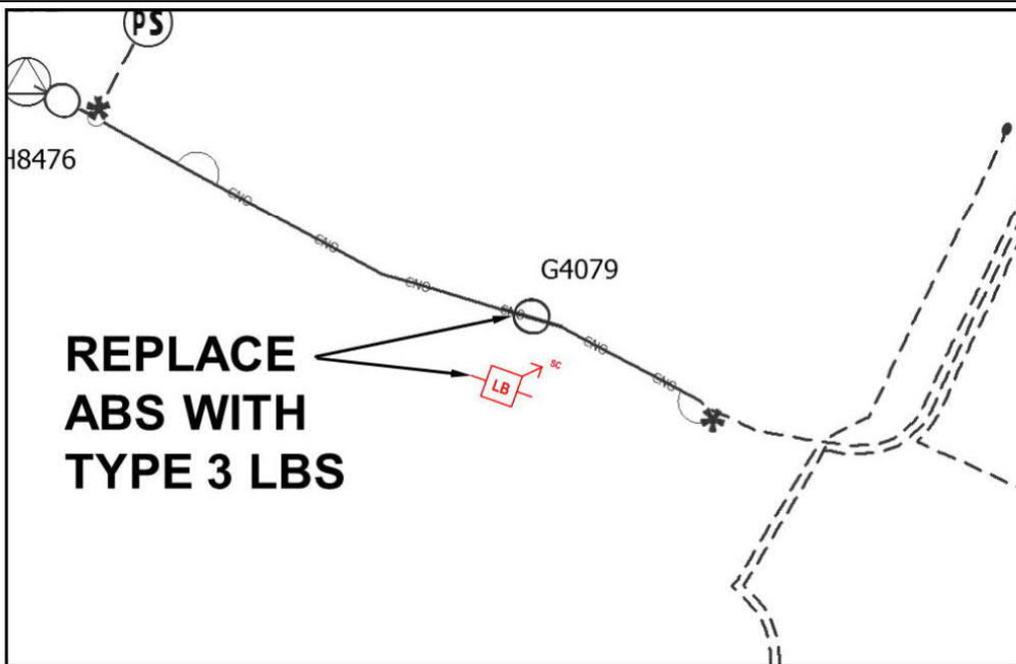
**Description Of Works**

**Length (km)**

Remove existing ABS G4079.  
 Install a SCADA controlled LBS (Type 3) in place of the removed ABS as indicated.

**Estimated Total Project Cost:** **\$40,000**

**Remarks**



Zone: <b>Penrith, 9769</b>	Item No: <b>MHN04917</b>	Amd No: <b>0</b>
Feeder: <b>PH1223/B – Tax Office</b>	LG Area: <b>PENCC</b>	
Location: <b>Combewood Avenue, Penrith</b>	Prepared: <b>Gavin De Hosson</b>	

**Reason for Works**

Conenction headworks required for the grid battery.  
 Replace HV Switchgear in DS 33813 with automated SWGR.

**Description Of Works**

**Length (km)**

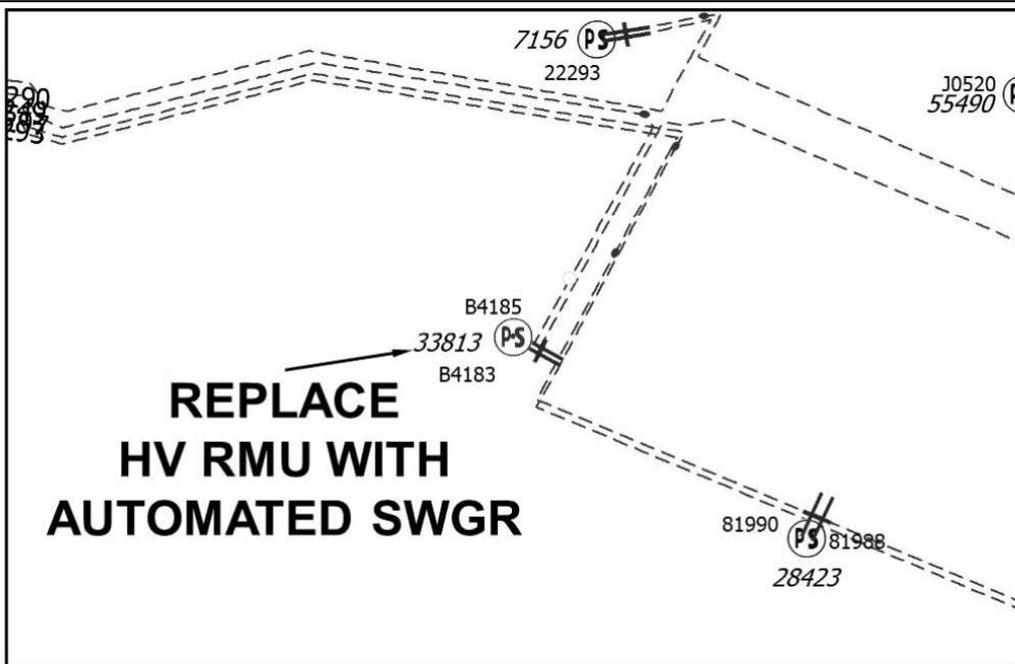
Replace existing HV Sw/Gr in sub 33813 with automated two feeder unit.

**Estimated Total Project Cost:**

**\$38,000**

**Remarks**

This is an existing 2 switch HV unit. Replace with another 2 switch unit, with only ONE switch automated.  
 The switch to be automated must be the switch on cable toward Penrith ZS (i.e. in the current position that switch B4185 is in).



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