Contingent Project - Bushfire Risk Reclassification

02 December 2024

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Executive Summary

The New South Wales (NSW) Bushfires Coronial Inquiry (Inquiry) - following the Black Summer 2019/20 bushfires - heard evidence in relation to Essential Energy's (and the wider industry's) legacy bushfire risk classification system and whether it was appropriate or fit for purpose in the lead up to the 2019/20 bushfire season[1]. Two recommendations (27 and 28) from the Inquiry were in relation to Essential Energy's revision of bushfire risk modelling. Essential Energy also made submissions regarding its plans to operationalise the outcomes of the revised risk modelling.

The timing of the findings from the Inquiry and the regulatory reset process, meant that there was insufficient certainty around the costs needed to operationalise the outcomes, such that they could be captured appropriately in our regulatory proposal plans for 2024-29. In Essential Energy's 2024-29 Regulatory Determination, the Australian Energy Regulator (AER) accepted our proposed bushfire risk reclassification contingent project[2]. It recognised that a contingent project may be reasonably required to be undertaken in order to achieve the capex objectives over the 2024-29 period.

Essential Energy has now completed the enhanced fire risk modelling across its entire network using the University of Melbourne's Phoenix RapidFire fire consequence model. The outcomes have seen a material shift in where areas of highest bushfire risk exist on the Essential Energy network. Operationalising the outcomes, requires undertaking asset management and vegetation management activities that reflect the requirements of the revised bushfire priority zones.

The additional costs of these activities form the basis for this contingent project.

Following engagement as summarised in section 2.2, in October 2024 we completed the Regulatory Investment Test – Distribution (RIT-D) process with the publication of a Final Project Assessment Report (FPAR). It concluded that the solution to address the increased bushfire risk in these newly identified high risk areas, is to undertake "clear-to-sky" (CTS) cutting of the vegetation corridors in most locations - along with the targeted installation of some Stand-Alone Power Systems (SAPS). CTS treatment is the standard management practice in the highest bushfire risk areas but where it is more efficient to do so - in certain locations (and with the customer/s agreement) - we will remove the powerline and install a SAPS.

Our FPAR[3] included refinements in project cost estimates of approximately 16 percent higher than the Draft Project Assessment Report (DPAR), however, the updated cost benefit analysis (CBA) demonstrates that the preferred option continues to deliver strongly positive net benefits, and remains the top-ranked option.

The nominal capital expenditure component of this project is estimated to be in the order of $115.3M (nominal) through to FY33, however we have excluded the cost of SAPS installations when assessing the incremental cost of the project on our business. The incremental nominal capex is therefore $101.8M and this exceeds the materiality threshold for a contingent project.

The total additional expenditure forecast to complete this project is $98.7M (real FY$25) over the next eight years ($90.0M capex and $8.7M opex). The equivalent revenue shortfall that we are seeking for the 2024-29 period expenditures is $4.4M (nominal). This results in an estimated retail bill impact for a typical residential customer of $1 extra a year on average over the next four years, and for a small business customer, $2 a year.

We have been engaging with our customers and stakeholders on this issue as we have developed the solution, and obtained their support for it. Importantly we leveraged their insights to co-design the community engagement program for this work to minimise the risk of any adverse sentiment.

[1] Inquests and Inquiries into the 2019/2020 NSW Bushfire Season - Volume 2
[2] AER, Final decision Attachment A - Contingent Project Link
[3] Regulatory Investment Test for Distribution Projects (essentialenergy.com.au)

1. Introduction

1.1 Overview

This contingent project application ("the Application") is submitted to the AER to amend the revenue determination that applies to Essential Energy for the 2024-29 regulatory period, and approve the total capital and operating expenditure required to deliver the Bushfire Risk Reclassification contingent project ("the Project") in accordance with the provisions of clause 6.6A.2 of the National Electricity Rules (NER or the Rules).

The Project involves undertaking works in newly identified high bushfire risk areas, such that vegetation corridors are widened to a CTS standard, to comply with jurisdictional regulatory obligations for these bushfire priority zones. In some of these locations we also expect to be able to remove some powerlines and install SAPS instead (avoiding some additional CTS costs), but we will only do this where it is more efficient to do so, and the customer(s) agrees to it. We developed this preferred solution, along with other credible options, and undertook a RIT-D process. No submissions were made in response.

In April 2024, the AER's 2024-29 Determination for Essential Energy accepted the inclusion of a contingent project, which we had included in our Revised Regulatory Proposal. This allows for incremental expenditure to be approved for the Project and the approved revenue for 2024-29 to be amended, subject to satisfying the following trigger events:

1. Based on the findings of the 2022 Updated Phoenix model, Essential Energy completes a review of its Bushfire Risk Management Plan (CEOP8022) that reclassifies one or more bushfire areas of a lower rating (i.e. P2, P3, or P4 areas) to a higher rating compared to the bushfire areas defined in the 2023 fire risk prioritisation zones map contained in CEOP8022, and therefore identifies works required to comply with "ISSC3 (2016) Guide for the Management of Vegetation in the Vicinity of Electricity Assets;" and
2. Essential Energy updates its Bushfire Risk Management Plan (CEOP8022) to reflect the findings of trigger one (1) above and includes the updated plan in its Energy Network Safety Management System (ENSMS) in accordance with the requirements of the Electricity Supply (Safety and Network Management) Regulation 2014; and
3. The AER has not approved a cost pass through application for a regulatory change event or service standard event related to Essential Energy being required to amend its Bushfire Risk Management Plan (CEOP8022) prior to Essential Energy lodging an application with the AER to amend its distribution determination for the Bushfire Risk Reclassification contingent project; and
4. The AER is satisfied that Essential Energy has successfully completed a RIT-D, including an assessment of credible options, that complies with the RIT-D framework under the National Electricity Rules (NER); and
5. Essential Energy provides the AER with written confirmation from a senior manager that the Essential Energy Board has committed to proceed with and complete the Bushfire Risk Reclassification project.

1.2 Structure of this application

The remainder of this Application is structured as follows:

- Chapter 2 describes the Project, our customer and stakeholder engagement to address the identified need, and provides a summary of the completed RIT-D process
- Chapter 3 sets out the regulatory requirements of the Application
- Chapter 4 sets out the incremental forecast capital expenditure requirements

- Chapter 5 covers the forecast incremental operating expenditure requirements through to 30 June 2029, and
- Chapter 6 includes the incremental revenue requirements to the end of this 2024-29 regulatory period as a result of this contingent project.
- Attachment A - Post-Tax Revenue Model (PTRM) – the AER's model used to calculate the required incremental revenue for the balance of the 2024-29 regulatory period - this includes customer bill impact.
- Attachment B – Cost Benefit Analysis – providing information on the options assessed and costs included
- Attachment C:
  (i) Bushfire Risk Management Plan (CEOP8022) - 2023
  (ii) Bushfire Risk Management Plan (CEOP8022) - November 2024
- Attachment D – Vegetation Cost Model Overview
- Attachment E – Confidentiality Claim – for additional supporting information provided to the AER on a confidential basis.

2. Project summary

2.1 Scope

As a result of updated bushfire risk modelling, there are newly identified areas of highest bushfire risk. These areas need to have vegetation managed in compliance with the regulatory requirements for these high bushfire risk areas. To that end, for these new locations, Essential Energy will:

- undertake a combination of CTS treatment of vegetation corridors; and
- remove some bare overhead wires and install SAPS in locations where it is economically more efficient to deploy this option and the customer has also agreed to the SAPS solution.

2.2 Engagement

The need to engage with our customers on this Project has been a deciding factor in Essential Energy taking a deliberative approach to how we address the bushfire risk reclassification issue.

Essential Energy conducted a range of engagement activities to understand the needs and expectations of customers and communities on this issue. Engagement activities have included:

- Two external engagement sessions with the Essential People's Panel - a group of informed customers drawn from across Essential Energy's network footprint. The Panel includes members located in areas impacted by the Project, and includes customers who are also Rural Fire Service volunteers or members of other emergency services organisations. The panel provided feedback on preferred approaches for mitigation of the risks, communication strategies and materials to be used with customers, and options for customers in impacted areas.
- Briefings to Essential Energy's Customer Advocacy Group (CAG) - customer advocates, such as Justice and Equity Centre, Tenants Union, etc. and organisations broadly representing stakeholders within the network customer base, such as NSW Farmers, Business NSW and Caravan & Camping Industry Association NSW. The CAG expressed support for the project and the proposed options, as well as the proposed communications and engagement activities in impacted communities.

- Outreach to State Members of Parliament and elected and executive members of local government authorities in the three pilot areas of the Project. These stakeholders were advised of the project scope and benefits, and were invited to share any insights or concerns.
- The publication of the DPAR and Non-Network Options Screening Report, as part of the RIT-D process, also provided the opportunity for broader stakeholder feedback, although this did not elicit any submissions to the RIT-D.

Essential Energy has incorporated stakeholder feedback into the Project planning and delivery. The feedback has also informed the development of a communication plan which aims to raise awareness, educate, and inform customers and communities about the Project and its impacts. Essential Energy is committed to delivering the Project in a transparent, respectful, and collaborative manner, and to providing case-by-case solutions for customers with unique situations or needs.

Our CAG has been across the development of this work to mitigate bushfire risk in newly identified areas of highest risk. When we published our RIT-D our CAG was also notified in case there were further aspects they could assist with from a stakeholder perspective. In October 2024 we shared information on the draft Contingent Project Application with them. Feedback from the CAG informed our final Contingent Project, which was subsequently approved for submission to the AER, by Essential Energy's Board in November.

2.3 Regulatory test for distribution

Essential Energy completed an assessment of options to address the identified need through the RIT-D process. This assessment commenced in July 2024 and concluded with the release of the FPAR in October 2024. A brief summary of the assessment is set out below.

2.3.1 IDENTIFIED NEED

2.3.1.1 Regulatory compliance obligation

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.

2.3.1.2 Coronial Inquiry requirement

The Inquiry heard evidence in relation to Essential Energy's (and the wider industry's) legacy bushfire risk classification system and whether it was appropriate or fit for purpose in the lead up to the 2019/20 bushfire season[4].

Two recommendations (27 and 28) from the Inquiry were in relation to Essential Energy's revision of bushfire risk modelling. Essential Energy also made submissions regarding its plans to operationalise the outcomes of the revised risk modelling. Operationalising the outcomes requires our asset management and vegetation management activities to align to the revised bushfire priority zones.

In addition, Essential Energy is required, in accordance with Premier's Memorandum M2009-12 - Responding to Coronial Recommendations, to write to the Attorney General (within 6 months) outlining the action taken by Essential Energy to respond to the Findings and Recommendations of her Honour Coroner O'Sullivan following the Coronial Inquiry into the Black Summer Bushfires 2019-2020. Essential Energy complied with this obligation on 27 September 2024 and shared the following further information:

[4] Inquests and Inquiries into the 2019/2020 NSW Bushfire Season - Volume 2

- Essential Energy has completed the transition of the following bushfire risk management activities to reflect the revised bushfire priority zones;
  - The annual pre-summer bushfire inspection program is now occurring in the revised highest bushfire risk areas
  - The asset management systems have been updated to reflect the revised zones
  - Maintenance tasks identified in the revised zones are actioned and prioritised in accordance with policy pertaining to the highest bushfire risk areas.
- Essential Energy is progressing the transition of its vegetation management activities;
  - A vegetation transition project team was established in July 2023 to develop a vegetation transition plan and to obtain the required funding to undertake the works
  - Significant data analysis, scope quantification, pilot area vegetation treatments and estimating models have been progressed and/or completed.

2.3.1.3 Government expectations

In early 2024, the Federal Department of Climate Change, Energy, the Environment and Water issued its National Climate Risk Assessment[5]. 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 governments, industry and communities, and promote adaptation and mitigation measures - such as the shift in treatment of the newly identified highest bushfire risk areas on Essential Energy's network.

2.3.2 OPTIONS CONSIDERED

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 National Electricity Objectives, nor the recommendations from the Coronial Enquiry into the 2019/20 NSW Bushfires.

There were three credible solutions to address the identified need.

2.3.2.1 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. 3,849kms 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.

2.3.2.2 Option 2

Implement a combination of CTS treatment of vegetation corridors, and the replacing of bare overhead wires with high voltage covered conductors (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, e.g. 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)

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

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.

2.3.2.3 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 spur (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 few customers impacted by the powerline removal. Each customer will generally require their own SAPS (a high cost per location) and each 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 66kms 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, as well as powerline maintenance. 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.

2.3.2.4 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). There was also the potential for additional 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 cut or maintain vegetation clearances from powerlines in these new high bushfire risk areas. REFCLs would incur significant additional cost compared to all the other potential and assessed options, and would not provide the necessary mitigation of risk.

2.3.3 FPAR OUTCOME

In July 2024, we published a non-network screening notice and a DPAR for addressing bushfire risk reclassification. This contained the information about the need for the project and the alternative credible options. We did not receive any submissions following publication of these documents.

Since then, we have worked to refine the costs of the credible options using more recent sample data, and more robust methods of estimation for assumptions, inputs and models. This has provided for both increases and decreases in various cost categories, with a 16% overall increase in the estimate of the project expenditures included in the FPAR, since we issued the DPAR. We consider that our forecast increase in costs due to more recent information has been based on reasonable methodologies that reasonably reflect the NER criteria.

2.4 Next steps

Essential Energy is now proceeding to deliver the preferred option identified in the FPAR that satisfies the RIT-D. The next steps involve:

- Assessment by the AER of the required capital and operating expenditure of the project
- The AER approving incremental revenue for the remainder of 2024-29, commensurate with the additional capital and operating costs of the project over that period
- Finalising contracts with relevant suppliers
- Engaging with impacted communities
- Undertaking the works that involve CTS cutting in newly identified high bushfire risk areas, and installing SAPS in those locations where it is economically efficient to do so and the customer(s) agree to it.

3. Regulatory requirements

The regulatory requirements for contingent projects are contained in clause 6.6A.2 of the Rules. Although the AER's 2007 Process Guidelines for Contingent Project Applications are written for transmission businesses, we have endeavoured to align with this, where appropriate.

The key requirements for this Application are outlined in the following sections.

3.1 Amendment of distribution determination for contingent project

Clause 6.6A.2 of the NER sets out the requirements for making an application to amend a revenue determination to include a contingent project.

Clause 6.6A.2(b) sets out the information that the application must provide, specifically:

- an explanation that substantiates the occurrence of the trigger event;
- a forecast of the total capital expenditure for the contingent project;
- a forecast of the capital and incremental operating expenditure, for each remaining regulatory year which the Distribution Network Service Provider (DNSP) considers is reasonably required for the purpose of undertaking the contingent project;

- how the forecast of the total capital expenditure for the contingent project meets the threshold in clause 6.6A.1(b)(2)(iii)) (threshold);
- the intended date for commencing the contingent project (which must be during the regulatory control period);
- the anticipated date for completing the contingent project (which may be after the end of the regulatory control period); and
- an estimate of the incremental revenue which the DNSP considers is likely to be required in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken (which must be calculated in accordance with clause 6.6A.2(b)(7)).

Clause 6.6A.2(f) requires the AER to accept the relevant amounts in the application if it is satisfied that:

- the DNSP's forecast capital expenditure meets the threshold;
- the amounts of forecast capital expenditure and incremental operating expenditure reasonably reflect the capital expenditure criteria and operating expenditure criteria (taking into account the capital expenditure factors and operating expenditure factors in the context of the contingent project); and
- the estimates of incremental revenue and dates are reasonable.

Chapters 4 and 5 of this Application set out the capital and incremental operating expenditure requirements for this contingent project respectively, together with the assumptions and methodology used to arrive at these forecasts.

The incremental revenue required for this project and corresponding customer bill impact is set out in Chapter 6. The remaining regulatory requirements are also addressed in the remainder of this section.

For completeness, Appendix A includes a checklist of the above regulatory requirements.

3.2 Trigger events

The trigger event for the Project has occurred, as substantiated in the following table.

Trigger event	Substantiation
1. Based on the findings of the 2022 Updated Phoenix model, Essential Energy completes a review of its Bushfire Risk Management Plan (CEOP8022) that reclassifies one or more bushfire areas of a lower rating (i.e. P2, P3, or P4 areas) to a higher rating compared to the bushfire areas defined in the 2023 fire risk prioritisation zones map contained in CEOP8022, and therefore identifies works required to comply with "ISSC3 (2016) Guide for the Management of Vegetation in the Vicinity of Electricity Assets"	The risk prioritisation zone map in CEOP8022 shows increased bushfire risk in some areas, compared to 2023, and the forecast costs to comply with ISSC3 are contained within this Project. The 2023 and November 2024 versions of CEOP8022 are included in Attachments C(i) and C(ii), respectively.
2. Essential Energy updates its Bushfire Risk Management Plan (CEOP8022) to reflect the findings of trigger one (1) above and includes the updated plan in its Energy Network Safety Management System (ENSMS) in accordance with the requirements of the Electricity Supply (Safety and Network Management) Regulation 2014	Essential Energy's Bushfire Risk Management Plan (CEOP8022) has been updated and included in the ENSMS, which was provided to IPART's auditors on 14 November 2024.
3. The AER has not approved a cost pass through application for a regulatory change event or service standard event related to Essential Energy being required	Essential Energy has not submitted a cost pass through for these costs.

to amend its Bushfire Risk Management Plan (CEOP8022) prior to Essential Energy lodging an application with the AER to amend its distribution determination for the Bushfire Risk Reclassification contingent project	
4. The AER is satisfied that Essential Energy has successfully completed a RIT-D, including an assessment of credible options, that complies with the RIT-D framework under the National Electricity Rules (NER)	Essential Energy has completed a RIT-D for this project with all relevant information provided to the AER.
5. Essential Energy provides the AER with written confirmation from a senior manager that the Essential Energy Board has committed to proceed with and complete the Bushfire Risk Reclassification project	Confirmation of the Board commitment is attached to this application.

3.3 Project timing

Some preparatory work and planning activities, including customer engagement and co-design activities, have been underway since July 2023. However, Essential Energy intends commencing the work to begin addressing the increased risk of bushfires in January 2026. We anticipate that the program of work will need to continue until FY33 to complete the Project.

	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%	

3.4 Pre-lodgement consultation

Essential Energy and the AER undertook regular meetings as this contingent project was being developed, including through the RIT-D process. Following the completion of the RIT-D, pre-lodgement discussions were held, and the AER was also provided with a draft version of this document.

4. Forecast capital expenditure

4.1 Basis for estimates

This section outlines the forecast capital expenditure for the Project in accordance with the NER. We consider that this amount is reasonably required to undertake the Project, taking into consideration the capital expenditure criteria and capital expenditure factors set out in the NER. Further details of our cost estimates are available in *Attachment G – Detailed Basis of Estimates – Confidential*.

Table 1 below provides a summary breakdown of the capex cost components and the basis of the capex estimates.

Table 1: Breakdown of forecast capex and basis ($M, real FY$25)

COST TYPE	COST ESTIMATE	BASIS FOR FORECAST EXPENDITURE
CTS vegetation work	58.4	Current costs supplemented with forecast market changes
SAPS installations	12.0	Using the SAPS program calculations
Avoided SAPS capex	-2.2	Reflecting removal of lines for SAPS, and lower ongoing line capex
Outages	9.3	Average outage costs associated with vegetation management work around powerlines, by switching segment
Additional inspections	1.6	Average costs per year x8 to validate completion of work during project duration
Additional data	6.4	Average quotes for digital data acquisition applied to new P1 areas, at 3x intervals
Internal labour	13.7	Average labour rates for 10x FTE
Environmental approvals	2.3	Average rates for environmental and Aboriginal heritage assessments applied to length of clearance
Other third party costs	0.5	Actual and forecast costs for services
Total	**102.0**	

4.1.1 CTS VEGETATION COSTS

We based these costs on known and available data, supplemented with more up to date forecasts of expected costs over the life of this project.

The cost to cut the vegetation in the new P1 areas was derived using two separate modelling methods (detailed below). Cost model A weights each vegetation management area (VMA) by vegetation treatment complexity and extrapolates an average span rate cost. The model then uses the actual cost for the four VMAs that have been scoped, and the respective complexity score for every VMA on the network, to scale the cost per non-CTS bay for all the other VMAs across the network.

Cost model B is the check for the bottom up build developed in cost model A. The cost models are within 15% of each other, providing a good level of confidence for the magnitude of the cost that was established using cost model A. Cost model A will be used to determine the final program cost.

4.1.1.1 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, adjusted for estimated changes over the duration of the project.

This method weighted each VMA by vegetation treatment complexity and extrapolated the average unit rate (per meter of required CTS treatment) costs based on these factors.

This method yielded a total vegetation treatment cost of $58.4 million.

4.1.1.2 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 $51.0 million.

NOTE: these costs are for the underlying vegetation treatment aspect of the overall program of work (tree removals and trimming) and exclude additional costs of the Project identified below.

4.1.2 SAPS COSTS

The cost of installing SAPS for this Project ($12M as shown in Table 1) is based on our SAPS program costs as per Essential Energy's 2024-29 Determination. The value reflects 64 SAPS being utilised and removing 66km of powerlines in these new high risk areas. However, the value has been completely excluded from incremental costs and the revenue shortfall, thereby providing further benefits in selecting Option 3 - in addition to it providing the highest net present value (NPV) outcome. This is because funding for up to 400 SAPS was already included in Essential Energy's 2024-29 Determination. We also excluded the SAPS installation costs for the remainder of the project duration (through to FY33), on the assumption that the SAPS program is likely to be assessed at the next reset as an ongoing efficient investment solution. The SAPS forecast to be needed as part of this Project, will form part of the larger SAPS program to be included in Essential Energy's 2029-34 Regulatory Proposal.

4.1.3 AVOIDED SAPS COSTS

The impact of this additional CTS work in the impacted VMAs, has been captured in our assessment of which locations stack up for a SAPS. There are now more sites, where SAPS installations are likely more economically viable, in these newly identified high risk areas. With the installation of SAPS (and the removal of the grid-connecting line), we estimate that CTS cutting will not be needed for 66km, thereby reducing the capex cost of this Project. In addition ongoing capital expenditure on those lines will no longer be needed.

4.1.4 OUTAGE COSTS

Clearing overhanging vegetation above powerlines will require network outages while the work is being undertaken. We have estimated the increase in outages needed to complete this work by switching segment, and applied average labour costs per vegetation outage, using actual cost data over the last three years.

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 for the duration of each outage, who must maintain regular visual and audible contact between the Access Permit (AP) recipient and those signed onto that AP.

These additional outages are not able to be absorbed and facilitated with current resource constraints.

There are also other costs associated with working near the network to treat vegetation, that include the use of live-line crews, managing complaints, obtaining a notice of entry (including at times engaging the police) and managing incompatible tree removal refusals. Overheads have therefore been applied only to this item, to reflect the increased level of business activities needing to be done across multiple areas of the business, and aligned to the expansion in the number of outages needed to complete this Project.

4.1.5 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 inspections which will identify vegetation incursions in VMAs that are deferred due to the labour-intensive nature of the high priority CTS work. Essential Energy needs to manage the bushfire risk to a level of 'So Far as Is Reasonably Practicable' (SFAIRP) in all VMAs whilst the business is in a period of transition. Costs to undertake this additional assurance activity will be $200,000 per year for the 8-year duration of the project. Total cost $1.6m.
- Essential Energy will use advanced digital twin modelling techniques to model risk associated with vegetation contacts. This will assist with the prioritisation of risk mitigation activities that are required to occur throughout the transition. Risk analytics will be supported by strategic digital twin data acquisition at intervals throughout the transition. An interval approach with digital data acquisition activities occurring in year zero, year three and year six of the transition, will enable risk differentiators, such as growth rate and site access, to be monitored and treatment plans to be modified as necessary.

4.1.6 INTERNAL LABOUR

The CTS transition program will occur over an 8-year period and will be run separately but concurrently with the cyclic vegetation 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 a planning officer, compliance supervisor, reporting officer, five technical officers to co-ordinate outages and resolve complex customer interactions, an environmental specialist and a resource to successfully deliver the Communications and Stakeholder Engagement Plan for the project. For estimation purposes we have calculated these additional costs using a typical technical officer rate, from the existing 2021 Essential Energy Award without any network or corporate overheads applied.

4.1.7 ENVIRONMENTAL APPROVALS

The upgrade of 7,508km of network to P1 compliance will require tree removals and, in some cases, where considerable tree removal outside the previously cleared powerline corridor is required, an Environmental Impact Assessment (EIA) will need to be prepared to meet statutory obligations.

In such situations, the EIA, most likely in the form of a Review of Environmental Factors (REF), will likely need to be supported by an ecological impact assessment. Depending on the level of existing disturbance, landscape characteristics, and location relative to known Aboriginal objects and places, an Aboriginal heritage assessment may also be required. We have relied on advice from our Environmental team, using typical assessment costs and applied assumptions to how many instances that these are likely to be needed throughout the Project.

4.1.8 OTHER THIRD-PARTY COSTS

There are other third-party costs associated with this program of work. Essential Energy has already incurred some fees, and over the course of this project there will be further costs incurred.

These costs to date have included legal advice to modify existing vegetation contracts so the additional CTS vegetation treatment could begin in FY25, and reviewing of various documents for regulatory purposes.

Essential Energy sourced an independent industry review of the vegetation management sector, and will require a third-party to provide further analysis of the sector to support the contract renewals in light of this CTS work.

In addition, there will be costs associated with community engagement and social licence, such as sponsorship and advertising costs that will support the proactive community engagement necessary for the vegetation work.

4.2 Capex forecasts by year

Table 2 below shows the forecast capex (real FY$25) of this project by regulatory year, for this regulatory period.

Table 2: Capex over 2024-29 ($M, real FY$25)

COST TYPE	2024-25	2025-26	2026-27	2027-28	2028-29	2024-29
CTS vegetation work	1.0	2.7	5.5	8.4	8.6	**26.2**
Avoided SAPS	0.0	0.0	-0.1	-0.2	-0.3	**-0.6**
Network outages	0.2	0.3	0.8	1.0	1.3	**3.6**
Additional inspections	0.0	0.1	0.1	0.2	0.2	**0.7**
Additional data	1.3	0.0	1.3	0.0	1.3	**3.8**
Project and assurance staff	1.5	1.5	1.5	1.5	1.5	**7.5**
Environmental approvals	0.0	0.1	0.3	0.3	0.3	**1.1**
Other third party costs	0.1	0.1	0.1	0.1	0.1	**0.3**
Total	4.1	4.7	9.5	11.3	13.1	42.6

4.3 Capex threshold

Clause 6.6A.1(b)(2)(iii) of the NER specifies that the proposed contingent capex must exceed either $30 million or 5% of the value of the annual revenue requirement (ARR) for the DNSP for the first year of the relevant regulatory control period – whichever is larger.

For Essential Energy, FY25 is the first year of the 2024-29 regulatory control period. The AER has determined that the ARR for this first year is $1,145.6 million (nominal smoothed) – 5% of that is $57.3 million. Therefore, the applicable threshold for a contingent project is $57.3 million. As the estimated incremental capital cost of the Project is $101.8 million (nominal), it satisfies the threshold requirements of clause 6.6A.1.

4.4 Conclusion

Essential Energy's nominal capex forecast for this project is well in excess of the value to reach the materiality threshold for this contingent project. It is reasonable that our 2024-29 Determination revenue is amended to reflect the additional costs that we will need to incur to undertake this Bushfire Risk Reclassification work.

5. Forecast incremental operating expenditure

5.1 Basis for estimates

The forecast operating expenditure for this project is made up of:

- an increase in ongoing cyclical vegetation maintenance costs, needed to address the increased vegetation clearances required for P1 areas; and
- a reduction in ongoing maintenance costs due to removal of powerlines when SAPS are installed

5.1.1 ADDITIONAL ONGOING VEGETATION MAINTENANCE

Essential Energy is required to maintain vegetation corridors around network assets, to mitigate the risk of vegetation impacting on those assets and resulting in bushfires. The newly identified P1 areas that will be CTS, need their vegetation corridors to be kept clear to a higher standard than previously, to comply with the P1 vegetation clearance standards. This means that the ongoing maintenance costs (opex) is incrementally higher because of the bushfire risk reclassification.

For these new P1 areas, the regrowth cycles vary from 24 to 48 months. The incremental cost increase has been calculated as a proportion of the existing contracted cost to maintain these VMAs. This accounts for the additional work required to maintain the increased vegetation volume associated with the ongoing maintenance of the overhang space.

Each of the impacted VMAs have been allocated a maintenance cycle based on the expectation of when they will need trimming again following the initial CTS cutting. We have incorporated costs based on project phasing and captured only the incremental cost of CTS maintenance compared to the previous vegetation maintenance level, to avoid any duplication of costs with underlying vegetation maintenance cycle work.

5.1.2 AVOIDED MAINTENANCE DUE TO SAPS

The installation of a SAPS and removal of powerlines, means that there is avoided operational expenditure associated with maintaining the powerline, as well as cyclical vegetation maintenance around those powerlines. Based on the removal of 66kms of powerlines for 64 SAPS installations, we have estimated opex savings totalling $0.7M over the project period.

5.2 Incremental opex forecast for 2024-29

Table 3: Incremental opex 2024-29 ($M, real FY$25)

COST TYPE	2024-25	2025-26	2026-27	2027-28	2028-29	2024-29
Extra cyclical CTS vegetation maintenance	0.0	0.0	0.2	0.4	0.7	**1.3**
Avoided opex from SAPS	0.0	0.0	0.0	0.0	-0.1	**-0.1**
Total opex	0.0	0.0	0.1	0.3	0.7	1.2

5.3 Conclusion

The opex for this project is incremental to the opex approved by the AER in its 2024-29 Determination, because the activities were not captured in Essential Energy's opex forecasts, and would not be incurred other than for undertaking this Bushfire Risk Reclassification work.

6. Incremental revenue requirements

6.1 Weighted average cost of capital (WACC)

Essential Energy has undertaken revenue modelling using the 2024-29 PTRM provided by the AER in April 2024, which included the allowed rate of return or WACC, in accordance with clause 6.5.2 of the NER. We expect that this model will be updated by the AER in March or April 2025 to reflect changes in the WACC due to updated cost of debt values, and this will be used by the AER in their determination of this contingent project.

6.2 Depreciation

We have calculated depreciation in accordance with clause 6.5.5 of the NER. Following discussions with the AER, Essential Energy has included the capital costs of this project into the 'Distribution lines & cables' asset class. This is on the basis that when standard line augmentation is undertaken vegetation clearance is included as part of that capex project, and depreciated over the life of the line. This work will therefore be depreciated using the standard asset life (53.8 years) and the standard tax life (45.0 years) of distribution lines and cables. This results in a long cost recovery period and a lower customer bill impact.

6.3 Incremental revenue requirements to end of 2024-29

On the basis of the forecast costs contained in this application, from 2025-26 we are seeking the AER's approval to increase our ARR for the 2024-29 regulatory period. This increase in revenue only reflects the incremental capex and opex of this Project through to June 2029, and excludes the cost of installing SAPS as part of this solution, as the funding for the SAPS program has already been included in the 2024-29 Determination. We have also removed this for the next regulatory period on the assumption that these SAPS installation costs will form part of the broader ongoing SAPS program. It also includes avoided costs due to the preferred solution that includes SAPS – for reduced vegetation cutting, and maintenance costs.

It has been modelled using the PTRM contained in Attachment A. There was no need to use the AER's roll forward model for the incremental revenue requirements, as there were no material Project expenditures in the last regulatory period. We are anticipating that the AER's decision on our ARR amendment due to this Project, will be made in time for our 2025-26 Pricing Proposal.

Table 4 below shows the incremental ARR needed during 2024-29, as a result of undertaking this Project.

Table 4: Proposed incremental revenue for 2024-29 ($M, smoothed nominal)

ARR (SMOOTHED REVENUE)	2024-25	2025-26	2026-27	2027-28	2028-29	2024-29
2024-29 Determination	1,145.6	1,187.8	1,254.2	1,324.2	1,398.1	**6.309.9**
Plus incremental revenue for this Project	0.0	1.0	1.1	1.1	1.2	**4.4**
Updated ARR	1,145.6	1,188.9	1,255.2	1,325.3	1,399.3	**6,314.3**

6.4 Customer bill impact

Based on the forecast ARR adjustments, a typical residential customer will see an average annual increase in their retail electricity bill of $1 per year, over the next four years. For a typical small business customer, this increase is $2 a year on average.

Appendix A: Compliance checklist

The purpose of this table is to demonstrate compliance of this application with the contingent project application information requirements specified in clause 6.6A.2(b) of the Rules.

Table 5: Check against NER contingent project requirements

NER CLAUSE	REFERENCE
1) an explanation that substantiates the occurrence of the trigger event;	Section 3.2 and Appendix B
2) a forecast of the total capital expenditure for the *contingent project;*	Executive Summary and Section 4.3
3) a forecast of the capital and incremental operating expenditure, for each remaining *regulatory year* which the *Distribution Network Service Provider* considers is reasonably required for the purpose of undertaking the *contingent project;*	Section 4.2 and 5.2
4) how the forecast of the total capital expenditure of the *contingent project* meets the threshold as referred to in clause 6.6A.1(b)(2)(iii);	Section 4.3
5) the intended date for commencing the *contingent project* (which must be during the *regulatory control period*);	Section 3.3
6) the intended date for completing the *contingent project* (which may be after the end of the *regulatory control period*); and	Section 3.3
7) an estimate of the incremental revenue which the *Distribution Network Service Provider* considers is likely to be required to be earned in each remaining *regulatory year* of the *regulatory control period* as a result of the *contingent project* being undertaken as described in subparagraph (3), which must be calculated: (i) in accordance with the requirements of the *post-tax revenue model* referred to in clause 6.4.1 (ii) in accordance with the requirements of the *roll forward model* referred to in clause 6.5.1(b) (iii) using the *allowed rate of return* for that *Distribution Network Service Provider* for the *regulatory control period* as determined in accordance with clause 6.5.2 (iv) in accordance with the requirements for depreciation referred to in clause 6.5.5; and (v) on the basis of the capital expenditure and incremental operating expenditure referred to in subparagraph (b)(3)	Section 6.3

Appendix B: Board commitment

2 December 2024

I confirm that the Essential Energy Board, at its meeting on 27 November 2024, resolved to approve:

Committing to proceeding with and completing the Bushfire Risk Reclassification Project.

[redacted]

John Cleland
Chief Executive Officer

Appendix C: Compliance with 5.17.4(z)

Essential Energy makes the below statement for the purposes of complying with clause 5.17.4(z) of the National Electricity Rules.

Essential Energy confirms that since it published its Final Project Assessment Report, as part of the Regulatory Investment Test for Distribution (RIT-D) for addressing Bushfire Risk Reclassification on its network, there has not been any material changes in circumstances that would warrant a re-application of the RIT-D and, accordingly, Essential Energy does not propose to take any further actions.

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