Addressing bushfire risk reclassification

Draft Project Assessment Report

19 July 2024

Essential Energy

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1. Executive Summary

This draft project assessment report has been prepared by Essential Energy in accordance with the Regulatory Investment Test for Distribution (RIT-D) requirements, as specified in clause 5.17.4 of the *National Electricity Rules* ("the Rules").

The purpose of this report is to demonstrate the basis for the selection of the preferred option to mitigate the higher levels of bushfire risk in the newly identified bushfire priority zones.

Essential Energy has completed enhanced fire risk modelling across the entire network using the University of Melbourne's Phoenix RapidFire fire consequence model. The outcomes have seen a material shift in where the areas of highest bushfire risk exist on the Essential Energy network.

There is now a need to ensure that the existing standards and practices, for managing the risk of powerline-initiated bushfires, are also applied to the newly identified higher bushfire risk areas.

Essential Energy has determined that there is no viable non-network solution option or Stand-Alone Power System (SAPS) option that could form a signification part of a potential credible option to address the identified need. We are concurrently publishing our notice setting out the reasons why we have determined that an options screening report is not required.

There were also several network-solution options considered in the assessment process including undergrounding, line relocations and deployment of Rapid Earth Fault Current Limiters. Ultimately, three options were determined to be credible in addressing the network need as listed below:

Base case	Do nothing
Option 1	Undertake **standard clear-to-sky (CTS) cutting** treatment of vegetation corridors in all newly identified bushfire priority 1 zones.
Option 2	**CTS** treatment **supplemented** with the **targeted installation** of some high voltage covered conductors **(HVCC).**
Option 3	**CTS** treatment **supplemented** with the **targeted installation** of some Stand-Alone Power Systems **(SAPS).**

The Do-nothing option is not considered credible as it will result in higher than acceptable risk in newly identified higher bushfire risk area of the network, and non-compliances with jurisdictional regulatory obligations. All trees in proximity to powerlines must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and considering the risk profile associated with that location.

Options 1 involves applying the standard approach to vegetation management in bushfire priority areas, which is cutting all the vegetation near network assets to a CTS level in the highest risk areas.

Option 2 is to undertake standard CTS treatment in the majority of newly identified bushfire priority zones, as well as installing HVCC in some specific locations along with implementing slightly narrower CTS corridors in those specific locations.

Option 3 includes undertaking standard CTS treatment in the majority of newly identified bushfire priority zones, as well as removing powerlines and installing SAPS, in locations where it is efficient to do so, and where the impacted customer/s agree to the SAPS replacing the existing grid-connection.

The economic assessment of the credible options is shown in Table 1. Option 3 presents the highest net present value (NPV) of the market benefits considered in our evaluation to date. The assessment period for considering the NPV is 20 years. Market benefits are the risks avoided based on the Phoenix RapidFire fire consequence model which captures risk and costs of bushfire impacts, as well as the expected value of unserved energy which is monetised using the Value of Customer Reliability (VCR). The VCR values used are those published by the Australian Energy Regulator in December 2023.

Table 1: Summary of credible options

Option	Description	Net Project Capital Cost (CAPEX) ($m nominal)	Present Value Benefits ($m real)	Present Value Costs ($m real)	Present Value Net Benefit ($m real)	Benefit cost ratio	Rank
1	Clear to Sky	88.0	345.5	97.0	248.5	3.6	3
2	Clear to Sky with some HVCC	93.1	362.3	100.7	261.6	3.6	2
3	Clear to Sky with some SAPS	89.6	367.7	98.1	269.6	3.7	1

Considering the capital cost, value of market benefits, identified risk and NPV, the preferred option is Option 3.

Sensitivity analysis of uncertainty in the benefits and costs of the model found the Benefit Cost Ratio and Net Benefit remained high. For example, if costs were 40% higher than estimated for all Options the project continued to have a positive Benefit Cost Ratio and Net Benefit. The same is generally true for individual assumption sensitivities (except at extreme values which are unlikely to occur), with some assumptions considered including the vegetation to ignition rate, network annual average vegetation contacts, and vegetation outage duration, amongst other assumptions.

In each scenario considered, Option 3 remained the preferred option, indicating there is a high degree of confidence in this result.

Essential Energy seeks written submissions from interested parties in relation to the preferred option outlined in this document. Submissions are due on or before 30 August 2024. All submissions and enquires should be directed to Essential Energy at reginvestment@essentialenergy.com.au.

The next formal stage of this RIT-D process involves the publication of the Final Project Assessment Report. We currently anticipate that this report will be released by 13 September 2024.

2. Context

About Essential Energy

Essential Energy is a New South Wales (NSW) state-owned electricity infrastructure company which owns, maintains, and operates the electrical distribution networks for much of NSW, covering 95 percent of the state's geographical area. We also own and operate water and sewerage systems in the Broken Hill region, providing services to customers through Essential Water. Our customers rely on us to safely and reliably supply electricity and water services in remote, rural and regional areas of NSW.

Bushfire risk management

Bushfire risk is a category of asset event risk which may result in Essential Energy failing to meet certain elements of the National Electricity Objectives (NEO). Specifically, the risk of a powerline-initiated bushfire caused by Essential Energy assets would result in a material and detrimental impact to our customers in terms of sustained loss of power supply, property and environmental loss/damage, community economic impact and/or personal harm, injury, or death.

At a very foundational level, managing the bushfire risk associated with the electrical network involves the appropriate installation, operation and maintenance of assets (ie: the “pole and wires”) and keeping vegetation clear of these assets.

In the context of this report;

- Bushfire risk does not include damage to Essential Energy assets if a bushfire is started by external factors such as a lightning strike or arson.
- Vegetation management is the risk treatment response this particular project is addressing.

Vegetation management requirements

The management of vegetation in the vicinity of powerlines is mandated by the Electricity Supply Act 1995 (NSW) and Electricity Supply (Safety and Network Management) Regulation 2014 (NSW). Under this Regulation, network operators are subject to direction (i.e. legally compelled) by the New South Wales Minister for Energy to take into account Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets (ISSC3:2016).

To meet Essential Energy’s legally binding requirements to implement ISSC3:2016, Essential Energy determines the appropriate levels of vegetation inspection and treatment activity to be undertaken based on the safety and reliability risk profile in any given location throughout the network.

There is no option to “do nothing” for trees in proximity to powerlines. All must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and considering the risk profile associated with that location.

In areas identified as highest bushfire risk, the required standard involves the creation and maintenance of clear-to-sky vegetation corridors in addition to the horizontal and groundline minimum clearance spaces as defined in ISSC3:2016.

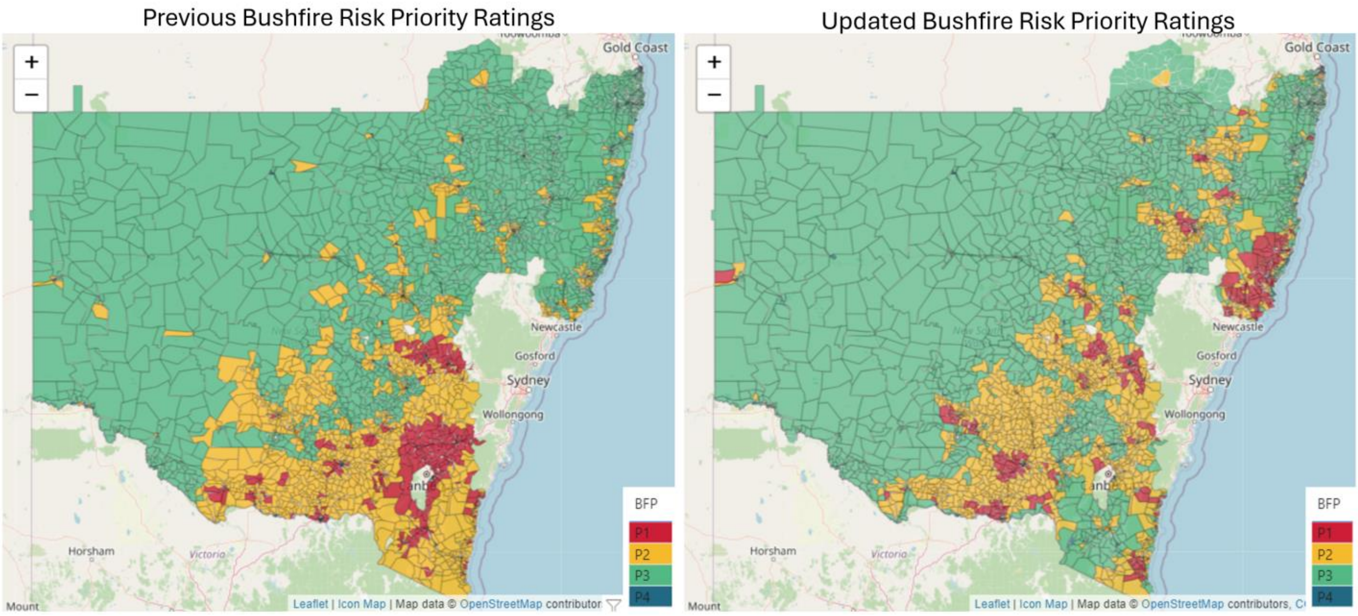
Modelling of highest bushfire risk areas

To meet the requirements of ISSC3:2016 Essential Energy has completed enhanced fire risk modelling across the entire network using the University of Melbourne’s Phoenix RapidFire fire consequence model.

The modelling has resulted in a material shift in where the areas of highest bushfire risk exist on the Essential Energy network – refer to Figure 1. The highest risk zones are designated P1 (priority 1), medium risk as P2, low risk as P3 and urban density areas are P4.

The priority (P) zones represent the relative bushfire risk across the network. P1 zones are those locations that, if a powerline-initiated fire were to start in these areas, it would cause the greatest impact (consequence) in terms of modelled loss of houses, property, and loss of life relative to the other P zones in the network.

Figure 1 Map of the previous and updated bushfire risk priority ratings across Essential Energy



With a deeper understanding of the bushfire risk profile across the network, there is now a need to transition and align our asset management and vegetation management standards to reflect the revised bushfire priority zones.

Enhanced vegetation standards in P1 areas

P1 zones receive a higher level of management in terms of asset and vegetation inspection and treatment. Specifically, in P1 zones Essential Energy implement the following,

- An annual pre-summer bushfire inspection of all P1 assets
- Rectification of all identified items arising from the pre-summer bushfire inspection prior to 1 October each year
- Enhanced construction standards for any new affected assets e.g. the application of low voltage (LV) spreaders
- Increased prioritisation of task rectifications e.g. a maintenance item or vegetation clearance item arising from an inspection
- Reduced rectification timelines for a maintenance item or vegetation clearance item arising from an inspection.
- Creation of “clear-to-sky” (CTS) vegetation corridors in the vicinity of powerlines

There are 7,055km of powerline corridors in these revised bushfire priority 1 (P1) zones, that were not previously P1. Much of the asset-related activity (asset inspection and maintenance) has been transitioned to align with the revised bushfire priority zones as the scope to do so has been manageable, and able to be integrated into the existing cyclic program of works without a material impact.

The remaining transition activity is associated with vegetation management of the corridors, which is the most complex in term of scope, size, community impact and cost to deploy. Specifically, for the newly identified highest bushfire priority areas (P1s), the vegetation standard[1] applicable in P1 areas is the creation and maintenance of CTS corridors wherever vegetation is near powerlines.

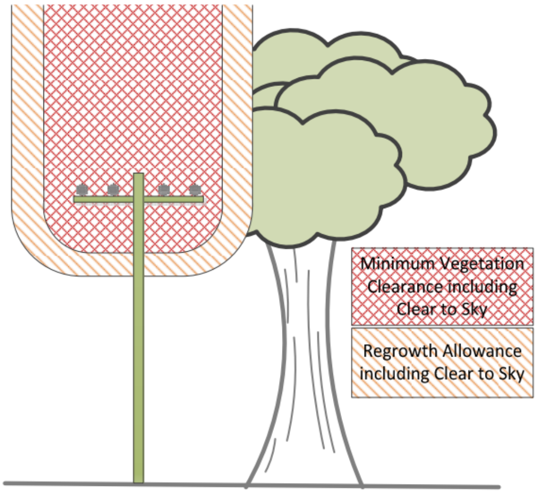
[1] Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets

This will require an extensive uplift in vegetation effort to transition identified corridors to CTS corridors. CTS corridors involve the clearing of vegetation that encroaches into the hashed zones identified in Figure 2 below. At times this can result in the full removal of trees located outside of the clearance corridor where it has been assessed that the trimming of limbs will result in an unstable tree with an increased risk of falling into the powerline.

Figure 2 Extract from ISSC3 Guide for the Management of Vegetation in the Vicinity of Electricity Assets, page 27.

S1 - 3.7 Vegetation above Conductors and "Clear to the Sky" risk reduction strategy.

"Clear to the Sky" vegetation hazard reduction measures involve the practice of removing all vegetation above the Electricity Assets to the width of the minimum Clearing Requirement. This is shown in Figure 7 below.



There are currently 4,206km of powerline bays situated within the new P1 areas where vegetation has been identified that is not currently maintained to the CTS standard.

An assessment of the impact indicates the effort to achieve the once-off transitional cutting to CTS standards, is broadly equivalent to the current vegetation management program in any given year. Once a corridor achieves CTS standard, the ongoing maintenance of this standard is relatively minor.

Another aspect of this project is that the same resource pool (the available vegetation contractor pool in Australia) would be required to undertake both the transitional cutting works and cycle vegetation program works in parallel to each other.

Projections for the duration to complete the transitional cutting works currently sits at approximately eight years, spread over two regulatory periods. This timing is dependent on the rate of expansion of the vegetation contractor resource pool, market forces, workforce efficiency initiatives, and contracting models deployed.

Validation of effort

The scope of the project has been established via desktop analysis using available data. There are 267 affected Vegetation Management Areas [2](VMAs) in the new P1 areas and to assess each of these using qualified vegetation scopers would take at least 2-3 years, at which time the state of the vegetation would have changed given its dynamic nature, weather patterns and growth rates.

[2] A vegetation management area is how the EE network is divided for the purposes of managing the cyclical vegetation treatment program. VMAs are issued to Contractors as a works package and are used for progress tracking and payment purposes.

To support the data-driven scoping exercise, the physical treatment of three “pilot” VMAs to CTS standards has been completed. The three VMAs were selected to represent a high complexity VMA (high tree density), a medium and low complexity VMA. These learnings have then been applied across the full spectrum of impacted VMAs to further inform and refine the scope, potential program costs and a transition plan. The samples chosen included two VMAs on the mid-north coast as this area has been impacted the most by an increased volume of new P1 VMAs and is likely to be most representative of the incremental work to implement the new CTS areas.

Essential Energy’s vegetation transition plan must accommodate the continuation of the existing business-as-usual cycle vegetation program, and the undertaking of this transitional cutting project, whilst also optimising for resource deployment and efficiencies.

3. Identified need

Regulatory compliance obligation

As discussed earlier, the management of vegetation in the vicinity of powerlines is mandated by the *Electricity Supply Act 1995* (NSW) and *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW). Under the Regulation, network operators are subject to direction (i.e., legally compelled) by the New South Wales Minister for Energy to take into account the Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets (ISSC3:2016).

ISSC3:2016 prescribes CTS for areas identified as high bushfire risk.

Coronial enquiry requirement

The NSW Bushfires Coronial Inquiry (2019/20 bushfires) identified Essential Energy’s legacy bushfire risk classification system as “not appropriate or fit for purpose in the lead up to the 2019/20 bushfire season nor at the time the inquiry was heard”[3].

Two recommendations (27 and 28) from the inquiry were for Essential Energy to revise the fire risk modelling and provide a plan to operationalise the outcomes.

Operationalising the outcomes requires our asset management and vegetation management activities to align to the revised bushfire priority zones.

An outcome from the Inquiry is that Essential Energy must write to the Attorney General by 27 September 2024 setting out what steps have been taken to comply with the Recommendations (or why a Recommendation is not being complied with). It is Essential Energy’s intention to comply with the two coronial recommendations, hence the need for this project to proceed.

Further, in early 2024 the Department of Climate Change, Energy, the Environment and Water has issued its National Climate Risk Assessment[4]. This report identifies risks to the provision of essential services and to regional and remote communities arising from climate change. The intention of the work is to inform adaptation measures, such as the shift in treatment of the newly identified highest bushfire risk areas on Essential Energy’s network.

[3] https://coroners.nsw.gov.au/documents/reports/bushfires/NSW-Bushfires-Coronial_Inquiry-2019-2020-Vol-2.pdf

[4] - First pass assessment report (National Climate Risk Assessment - First pass assessment report (dcceew.gov.au)

4. Non-network solutions assessment

In July 2024, Essential Energy published its non-network screening notice. It has determined that there are no non-network options that can form a significant part of any credible solution to appropriately address the project need in a prudent and efficient manner.

Essential Energy's determination was made under clause 5.17.4(c) of the Rules and was published pursuant to clause 5.17.4(d). In accordance with those provisions, Essential Energy will not be publishing a non-network options report in relation to this project.

In summary, Essential Energy's reasons for this conclusion are:

In areas identified as highest bushfire risk, the required vegetation management standard involves the creation and maintenance of clear-to-sky vegetation corridors *in addition* to the horizontal and groundline minimum clearance spaces as defined in ISSC3:2016.

In isolated cases, alternate powerline solutions are deployed to reduce or avoid vegetation treatment where technically and economically prudent to do so e.g., powerline relocations, undergrounding of overhead powerlines, or use of HVCC.

The only alternate *non-network solution* relating to the management of vegetation near powerlines is to permanently *remove* the powerlines and therefore remove the risk of vegetation-initiated powerline bushfires.

The identified line length for this project that is subject to clear-to-sky cutting is 4,026kms. Tens of thousands of customers are reliant on these powerlines, making permanent removal a non-viable solution.

Removal of powerlines is only possible where there is *an alternate source of supply provided* to the customers reliant on that powerline. This is addressed by installing SAPS to each affected customer.

Powerline removal coupled with the provision of SAPS for each impacted customer is not a practicable option to be deployed *at scale* given the 4,026kms of powerlines in the new P1 areas identified as requiring clear-to-sky cutting. Further detail regarding where SAPS can replace vegetation cutting is provided in section 5 'Possible Credible Options' of this report.

Essential Energy's 2024-29 regulatory determination included approval for up to 400 SAPS across the full network footprint. Where identified potential SAPS projects coincide with P1 areas requiring vegetation to be cut CTS, these locations will be removed from this project. Our assessment indicates that less than 1% of the project scope may be addressed by SAPS, hence these have been discounted as a viable non-network solution replacing the need to undertake the proposed 4,026kms of vegetation transition works in the new P1 areas.

5. Possible Credible Options

The base case of 'Do Nothing' reflects the business taking a reactive approach to the increased bushfire risk in the newly identified P1 areas, and just treating them in due course, or dealing with powerline-initiated bushfires as/if they occur. This option is not compliant with our jurisdictional regulatory obligations nor aligns with the safety and network reliability requirements of the NEO, nor the recommendations from the Coronial Enquiry into the 2019/20 NSW Bushfires.

The credible solutions to address the identified need are:

Option 1

Complete the vegetation trimming and tree removals in powerline corridors in the new P1 areas to meet the CTS standards. This is the accepted strategy for P1 areas and would be applied to 100% of the new P1 areas that are currently non-CTS, i.e. 4,026kms of powerline corridors to undergo initial CTS treatment.

This option is considered standard and good practice amongst all Australian electricity network service providers and is the adopted approach in designated high bushfire risk areas.

Option 2

Implement a combination of CTS treatment of vegetation corridors, and the replacing of bare overhead wires with HVCC where it is economically efficient. HVCC is a type of overhead conductor where individual phases are insulated. Being insulated, the potential for ignition is reduced compared to bare overhead wires. HVCC has other benefits such as:

- reduced faults from both vegetation and non-vegetation contact i.e.: bird strikes on the powerline
- the CTS treatment can be done to a slightly reduced standard (the vegetation corridor doesn't need to be quite as wide)

Our analysis to date indicates that this could be technically and economically feasible to deploy for about 50km, which is less than 2% of the target powerline length targeted for CTS treatment, with the remaining 98% requiring the standard CTS treatment.

A key point to note is that where HVCC is deployed, a CTS corridor *must still be established* and maintained to meet our regulatory powerline vegetation clearance requirements, however the corridor can be narrower therefore incurring a marginally lower vegetation treatment cost compared to Option 1.

Option 3 – Preferred option

Undertake a combination of CTS treatment of vegetation corridors, plus removing some bare overhead wires and installing SAPS in locations where it is economically more efficient to deploy this option and the customer has also agreed to the SAPS solution.

SAPS are a type of non-network solution that in recent years has become a viable alternative to traditional poles and wires construction in certain (bespoke) locations. Generally, these systems employ the use of solar panels, batteries and backup diesel generators, however, Essential Energy is technologically agnostic and is also exploring other technologies such as hydrogen.

SAPS are usually viable solutions where there is a long rural powerline (e.g. typically >1km in length) supplying 1 or 2 supply points of low energy usage. Thus, the cost of a SAPS is kept comparatively low due to the low energy requirements, and the economic benefit is larger due to avoided costs of the longer powerline length and the related asset maintenance and vegetation costs over the life of the powerline.

It is also desirable and practical to have a very small number of customers impacted by the powerline removal. Each customer will require their own SAPS (a high cost per location) and each (*every)* impacted customer must provide their explicit informed consent to converting their property, home and/or business to an off-grid SAPS solution before the powerline can be removed. Thus, the smaller the number of impacted customers, the higher the success rate of implementing a SAPS.

Given the above criteria, we have assessed that we could potentially remove 32kms of powerlines in the newly identified higher bushfire risk zones by replacing existing customers' power supplies with a SAPS. If achieved, this represents < 1% of the targeted vegetation corridors that would no longer require CTS treatment.

Whilst Option 1 is the standard approach for the bulk of the program, it does not account for site-specific complexities, such as density of vegetation, existing reliability performance and site access issues. For example, in extremely high tree density locations, the cost benefit of a SAPS installation (Option 3) would include the cost saving from eliminating the need for complex vegetation removal and the ongoing vegetation corridor management. In these cases where the cost benefit outweighs that of standard CTS treatment, a SAPS solution will be pursued with the affected customers.

Our economic analysis confirms Option 3 to be the preferred option over the lifecycle of the assets.

Other options reviewed

The inclusion of undergrounding as part of the solution was assessed and rejected due to the relatively high cost of this solution (cost per km comparison) versus the cost for HVCC and vegetation CTS treatment.

Line relocations were also not considered a viable solution *at scale* due to the remaining need for CTS work unless the line was relocated a significant distance (increasing costs and potentially not technically feasible for many locations), and the potential for community and property owner backlash.

Rapid Earth Fault Current Limiters (REFCLs) were also dismissed as they are not a cost-effective solution and do not avoid the requirement to maintain vegetation clearances from Powerlines. REFCLs would incur significant additional cost compared to all the other potential and assessed options and would not provide the necessary mitigation of risk.

6. Consideration of non-network solutions

Essential Energy has determined that there are no non-network options that can form a significant part of any credible solution to appropriately address higher levels of bushfire risk across the network, because of the reclassification of bushfire risk.

Essential Energy's determination was made under clause 5.17.4(c) of the Rules and is published pursuant to clause 5.17.4(d). In accordance with those provisions, Essential Energy has not published a non-network options report in relation to the proposed risk mitigation works to address the heightened risk rating to satisfy compliance requirements of its updated Bushfire Risk Management Plan. The background to the identified need is also described in our proposed Contingent project[5] for Bushfire Risk Reclassification, which was approved by the AER in its 2024-29 Final Determination for Essential Energy.

Essential Energy expects most of the work to address the need, to involve upgrading of the vegetation clearances around assets in newly identified higher risk areas to meet the clearance standards. This is in addition to some other potential solutions which may make up a minor part of the optimal solutions developed.

Rationale that there are no viable non-network solutions

The management of vegetation in the vicinity of powerlines is mandated by the *Electricity Supply Act 1995* (NSW) and *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW). Under the Regulation, network operators are subject to direction by the New South Wales Minister for Energy to take into account ISSC3:2016.

In meeting the requirements of ISSC3:2016, Essential Energy determines the appropriate levels of vegetation inspection and treatment activity to be undertaken based on the risk profile in any given location throughout the network.

[5] Essential Energy - 8.03 Proposed Contingent Project - March 2024 | Australian Energy Regulator (AER)

There is no option to “do nothing” for trees in proximity to powerlines. All must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and considering the risk profile associated with that location.

In isolated cases, alternate network solutions are deployed to reduce or avoid vegetation treatment where technically and economically prudent and efficient to do so e.g., powerline relocations, undergrounding of overhead powerlines, or the use of HVCC.

The only alternate non-network solution relating to the management of vegetation near powerlines is to permanently *remove* the powerlines and therefore remove the risk of vegetation-initiated powerline bushfires.

The identified line length for this project that is subject to clear-to-sky cutting is 4,026kms with a total of 7,055kms of newly upgraded P1 network that will be treated to adhere to P1 bushfire risk compliance. Tens of thousands of customers are reliant on these powerlines, making permanent removal a non-viable solution.

The case for Stand Alone Power Systems (SAPS)

Because Essential Energy is obliged to supply electricity to customers under the *National Energy Retail Law (NSW)*, removal of powerlines is only possible where there is *an alternate source of supply provided* to the customers reliant on that powerline. This is addressed by installing SAPS to each affected customer. Powerline removal, coupled with the provision of SAPS for each impacted customer, is not a practicable, prudent or efficient option to be deployed *at scale* given the 4,026km of powerlines in the new P1 areas identified as requiring risk mitigation.

- A key limiting factor to the deployment of SAPS is that for any powerline to be removed, all affected customers currently supplied by that powerline must be engaged with and then must provide their explicit informed consent to going off-grid and transitioning to a SAPS.
- For this to happen they must first have the required footprint available on their property to accommodate the solar panel array and ancillary equipment required for a SAPS and provide consent to use this space. Our current experience with targeted SAPS customers is that only ~30%-40% agree to the off-grid SAPS solution when approached.
- SAPS are a bespoke solution, suitable for certain locations such as a long rural powerline i.e.: > 1km in length supplying 1-2 customers, and/or where there are known reliability or access issues. In those cases, they may be the most economically efficient solution.
- Given the relatively high cost to establish a SAPS, the number of locations within the new high bushfire risk zones where SAPS would be a credible substitution option is small, addressing < 1% of the total targeted powerline length where enhanced vegetation standards are required.
- Essential Energy will remove the potential for cost duplication from any location overlap between our approved SAPS program and the newly identified high bushfire risk zones. Furthermore, Essential Energy is committed to maximising the installation of SAPS where prudent and efficient to do so, ensuring the economic analysis for the SAPS captures the cost savings from the avoided vegetation works and the powerline maintenance activities that the removed powerline would have otherwise incurred.

Our initial analysis has revealed a maximum of 103 potential SAPS projects in P1 areas. The resultant maximum impacted line length is 140kms *if all projects were to proceed* and *all projects were in non-clear-to-sky locations*. Using our recent experience where only 30-40% of identified customers may agree to go off-grid and convert to a SAPS, the maximum project impact from SAPS would be:

- Total P1 non-CTS line length; 4,026kms
- Total new P1 area line length; 7,055kms
- Maximum identified length of SAPS (from the 2024-29 price determination) in new P1 areas; 140kms

- % customer agreement for an off-grid SAPS solution; ~40%
- Possible impact of SAPS on this project; (4,026/ 7,055km) x 140km x 40% = 32kms

Therefore, 32kms of powerlines out of a total affected line length of 4,026km may be potentially removed from this project due to SAPS projects proceeding, or < 1% of the total project scope.

Thus, the SAPS option will have a negligible to small impact on the overall project scope and has therefore been discounted as a viable non-network solution in replacing the need to undertake the proposed vegetation CTS works in the new P1 areas.

7. Economic Assessment

Our economic assessment for this draft report is based on existing vegetation contract rates. The existing vegetation contracts will be renewed on or before the 1st July 2026. The outcomes from this market process may materially impact the vegetation treatment costs incurred by Essential Energy.

We anticipate that our Final Project Assessment Report (FPAR) will include further refinements to allow for updated forecasts of contractor rates and other costs most likely to be incurred, such that our cost estimates reflect the most reasonable forecasts at the time of publishing the report.

This program targets the safety and the reliability elements of the National Electricity Objectives (NEO), meaning that these two elements form the basis of the economic benefits our customers will gain from this proposed expenditure.

In this section the economic costs are first discussed followed by the economic benefits, and then a summary of the net economic benefit to our customers is presented.

Program costs

The economic cost of the proposed program are the financial costs associated with the program delivery.

These financial costs have been estimated using two approaches.

1. Unit rate cost (cost model A)

The purpose of this cost model was to establish the cost of undertaking the vegetation treatment using known and available cost data i.e. existing contract rates.

This method weighted each VMA by vegetation treatment complexity and extrapolated the average span rate costs based on these factors.

This method yielded a total vegetation treatment cost of $62.9 million.

2. Data science methodology (cost model B)

The purpose of this cost model was to provide a validation check to cost model A.

A machine learning approach based on random forest regression was used. Random forest is a supervised learning method that can handle both numerical and categorical data, as well as nonlinear relationships and interactions between features.

Data sets were identified that have an influence on the cost of undertaking vegetation works. These include vegetation density, proximity to roadways, roadway speed limits, and terrain characteristics.

The output of this cost model yielded a total vegetation treatment cost of $69.0million.

NOTE: these costs are for the *vegetation treatment* aspect of the overall program of work (tree removals and trimming) and exclude additional costs of the program identified below, and the costs of deploying alternate solutions such as HVCC and/or SAPS.

Vegetation cost model comparison & scenario development

The cost models are within 10% of each other, providing a good level of confidence for the magnitude of the cost that was established using cost model A.

NOTE: Cost model A will the one used to determine the final program cost.

Table 2 shows the high-level expected phasing of the program. Some further "pilot area" CTS treatment is currently being planned for in FY25 (Year 0) and this information will be updated in our final Project Assessment Report.

Table 2 Proposed Vegetation Transition Program

	CURRENT REGULATORY PERIOD					NEXT REGULATORY PERIOD				
Fiscal year	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Transition	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Program completed
Completion	2%	5%	10%	15%	15%	15%	15%	15%	8%	

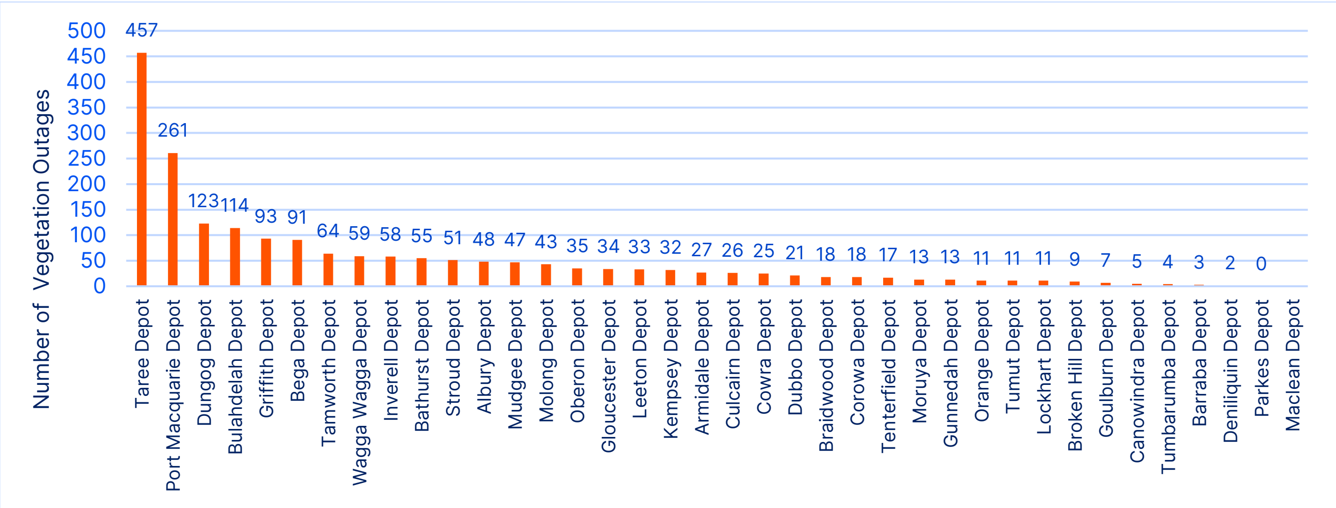
Planned outage costs

Clearing overhanging vegetation above powerlines will require network outages whist the work is being undertaken. Figure 4 below, summarises the expected additional number of outages per depot area to facilitate the CTS vegetation treatment work.

The costs associated with planned outages for vegetation work are broadly made up of two components:

1. Isolation and restoration switching activities (labour) undertaken at the start and end of each planned outage
2. Access permit holders (labour), onsite at the work location for the duration of each outage

Figure 3 Number of network outages required per depot to achieve P1 compliance



Based on the projected volume of outages specific to this works program the total outage cost estimate is $6.4m using standard average planned outage durations for this type of work and the hourly rates for the workers involved.

Other Costs

Additional risk treatment during the transition period

During the proposed 8-year transition program, the existing cyclic vegetation management program must continue in parallel to the CTS transition program. Additional assurance controls will be utilised to ensure both the cyclic cutting program and the CTS transition cutting program are meeting the stated regulatory requirements and project performance milestones. These will include:

- Additional aerial and/or ground-based inspections to identify encroaching vegetation and to validate completed works. Costs to undertake this additional assurance activity will be $200k per year for the 8-year duration of the project. Total cost $1.6m.
- Application of digital data acquisition sources; Essential Energy is adopting emerging data collection methodologies, including satellite technology, to scrutinise risk factors across the network and enhance the decision-making and assurance capabilities of the frontline vegetation management team. Preliminary estimates to acquire this data to facilitate project assurance is in the order of $1.1m over the 8-year period.

Additional OPEX to maintain CTS corridors

The upgrade of 7,055km of network to P1 compliance will incur an incremental cost to maintain the clear-to-sky corridors once they have been established. This extra cost has been derived from existing CTS data and is projected to be $9.1m at the completion of the transition project.

Project management and assurance staff

The transition cutting project will occur over an 8-year period and will be run separately but concurrently with the cyclic inspection and cutting program. Given the complexities and logistics associated with this project, a small, dedicated team will be acquired to manage these works. This will include project management, contract management, project control/reporting and project assurance roles.

This extra cost is projected to be $6.0m over the 8 years of the transition project.

Summary of Incremental Expenditure (through to 2033)

Table 3 Summary of Incremental CAPEX

CAPITAL EXPENDITURE (CAPEX) *COSTS ARE IN FY$25 DOLLARS	
Vegetation transition cutting (creating CTS corridors)	$62.9m
Network outage costs	$6.4m
Avoided CAPEX due to SAPS installations	($1.9m)
Additional aerial and ground-based inspection assurance	$1.6m
Additional digital data acquisition assurance	$1.1m
Project management and assurance staff	$6.0m
Total CAPEX	**$76.1**

Table 4 Summary of Incremental OPEX

OPERATING EXPENDITURE (OPEX) **COSTS ARE IN FY$25 DOLLARS*	
Maintaining clear-to-sky corridors once established	$9.1m
Avoided OPEX due to SAPS installations	($0.6m)
Total OPEX	**$8.5m**

Defining Benefits

The economic benefits attributable to the proposed expenditure are the avoided economic costs relating to the risks that would be mitigated by undertaking this work.

There are two classes of benefits addressed by this project: the mitigated safety risk and the mitigated network reliability risk.

The mitigated safety risk includes a valuation of the quantifiable tangible and direct community impacts from a powerline-initiated bushfire, being injury and/or life loss and property and asset loss. This has been established using the University of Melbourne Phoenix RapidFire bushfire simulation model. The model determines the consequence of a bushfire and provides a quantified value of the loss and damage arising from a powerline-initiated bushfire should one arise from the Essential Energy network.

Separately, we have developed models to determine the likelihood of vegetation contact with Essential Energy powerlines as well as the effectiveness (likelihood reduction) of CTS cutting standards and/or the deployment of HVCC or SAPS.

Combining these models provides a quantifiable safety risk reduction benefit for the deployment of the assessed options.

The mitigated reliability risk is an assessment of the customer impact of power outages that would be *avoided* due to the enhanced vegetation clearing standards applied in the new P1 areas.

Similar to the safety risk benefit assessment, the vegetation contact model (likelihood) has been used to inform the projected avoided outages, whilst the consequence of the avoided outages uses the AER-provided Value of Customer Reliability (VCR) metric.

Combining these provides a quantifiable reliability risk reduction benefit for the deployment of the assessed options.

Bringing together Costs and Benefits

To determine which option delivers the greatest value, a Cost Benefit Analysis has been conducted for each.

- **Option 1** Undertake standard clear-to-sky (CTS) cutting treatment of vegetation corridors in all newly identified bushfire priority zones
- **Option 2** CTS treatment supplemented with the targeted installation of some high voltage covered conductors (HVCC)
- **Option 3** CTS treatment supplemented with the targeted installation of some Stand-Alone Power Systems (SAPS)

The results below show that Option 3 has the highest Net Benefit and Benefit Cost Ratio of the three options over a 20-year time horizon.

Table 5 Summary of Credible Options (20 years)

Option	Description	Net Project Capital Cost ($m nominal)	Present Value Benefits ($m real)	Present Value Costs ($m real)	Present Value Net Benefit ($m real)	Benefit cost ratio	Rank
1	Clear to Sky	88.0	345.5	97.0	248.5	3.6	3
2	Clear to Sky with some HVCC	93.1	362.3	100.7	261.6	3.6	2
3	Clear to Sky with some SAPS	89.6	367.7	98.1	269.6	3.7	1

Option 2 and Option 3 provide better overall risk reduction benefits compared to Option 1 due to the comparable risk reduction effectiveness where HVCC or SAPS would be deployed.

Option 3 has a lower CAPEX cost Option 1 and 2 as this includes the avoided future CAPEX costs arising from the removal of powerlines once the SAPS have been established.

Given the potential significant harm from a bushfire it is not unusual to see relatively high benefit cost ratios from bushfire prevention related Cost Benefit Analysis. As an example:

- Deloitte Access Economics[6] (2014) found a Benefit Cost Ratio of 6.0 for fuel reduction measures in the Blue Mountains to avoid a bushfire.
- Benetton, at al (1997) found for Victoria "… for $1 of public resources allocated to the Fire Management Program, the State benefits by $22 in terms of assets not destroyed by wildfire". [7]

Summary

The preferred option to transition the new highest risk bushfire areas to an enhanced vegetation management standard is to undertake a combination of clear-to-sky treatment supplemented with selective retirement of bare overhead wires and the installation of SAPS.

The application of SAPS would occur on a site-specific basis *where it is economically more efficient to deploy this option* and where the customer has agreed to convert to a SAPS solution.

[6] https://ausfpa.com.au/wp-content/uploads/2016/01/AFPA-DAE-report-Amended-Final-2014-05-27.pdf, Table 7.4, p.44

[7] "An economic evaluation of bushfire prevention and suppression in Victoria. Working paper" 9703: Julia Bennetton, Paul Cashin, Darren Jones and James Soligo – Performance Evaluation Division, Department of Natural Resources and Environment (Vic) June 1997 ISBN 0 7306 6711 1. Also in Australian Journal Of Agriculture and Resource Economics, $2:2 Pp 149-175

8. Publishing of Draft Project Assessment Report for Public Consultation

Essential Energy is publishing this draft project assessment report in relation to the transition of vegetation management standards to new bushfire priority zones project.

We now seek further feedback from stakeholders including registered participants, the Australian Energy Market Operator (AEMO), non-network providers, interested parties and persons on our demand side engagement register. Submissions are due by 30 August 2024.

We will consider all submissions received in response to this draft project assessment report before preparing a final project assessment report. Submissions will be published on our website. If you do not want your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

Submissions

Any questions or submissions regarding this DPAR or requests for further information should be directed to:

Email: reginvestment@essentialenergy.com.au.

Attention: **Pip O'Donnell & Alex Bardon**

9. Glossary

ACRONYM	FULL NAME
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CPA	Contingent Project Application
CTS	Clear To Sky (vegetation removal)
DAM	Digital Asset Management
DPAR	Draft Project Assessment Report
FPAR	Final Project Assessment Report
HVCC	High Voltage Covered Conductor
IPART	Independent Pricing and Regulatory Tribunal
MA	Maintenance Area
NEO	National Electricity Objectives
NER	National Electricity Rules
NPV/C	Net present Value / Cost
OPEX	Operating Expenditure
P1	Priority 1 Bushfire risk area
P2	Priority 2 Bushfire risk area
P3	Priority 3 Bushfire risk area
P4	Priority 4 (Urban) Bushfire risk area
PSBI	Pre-Summer Bushfire Inspection
RIT-D	Regulatory Investment Test – Distribution
SAPS	Stand Alone Power System
VMA	Vegetation Management Area

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