Increase to minimum wood pole interventions

Pass-through application

March 2022

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1 Summary

Over the last number of years, our wood pole management practices have been subject to internal and external review. The Australian Energy Regulator's (**AER**) recent final determination recognised these reviews, and accepted the need for an increase in our wood pole intervention volumes over the 2021–2026 regulatory period.

Subsequent to the AER's final determination, Energy Safe Victoria (**ESV**) issued a notification under section 109 of the *Electricity Safety Act 1998 (Vic)* (Electricity Safety Act) that required amendments to our bushfire mitigation plan (**BMP**) to specify a minimum volume of wood pole interventions. These minimum intervention volumes are shown in table 1.1, and represent more than a 50% uplift on the volumes allowed for in the AER's final determination.

Table 1.1 Wood pole interventions

Description	Total interventions
AER: final determination	22,361
ESV minimum: revised BMP (in response to section 109 notification)	34,650
Incremental volumes (1)	**11,060**

Source: Powercor BMP (revision 9.2) and AER final determination

Notes: (1) The incremental volumes for the purpose of this pass-through application are less than the difference between the AER's final determination and our revised BMP due to a 6-month difference in the relevant periods (i.e. the AER's final determination covers the financial years 2021–2026, whereas our BMP reflects the calendar year period 2022–2026).

On 23 December 2021, ESV provisionally accepted our revised BMP. Under section 83BB of the Electricity Safety Act, there is no distinction between an accepted or provisionally accepted BMP with respect to our compliance obligations (i.e. we are subject to the same penalties for non-compliance with a provisionally accepted BMP as per a 'unconditionally' accepted BMP).

This application, therefore, sets out the incremental costs in each year of the 2021–2026 regulatory period that we will likely incur as a result of complying with our revised BMP, and the proposed positive pass-through amount passed through to customers.

In developing the likely costs we will incur in delivering the minimum required wood pole intervention volumes, we determined a unit rate based on a market tender process for the provision of pole replacement labour services. These rates are consistent with the average of recent historical data published in our regulatory information notices (**RINs**).

Our forecast also includes a negative adjustment to remove any overlap in our pass-through application with the pole-top structures forecast separately funded through the AER's final determination.

A summary of the total cost associated with delivering the minimum incremental volumes now specified in our revised BMP is outlined in table 1.2.

Table 1.2 Proposed positive pass-through amount ($ million, 2021)

Intervention	FY22	FY23	FY24	FY25	FY26	Total
Proposed positive pass-through amount	12.4	24.9	25.0	25.2	25.4	112.8

Source: Powercor cost model, MOD.01 [commercial-in-confidence]

In total, the incremental bill impact of our pass-through application on the typical residential customer is around $2.60 per annum over the remainder of the 2021–2026 regulatory period.

2 Background

Poles are essential to an overhead electricity distribution network. Their basic function is to support overhead electrical conductors and other pole mounted assets, and to provide safe clearance from the ground and other adjacent objects (including vegetation).

This section provides an overview of recent reviews of our wood pole management practices, and discusses the recent request from ESV that requires us to revise our BMP to specify a minimum number of wood pole interventions.

2.1 ESV reviews of our wood pole management practices

Since 2019, ESV has undertaken two reviews into the sustainability of our wood pole replacement practices. The first review focussed on any immediate risks to the public from the condition of our poles in the south-west of Victoria, whereas the second considered the longer-term impacts of our existing management practices.

ESV's second report concluded that the improvement we were making to our wood pole management systems would, when fully implemented, deliver sustainable safety outcomes to the community.

2.2 AER final determination

The AER's final determination was published in April 2021, and accepted the need for an increase in our pole intervention volumes. In particular, the AER recognised ESV's reviews and subsequent recommendations, and acknowledged the significance of these recommendations in managing safety risk.

The AER, however, did not accept our wood pole intervention forecasts. The AER's stated reasons included that our enhanced pole calculator—our field tool used to determine the pole condition and the intervention required—was not yet appropriate as a forecasting method.

The wood pole intervention volumes approved by the AER in its final determination are shown in table 2.1.

Table 2.1 Wood pole interventions: regulatory proposals and AER decisions

Description	Reinforcements	Replacements	Total interventions
Powercor: original proposal	21,723	18,892	40,615
AER: draft determination	n/a	n/a	16,969
Powercor: revised proposal	10,838	17,987	28,825
AER: final determination	9,164	13,197	22,361

Source: Powercor regulatory proposals and AER draft and final determinations
Notes: Total interventions include both replacements and reinforcements, and faults.

2.3 ESV section 109 notice requesting revisions to our BMP

On 27 September 2021, ESV requested revisions to our BMP under section 109 of the Electricity Safety Act.[1] The stated purpose of ESV's request was to address concerns held by ESV that our current wood pole management practices will not achieve sustainable and safe outcomes for the Victorian community, particularly in hazardous bushfire risk areas (**HBRA**).

The revisions to our BMP required by ESV included the following:

1 ESV, *Request to Powercor under section 109*, 27 September 2021.

- a commitment to undertake a minimum of 34,650 wood pole interventions during the period commencing on 1 January 2022 and ending on 31 December 2026 (inclusive), including:[2]
  – a minimum of 25,241 wood pole interventions in HBRA and/or electric line construction areas (with a minimum of 13,614 of these interventions to be replacements)[3]
  – replacement of not less than 3,519 reinforced wood poles
- for the purpose of meeting the commitments above, wood poles must be selected for intervention by applying the following principles:
  – priority will be given to wood poles in worst condition, or which pose the greatest bushfire danger
  – interventions will occur throughout the period from 2022–2026 (inclusive)
  – selection will occur in accordance with our policies, which are to be specified in our BMP for acceptance by ESV.

ESV's notice also highlighted that under section 110 of the Electricity Safety Act, failure to submit a revised electricity safety management scheme on request carries penalty units in the case of both a natural person and a body corporate.

2.4 Our revised BMP

Under section 113A of the Electricity Safety Act, our BMP must be in a form approved by ESV.

Under section 113B(2) of the Electricity Safety Act, we must also comply with our accepted BMP (and failure to do so carries a maximum penalty of 1,500 penalty units).

On 12 November 2021, we submitted our revised BMP to ESV.[4] In consultation with ESV during their assessment process, additional minor revisions were provided.

On 23 December 2021, ESV provisionally accepted our revised BMP under section 83BF of the Electricity Safety Act.[5] This acceptance was provisional pursuant to additional requirements outlined in a further section 109 notice (discussed below).[6]

Under section 83BB of the Electricity Safety Act, there is no distinction between an accepted or provisionally accepted BMP with respect to our compliance obligations. That is, we are subject to the same penalties for non-compliance with a provisionally accepted BMP as per an accepted BMP. Therefore, consistent with ESV's section 109 notice and our obligations under the Electricity Safety Act, our revised BMP compels us to undertake the interventions specified in table 2.2 over the five-year period from January 2022 to December 2026.

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2 ESV's minimum required interventions in HBRA (including replacement specifications) sum to less than the total overall minimum number of interventions. ESV listed these 'sub-specifications' as minimum requirements, and accordingly, necessitates our forecasts being above these to comply with the total intervention target.

3 We also refer to electric line construction areas as bushfire construction areas (**BCA**).

4 Powercor, *BMP (revision 9.2)*, 12 November 2021.

5 ESV, *Provisional acceptance of Powercor's BMP (revision 9.2)*, 23 December 2021.

6 ESV, *Further request to Powercor under section 109*, 23 December 2021.

Table 2.2 Minimum wood pole interventions required under our BMP

Intervention type	2022	2023	2024	2025	2026	Total
Replacements	4,153	4,155	4,153	4,153	4,153	20,767
Reinforcements	2,777	2,775	2,777	2,777	2,777	13,883
Total	**6,930**	**6,930**	**6,930**	**6,930**	**6,930**	**34,650**

Source: Powercor BMP (revision 9.2)

2.4.1 Further section 109 request regarding our provisionally accepted BMP

ESV's further section 109 request that accompanied the provisional acceptance of our BMP outlined three additional revisions that we are required to make. These revisions include:

- further detail regarding the minimum number of network interventions in each year (e.g. minimum annual interventions and replacements in HBRA, and minimum replacements of already reinforced poles)
- further clarification regarding the scope and currency of documentation incorporated in the BMP
- further clarification regarding the management of safety risks in connection with conductor clearances.

On 4 February 2022, we submitted a response to ESV regarding its further section 109 notice.[7] This response outlined our unqualified commitment to achieving the minimum required pole volumes, and included the additional minimum specifications requested by ESV, as set out in table 2.3. Our submission, however, noted administrative concerns regarding the scope of documentation sought to be incorporated in the BMP.

Table 2.3 Minimum wood pole interventions required under our further revised BMP (additional specifications)

Intervention type	2022	2023	2024	2025	2026	Total
Network-wide: interventions	6,930	6,930	6,930	6,930	6,930	34,650
HBRA and BCAs: interventions	5,100	5,100	5,100	5,100	5,100	25,500
HBRA and BCAs: replacements	2,800	2,800	2,800	2,800	2,800	14,000
Network-wide: reinforced replacements	720	720	720	720	720	3,600
HBRA and BCAs: reinforced replacements	600	600	600	600	600	3,000

Source: Powercor, *Submission in response to ESV's further section 109 request*, 4 February 2022

ESV responded to our submission on 18 February 2022, with the primary focus on documentation issues.[8] Regarding poles, the total minimum five-year intervention volumes have not changed.

We will now submit a further revised BMP by 19 April 2022, and ESV invited us to apply for an extension to its provisional acceptance of our BMP so that both parties can resolve the issues around documentation. Our further revised BMP will maintain the total minimum five-year intervention volumes, such that there remains sufficient certainty regarding these volumes and we are proceeding with our delivery program as planned.

7 Powercor, *Submission in response to ESV's further section 109 request*, 4 February 2022.

8 ESV, *Decision on Powercor's response in relation to ESV's further section 109 request*, 18 February 2022.

3 Positive change event

The National Electricity Rules (**the Rules**) include cost pass-through provisions that allow us to seek recovery of materially higher costs incurred in providing direct control services than we would have incurred but for a specific event. The eligible pass-through events are defined in the Rules, and include (but are not limited to) a service standard event, and a regulatory change event.[9]

For the reasons outlined in this section, the revisions to and provisional acceptance of our revised BMP meet either of these definitions.

3.1 Service standard event

The Rules define a service standard event as a legislative or administrative act or decision that:[10]

- has the effect of:
  - substantially varying, during the course of a regulatory control period, the manner in which a distributor is required to provide a direct control service; or
  - imposing, removing or varying, during the course of a regulatory control period, minimum service standards applicable to prescribed transmission services or direct control services; or
  - altering, during the course of a regulatory control period, the nature or scope of the prescribed transmission services or direct control services, provided by the service provider; and
- materially increases or materially decreases the costs to the service provider of providing prescribed transmission services or direct control services.

It is sufficient for the relevant act or decision to have any one of the effects set out in the three sub-paragraphs of paragraph (a) to render that act or decision a service standard event. For the purpose of this pass-through application, we focus on sub-paragraphs (a)(i) and (a)(iii).

The requirement of paragraph (b) of the Rules definition is discussed in section 3.3.

3.1.1 Legislative or administrative act or decision

ESV is a body corporate established under the *Energy Safe Victoria Act 2005 (Vic)*. ESV's functions include, relevantly, the functions conferred on it by the Electricity Safety Act, one of which is to regulate, monitor and enforce the prevention and mitigation of bushfires that arise out of incidents involving electric lines. For the purpose of performing its functions, ESV has such powers as are conferred on it by any Act or the Regulations under any Act. These powers include the issuing of directions pursuant to section 109 and the acceptance of a BMP pursuant to section 113A of the Electricity Safety Act.

ESV is thus an administrative body authorised by statute to require amendments to our BMP and to accept our revised BMP. Therefore, the request to submit a revised BMP meeting specified minimum wood pole interventions, and the subsequent provisional acceptance of this BMP, is an administrative act or decision for the purposes of the service standard event definition.

3.1.2 Effect of the act or decision

As our revised BMP includes minimum intervention volumes to be completed during the calendar years 2022–2026, the service standard event occurs during the course of the current regulatory control period.

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9 NER, cl. 6.6.1(a1).

10 NER, chapter 10.

Further, the changes requested to, and subsequently specified in our revised BMP, are concerned with the planning, design, repair, maintenance, construction, and operation of our distribution network (i.e. they relate to the installation of wood poles to support the distribution of electricity). The AER's final decision for our distribution determination classified these as a standard control service.[11]

Substantially varying the manner in which we are required to provide a direct control service

Sub-paragraph (a)(i) of the service standard event definition requires the administrative act or decision to substantially vary the manner in which we will provide a direct control service. Meeting this requirement is evident in the changes required to our wood pole management practices, as well as the procurement of additional resources to implement the minimum volumes.

The changes to our wood pole management practices include those set out in table 3.1. The substantial nature of these changes is evident in both the resultant uplift in wood pole intervention volumes and expenditure.

Table 3.1 Asset management changes required to comply with our revised BMP

Document	Overview	Amendments in our revised BMP
D-390: network asset maintenance policy for inspection of poles	Details the management regime of non-routine maintenance identified following an asset inspection, specifically describing the type of inspection, time-frame and the pole classification criteria in establishing the pole condition	Criteria for 'not suitable to stake' amended to include poles located in HBRA that require double staking (i.e. we will no longer double-stake wood poles in HBRA)
D-398: network asset maintenance policy for management of permanent reinforcement systems on wood poles	Details how permanent reinforcement systems shall be managed to optimise asset performance, including the management of existing double-staked poles in HBRA	Amended to classify all double-staked poles in HBRA as unserviceable where a full inspection using Woodscan cannot be undertaken in accordance with our inspection policies
D-406: network asset maintenance policy for serviceability assessment of poles	Details the serviceability thresholds to be used in the assessment of pole structures in determining compliance driven wood pole conditions, and outlines business rules related to the assessment of pole serviceability as it pertains to the ability to withstand pole tip loads on the structure	No material changes to serviceability assessment
D-407: network asset maintenance policy for risk based asset management of poles	Details the deployed risk-based asset management approach through a condition based risk model (CBRM) to determine prudent pole interventions, achieving a balance between risk, cost and performance	Amended RBAM implementation approach for HBRA (and above) to prioritise interventions based on, for example, minimum age specifications

Source: Powercor

11 AER, *Final decision, Powercor distribution determination 2021–2026*, April 2021, Attachment 13, p. 4.

Altering the nature or scope of direct control services

Sub-paragraph (a)(iii) requires the administrative act or decision to have the effect of altering the nature or scope of our direct control services more generally. This includes an alteration in the extent or range of those services (whereby a change in amount or volume represents a change in extent).[12]

This is consistent with previous AER decisions on other pass-through applications. For example, in considering the costs arising from the Victorian Bushfires Royal Commission, the AER previously concluded that the increase in the volume of existing direct control services we were being required to provide represented a change in the scope of services.[13]

It follows, therefore, that the extent of additional interventions required by our revised BMP represents an alteration to the nature or scope of direct control services.

3.2 Regulatory change event

If the AER does not agree that ESV's provisional acceptance of our revised BMP represents a service standard event (as discussed in section 3.1), we consider it would then constitute a regulatory change event.

The Rules define a regulatory change event as a change in a regulatory obligation or requirement that meets each of the following:

- falls within no other category of pass-through event
- occurs during the course of a regulatory control period
- substantially affects the manner in which we provide direct control services
- materially increases or materially decreases the costs of providing those services.

Relevantly, the definition of a 'regulatory obligation or requirement' is defined pursuant to section 2D of the National Electricity Law (**the Law**) to include any of the following:

- a distribution system safety duty or transmission system safety duty
- an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act, that regulates the use of land in a participating jurisdiction by a regulated network service provider
- an Act of a participating jurisdiction or any instrument made or issued under or for the purposes of that Act that relates to the protection of the environment
- an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act… that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination.

Our obligation to comply with a BMP accepted by ESV under section 113B of the Act (provisionally or otherwise), being an Act of a participating jurisdiction, is a 'distribution system safety duty'. Accordingly, ESV's provisional

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12 The term 'scope', where it appears in sub-paragraph (a)(iii), takes its ordinary and natural meaning, being 'extent or range of view, outlook, operation, effectiveness, etc' (Macquarie Online Dictionary). A dictionary definition of 'scope' uses the word 'extent' as a synonym for 'scope' (see above). The Macquarie Online Dictionary defines 'extent' to mean 'the space or degree to which a thing extends; length, area or volume'.

13 For example, in considering the costs arising from the VBRC, the AER previously determined that a 'change in the volume of a service can constitute a change in the nature or scope of that service, if it changes the very character or extent or range of the services being provided'. See, AER, *Final decision, Powercor Australia cost pass through application of 13 December 2011 for costs arising from the Victorian Bushfire Royal Commission*, 7 March 2012, p. 26.

acceptance of our revised BMP results in a change in the content of our obligation under section 113B of the Act to comply with an ESV accepted BMP.

Alternatively, or in addition, ESV's section 109 notice and ESV's decision to provisionally accept our BMP are instruments issued under or for the purpose of the Electricity Safety Act that materially affect our provision of electricity distribution services. The material effect of these instruments on our provision of our services is explained above.

A regulatory change event also requires the change in obligation to 'substantially affect' the manner in which we provide direct control services. As outlined previously, the substantial impact of the change is evident in the resultant uplift in both wood pole intervention volumes and expenditure.

3.3 Materially increases costs

The Rules definitions of 'positive change event', 'service standard event' and 'regulatory change event' require that the event 'materially' increase the costs of providing direct control services.

Chapter 10 of the Rules defines 'materially', for the purposes of the cost pass-through provisions, as follows:

> *[A]n event results in a Distribution Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Distribution Network Service Provider has incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event, exceeds 1% of the annual revenue requirement for the Distribution Network Service Provider for that regulatory year.*

In previous cost pass-through decisions, the AER has considered the change in costs could relate to the change in total capital costs or it could refer to the change in 'building block' costs. These different interpretations result in different materiality thresholds, with the change in capital expenditure costs resulting in a lower threshold and the alternative interpretation of the return on and of capital expenditure costs resulting in a higher threshold.

However, in its recent cost pass-through decision for AusNet Services, the AER accepted that defining 'costs' as total capital and operating expenditure is the appropriate interpretation.[14] The AER recognised that this interpretation avoids unintended incentive outcomes arising from the interaction between the cost pass-through framework and the operating expenditure and capital expenditure efficiency schemes under the Rules, and avoids creating an inefficient bias towards operating expenditure solutions for distributors responding to potential pass through events.

Consistent with the AER's revised interpretation, the provisional acceptance by ESV of our revised BMP meets the 'materiality' requirement. That is, as shown in table 3.2, it 'materially' increases the costs we will incur in each of the 2022–2026 regulatory years.

Table 3.2 Application of 'materiality' requirement ($ million, 2021)

Description	FY22	FY23	FY24	FY25	FY26
Change in costs	12.4	24.9	25.0	25.2	25.4
Materiality threshold	6.64	6.77	6.90	7.03	7.16

Source: Powercor cost model, MOD.01 [commercial-in-confidence]

[14] AER, *Determination, 500kV transmission line tower collapse cost pass-through, AusNet Services*, September 2020, p. 9.

4 Eligible and proposed pass-through amounts

This section discusses the costs we are likely to incur as a result of ESV provisionally accepting our revised BMP. These costs inform both the eligible and proposed pass-through amounts, which for the purpose of our pass-through application, have been estimated to be equivalent.[15]

4.1 Eligible pass-through amount

The Rules define the eligible pass-through amount as the increase in costs in the provision of direct control services that, as a result of the positive change event, we have or are likely to incur until the end of the regulatory period in which the positive change event occurred.

Our forecast of the eligible pass-through amount has been determined as the sum of the following:

- the product of the incremental intervention volumes set out in our revised BMP and a bottom-up forecast of corresponding unit rates
- negative offset to remove any overlap with funding for pole-top structures already provided through the AER's final determination
- incremental project management and construction delivery management costs
- incremental costs associated with additional planned outages
- incremental overheads, consistent with the approach to variable overheads set out in the AER's final determination.

We discuss the components of our forecast below.

For the avoidance of doubt, we have not sought to estimate the incremental costs already incurred in managing our response to ESV's section 109 notices, the development of our poles pass-through application, or in undertaking the market tender required to procure sufficient labour resources.

4.1.1 Forecast volumes

Table 4.1 sets out the prescribed intervention volume and intervention type for each calendar year from 2022–2026, as specified in our revised BMP.[16] As our revised BMP has been provisionally accepted by ESV, we must deliver these volumes in accordance with section 113B(2) of the Electricity Safety Act.

Table 4.1 Forecast intervention volumes: total

Prescribed intervention	2022	2023	2024	2025	2026	Total
Replacements	4,153	4,155	4,153	4,153	4,153	20,767
Reinforcements	2,777	2,775	2,777	2,777	2,777	13,883
Total	**6,930**	**6,930**	**6,930**	**6,930**	**6,930**	**34,650**

Source: Powercor BMP (revision 9.2)

For the purpose of our pass-through application, we have converted these volumes into financial year forecasts by averaging the two adjacent years. Incremental intervention volumes have then been determined with

15 See, for example, the amounts set out in section 4.2.

16 Our revised BMP recognises that some year-on-year variability may occur in the practical implementation of the program, but that over the full five-year period, the total intervention volumes (including intervention type split) must be met.

reference to the AER's final decision (excluding the first six months of the regulatory period, which are not subject to ESV's section 109 request), as shown in table 4.2 and table 4.3.

Table 4.2 Forecast intervention volumes: incremental replacements

Pole replacements	FY22 (H2)	FY23	FY24	FY25	FY26	Total
AER final decision	1,320	2,639	2,639	2,639	2,639	11,877
Revised BMP	2,077	4,153	4,153	4,153	4,153	18,690
Incremental replacements	**757**	**1,514**	**1,514**	**1,514**	**1,514**	**6,813**

Source: Powercor cost model, MOD.01 [commercial-in-confidence]
Notes: AER final decision volumes have been allocated evenly throughout the period.

Table 4.3 Forecast intervention volumes: incremental reinforcements

Pole reinforcements	FY22 (H2)	FY23	FY24	FY25	FY26	Total
AER final decision	916	1,833	1,833	1,833	1,833	8,248
Revised BMP	1,389	2,776	2,776	2,777	2,777	12,495
Incremental reinforcements	**473**	**943**	**943**	**944**	**944**	**4,247**

Source: Powercor cost model, MOD.01 [commercial-in-confidence]
Notes: AER final decision volumes have been allocated evenly throughout the period.

The total forecast volumes specified in our revised BMP, including the split of intervention type, reflect wood pole management policies designed to meet ESV's stated intention of delivering 'sustainable and safe outcomes'. In developing our intervention forecast, we provided ESV our forecast method and asset management documentation. These documents were subject to rigorous review by ESV, including through their Safety Case Evaluation Panel, and their process to provisionally accept our revised BMP.

Our engagement with ESV also ensured we are targeting poles that ESV consider to be highest risk and meet each of the thresholds set out in their section 109 request. In particular, our initial approach included age-based criteria that targeted poles older than 55 years. However, following feedback from ESV, this was lowered to target poles older than 50 years (as 50 years was the basis of ESV's analysis underpinning its section 109 request).

Given ESV initiated the section 109 request that specified minimum intervention volumes to be included in our revised BMP, our engagement with them on the development of our forecast demonstrates the reasonable steps taken to reduce the magnitude of the eligible pass-through amount.[17] Effectively, the level of interventions is targeting the removal of unserviceable wood poles, and a reduction in the average age of our wood pole population (particularly in higher-risk locations).

We also discussed our proposed approach with our Customer Advisory Panel, including how to best communicate the changes to our customers. The outcome of more quickly managing our large population of aged and lower durability wood poles was well supported (i.e. the additional intervention volumes were seen as a positive outcome).

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17 NER, cl. 6.6.1(j).

A summary of our forecast method is included below:

- forecast volumes are derived based on three separate categories:
  - compliance-driven interventions based on measured condition
  - compliance-driven interventions based on observed condition
  - risk-driven interventions[18]
- we first forecast to intervene on any compliance-driven poles (measured and observed condition), as these poles are expected to become unserviceable during the forecast period (i.e. they represent those poles in worst condition)
- we then apply our risk-based asset management approach to forecast the balance of ESV's overall minimum volumes:
  - our risk-based asset management approach considers the risk and attributable consequences associated with distribution pole assets based on asset criticality
  - the determination of asset criticality is set out in our network asset maintenance policy for risk-based asset management of poles, whereby one represents the lowest criticality (typically low bushfire risk areas (**LBRA**)) and five the highest criticality[19]
  - criticality three poles include those in HBRA with low reliability risk, criticality four includes those in HBRA and LBRA that carry high reliability risk (e.g. key structures on radial 66kV lines), and criticality five poles are those in bushfire construction areas (**BCA**)
  - our risk-driven interventions forecast only considers poles of criticality three or higher, and then applies further age, sound-wood and wood durability class criteria to ensure we only target the worst condition and highest risk of these poles
- our intervention type forecasts reflect the historical, observed average of poles assessed as suitable to stake (consistent with our wood pole management practices) and overall, results in a total reinforcement rate of approximately 40% (which is consistent with the total reinforcement rate in the AER's final decision)
  - our wood pole management practices require all poles classified as unserviceable or added-control serviceable, other than those with observable defects (e.g. fungal fruiting) or those already double-staked, to be assessed for their suitability to stake[20]
  - historically, approximately 30% of unserviceable poles (based on measured condition) have been suitable to stake
  - our practice of replacing any unserviceable pole with observable defects is consistent with long-standing industry best-practice
  - since 2021 (when we started collecting data on the suitability to stake of all poles classified as added-control serviceable), approximately 65% of added-control serviceable poles in higher criticalities have been suitable to stake

[18] This approach is consistent with the framework used to develop our wood pole forecast for our revised regulatory proposal.

[19] Powercor, D-*407: network asset maintenance policy for risk based asset management of poles, Issue 1.3*, November 2021

[20] Added-control serviceable poles are poles that have a level of deterioration that requires additional or more frequent monitoring, but otherwise remain serviceable.

– we do not have historical data on the suitability of serviceable (P4) poles for staking, but have assumed the overwhelming majority (95%) of these will be suitable to stake.[21]

4.1.2 Forecast unit rates

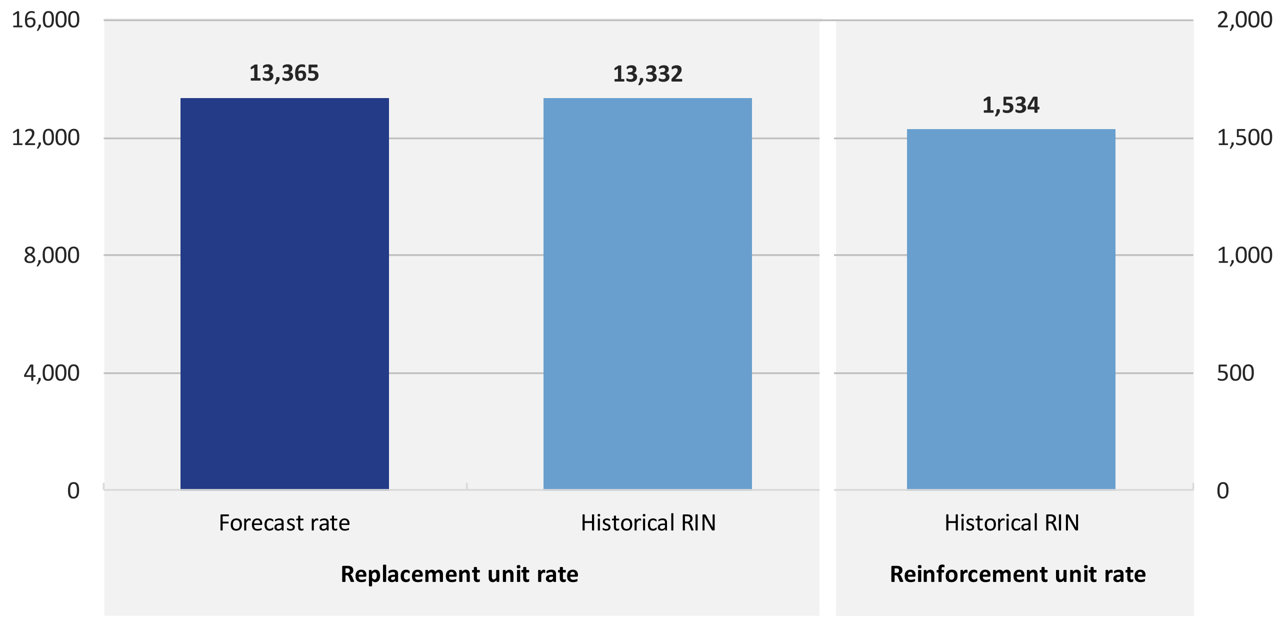
The magnitude of the required increase in minimum wood pole intervention volumes, relative to our existing wood pole volumes, is such that we cannot resource this incremental workload internally.

For example, in 2021 we replaced approximately 2,700 wood poles across our network. From 2022 onwards, we will need to replace a mandated minimum of 4,153 per annum—more than a 50% uplift per annum. This increase represents additional work hours that are beyond our existing, internal labour force capability.

In November 2021, therefore, we undertook a market tender process for the provision of pole replacement labour services. These market-tested labour rates have been combined with materials, pole design works, and earthing costs—each of which will continue to be provided internally—to determine a bottom-up replacement unit rate.

As shown in figure 4.1, our bottom-up replacement unit rate is consistent with the recent four-year average of our historical RIN data. This top-down check validates the reasonableness of our forecast.

Figure 4.1 Top-down unit rate comparisons ($ per pole)



Source: Powercor
Notes: Our forecast reinforcement unit rate is equal to our historical RIN rate as we already outsource these works to third parties.

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21 Factors that limit the suitability of a pole for staking include the following: less than 60mm of sound timber one metre above ground level, defects above the ground level inspection zone which may affect strength of the pole, such as splits, large knots, fungal fruiting bodies and lightning strikes, loose knot holes, bent/bowing pole, visible termite attack above two meters, lightning strikes, fungal fruiting bodies on pole, presence of damp-wood termites (Glyptotermes) or evidence of a past infestation, presence of subterranean termites or evidence of a past infestation in durability class three poles (class one and class two poles infected with subterranean termites may be staked when used in conjunction with an approved termite treatment process), poles located in HV enclosures including zone substations and ground type substations, the presence of a SWER earthing system (poles fitted with other types of earthing systems may be staked, however, HV earths shall be tested after the stakes are installed), poles leaning greater than five degrees in any direction, a pole identified as being struck by a vehicle, pole diameter is below the minimum required for the staking system, pole is located in HBRA and requires double staking.

Pole installation (replacements)

The request for quote for pole installation services required each tenderer to provide unitised rates for separate regions within our network, and for both concrete and wood poles for four different voltage levels (LV, HV, sub-transmission and SWER poles). These pole types reflect the typical poles installed on our network.

We received responses to our tender from four resource partners. The unitised rates from two of these providers were reasonably consistent, while the other two respondents forecasted higher rates (with one provider also only offering rates for a small sub-set of locations).

For the purpose of our pass-through application, we developed a blended unit rate as follows:

- the two lowest cost tender respondents were given equal weight, and we ignored the higher cost providers
- our volume forecast includes the location and type of pole, and these characteristics were used to determine a single blended rate weighted by depot, voltage type and material.

For the following reasons, we consider our unit rate forecast for the installation component of wood pole replacements is prudent and efficient, and will closely reflect the installation costs we will actually incur in delivering our wood pole replacement program:

- we do not have the internal resources to undertake the uplift in required minimum pole replacements, and will therefore need to rely on external providers
- our forecast rates were determined using a competitive tender process, undertaken on an arms-length basis
- our procurement process included a 'best and final offer' process, which led to further reductions in the unit rates originally provided by the tender respondents
- we excluded the two higher cost providers as they may not reflect efficient rates
- relying on multiple resource partners to manage delivery and availability risks is prudent operational practice, and no single provider has indicated they can supply the full program
- the voltage-type split reflected in our blended rate is consistent with our historical RIN data (i.e. our forecast results in a ratio of HV, LV and sub-transmission poles that is consistent with historical RIN averages)
- the material-type split reflected in our blended rate is based on the forecast location of the existing pole, and results in a split between wood and concrete replacements that is consistent with history (i.e. our forecast results in approximately 65% of replaced poles being concrete, and this is consistent with our observed history).

Materials costs

The materials cost component of our blended wood pole replacement unit rate was determined using the total materials cost for wood pole replacements recorded in our SAP system from 2018–2021, divided by the corresponding number of wood pole replacements. This approach, therefore, implicitly captures the materials cost of the pole and pole-top structures (if replaced with the pole), and associated storage costs.

For the reasons below, our forecast approach is prudent and efficient, and will closely reflect the materials costs we will actually incur in delivering our wood pole replacement program:

- our forecast volumes reflect a split of pole material and voltage types that are consistent with our historical data, such that on a per-pole basis, historical materials requirements will reasonably reflect future needs
- it is efficient (and common, long-standing industry practice) to replace many pole-top structures at the same time the corresponding pole is being replaced (rather than remove and re-attach), and consistent with our

resource partner agreements, we will continue to procure and 'free-issue' any major hardware for installation

- as discussed in section 4.1.3, we have forecast a negative offset in our pass-through application to reflect any expected overlap associated with pole-top structures that were already funded through the AER's final determination (and that instead, will now be replaced with the incremental pole volumes)
- we have applied zero real material cost escalation (consistent with the AER's final decision), notwithstanding that recent experience indicates pole material costs will continue to increase at rates above inflation.

Earthing costs

Any concrete pole installed on our network must be earthed to ensure the ongoing safety of our communities and employees. We use civil contractors for these works, and as such, it is not covered by the labour component of our resource partner contracts.

The type of earthing systems used (e.g. deep driven, multiple or coiled) will depend on a range of factors, including the underlying characteristics of the type of soil where the earth is to be installed. As we are unable to predict these soil conditions in advance, we forecast earthing costs based on previous works—similar to our materials cost forecast, this implicitly assumes the forecast mix of earthing works and types will be consistent with historical earthing jobs.

Specifically, we reviewed historical civil works orders recorded in our system, and selected jobs where earthing works were the only component of the scope undertaken (so that additional civil works, such as reinstatement activities are not inflating costs). We then assessed the cost range of these completed earthing works, and considered both the mean and median costs—these are shown in table 4.4.

Table 4.4 Earthing costs ($, 2021)

Description	Cost
Historical maximum	17,826
Historical mean	2,257
Historical median	1,760

Source: Powercor

We have relied on the median earthing costs for the purpose of our cost pass-through application. This approach minimises the impact of any outliers in our data sample (e.g. two projects incurred earthing costs above $10,000), and in combination with our other replacement rate components, results in an total unit rate that is consistent with our historical RIN data.[22]

Design costs

Each pole on our network is subject to our engineering design process prior to replacement.

Engineering design is required to ensure new poles are installed to comply with current standards. This includes minimum height requirements to meet modern clearance standards (noting that design standards over 50 years ago resulted in shorter poles than required today). The design review also takes account of any assets connected

22 We also considered removing outliers from our analysis, but this still resulted in an historical mean that exceeded the median.

to the pole to ensure the design will withstand expected bending forces, as well as site-specific characteristics (e.g. geographical or topographical factors).

Where detailed engineering design is required, the design process includes the development and documentation of a scope of works. This can be an iterative process based on site visits and reports from field teams.

Consistent with our existing processes and resource partner agreements, engineering design will continue to be provided by internal labour. Accordingly, our forecast for engineering design had regard to both our actual design costs and engineering experience—for example:

- we first considered feedback from experienced design engineers on the typical time taken for most pole design projects. This feedback indicated the end-to-end design process for a wood pole replacement typically requires between three and four hours per pole
- the range of design hours was then compared to the cost of a typical pole replacement. Relative to our recent RIN data, this range equates to around three per cent of the total replacement cost (which was not considered unreasonable)
- for the purpose of our pass-through application, we have limited our engineering design forecast to the lower end of the typical range (i.e. three hours per pole). This recognises that scale efficiencies may be achievable, but that these are limited by the fact that each pole differs with respect to the underlying network and geographic characteristics.

Pole reinforcement costs

We have historically outsourced our wood pole reinforcement works to external third parties, and these providers have indicated they can scale to meet our increased volume requirements. Accordingly, our forecast unit rate for pole staking is based on historical RIN data from 2017–2020 (i.e. our most recently available, audited RIN data).

4.1.3 Pole-top structure offset

As noted previously, it is long-standing industry practice to replace some pole-top structures at the same time the corresponding pole is being replaced. This is because is it typically more efficient to 'stand-up' a new pole with assets already installed than to remove, inspect, refurbish and re-attach existing assets.

The above means that by replacing an incrementally greater volume of poles, we will also be replacing an incrementally greater number of pole-top structures. These pole-top structures were forecast separately in the AER's final determination, resulting in an overlap in our pass-through application that we have sought to remove.

We have determined this overlap using historical RIN data, as outlined below:

- we first identified the number of pole-top structures inspected based on the number of pole inspections, and the ratio of pole-top structures to poles (i.e. whenever a pole is inspected we also inspect any pole-top structures installed, and across our network we have approximately 1.14 pole-top structures per pole)
- a pole-top structure replacement 'find' rate was then determined based on the volume of pole-top structures replaced (where the corresponding pole was not replaced) relative to the total volume of pole-top structure inspections
- the pole-top structure replacement find rate was then applied to the incremental volume of pole replacements, and multiplied by the average pole-top structure unit rate.

The application of our pole-top structure offset is shown in our attached cost model.[23]

4.1.4 Program management office and construction delivery

Our pole asset management practices have historically been delivered through our existing business structure, as part of our broader lines maintenance program. However, the scale of the minimum wood pole interventions now required under ESV's section 109 request, the risk of enforcement penalties for non-delivery, and the manner in which they will be delivered (e.g. using external partners), necessitated the establishment of a new dedicated pole intervention program and governance structure.

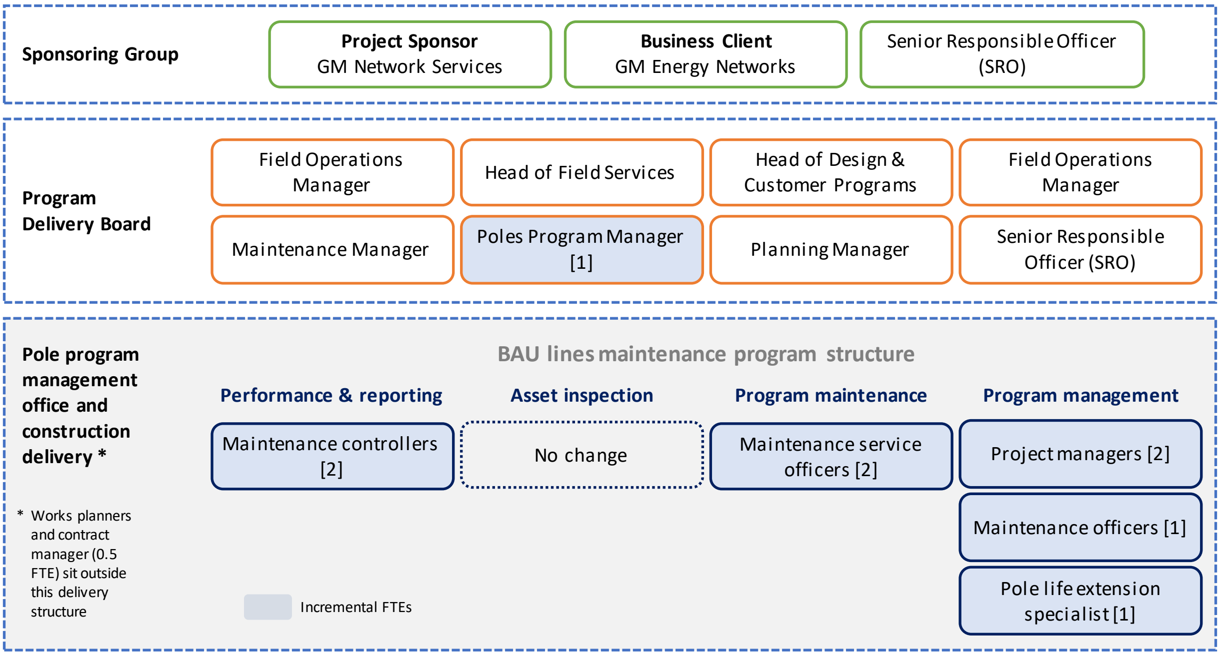
The establishment of a dedicated delivery team is consistent with widely accepted program delivery principles, and our approach to other major projects. For example, we most recently established dedicated delivery teams for the following major works programs:

- CBD security of supply and Waratah Place zone substation reconstruction
- REFCL program
- West Gate Tunnel project and West Melbourne terminal station offload.

The common features of each of these projects is the scale, complexity and delivery risk of the underlying works.

The governance structure of our new dedicated pole intervention program is outlined in figure 4.2. This includes a new dedicated poles program manager reporting directly to the Program Delivery Board. The delivery of the program will sit within the existing delivery structure of our business-as-usual lines maintenance program, with new roles primarily limited to those driven by the scale of incremental pole intervention works.

Figure 4.2 Pole management program: delivery structure



Source: Powercor

[23] Powercor cost model, MOD.01 [commercial-in-confidence]

Further descriptions of the responsibilities of the roles identified above (and within our attached cost model) are provided in table 4.5 and table 4.6.[24]

Table 4.5 Program management

Role	Responsibilities
Program manager (new position)	• Responsible for overarching delivery of poles program • Oversee resource use and program delivery, and reports directly to the Poles Program Delivery Board
Maintenance controllers	• Monitor program controls to support program management, including tracking the varying elements of the program, such as costs, schedules and quality plans • Develop progress reports, schedule updates, and maintains budget, risk and issues registers
Contract manager (new position, part-time)	• Manage contractor performance • Manage contractor on-boarding and system access requirements

Source: Powercor

Table 4.6 Construction delivery management

Role	Responsibilities
Works planner (part-time)	• Determine allocation of job orders to internal or external labour to ensure efficient resource utilisation and ensure any minimum contract allocation requirements are met
Maintenance service officers	• Determine intervention action (or non-action) from inspection notifications • Ensure required materials are available on site, based on a review of design scopes • Estimate time required for works, and create packages of work orders for issuance by maintenance officers
Maintenance officers	• Create field plans and issue work packages to construction delivery teams • Maintain SAP records and close-out of work orders
Project managers	• Ensure individual packages of poles are delivered in accordance with policy requirements
Pole life extension specialist (new position)	• Responsible for end-to-end pole reinforcement process

Source: Powercor

In total, our program management and construction delivery management costs are around three and four per cent (respectively) of our total incremental forecast. This is consistent with broader expectations regarding program management and construction delivery, whereby these costs typically account for between 5–10% of the total value of large capital projects or programs.

24 Powercor cost model, MOD.01 [commercial-in-confidence]

4.1.5 Additional resources

The additional resources component of our pass-through application reflects the costs associated with the incremental volume of planned outages required to deliver the incremental volume of wood pole replacements. These costs are incurred through increased customer notification requirements, and increased network control room switching requirements.

As discussed in section 4.1.6, the increase in planned outages also has implications for our customer service incentive scheme.

Planned outages

Where safe, and we are practically able to do so, we endeavour to complete works on our network under 'live' conditions. This means the need to complete pole intervention works under outage conditions is typically driven by the voltage and structure type of the pole, and the complexity and risks associated with the scope of works and pole location.

Accordingly, our approach to forecasting planned outages is based on the proportion of specific voltage and structure types expected to be intervened on over the 2021–2026 regulatory period (as per the approach outlined in section 4.1.1). Specifically:

- all pole reinforcement works will be completed under live conditions, and will not require an outage
- HV intermediate structure types (which represent the largest single subset of poles on our network) will be replaced under live conditions, and will not require an outage
- sub-transmission pole replacements will not require planned outages due to the ability to reconfigure our network.

The above approach results in approximately 64% of our pole interventions forecast to be completed without a planned outage. The application of this to our incremental pole volumes is summarised in table 4.7.

Table 4.7 Incremental planned outages: 2021–2026 regulatory period

Description	Volume
Total incremental interventions	11,060
Incremental interventions forecast to be completed live (e.g. reinforcements, HV intermediate, sub-transmission)	7,039
Incremental planned outages	4,021

Source: Powercor

Customer notifications

We are required to provide notification to all customers expected to be impacted by a planned outage. Notifications are typically provided as a written letter distributed via Australia Post and an SMS.[25]

We have forecast the costs associated with notifying customers of the incremental planned outages based on the following:

- incremental planned outages (as per table 4.7)

25 Our customers have the option of selecting their preferred communication channel online (e.g. they can opt-in to digital communication only), but to date, less than 1 per cent of our customers have exercised this option.

- number of customers typically notified per planned outage (67), based on the historical average of customers notified for pole replacement works
- customer notification costs of $1.56 per letter, based on actual mail-out costs.

Network switching costs

All pole replacement works undertaken on our network require the development and implementation of network switching instructions or live-work controls by our network control room staff. These protocols are fundamental to ensuring the safety of our communities, employees and external contractors.

We have forecast the costs associated with the incremental network switching requirements as one full-time equivalent in the network control room.

4.1.6 Customer service incentive scheme

As part of the AER's recent final determination, a customer service incentive scheme (**CSIS**) was introduced for the 2021–2026 regulatory control period. The development of the CSIS was underpinned by genuine customer engagement and reflects an understanding of our customers interests.

The CSIS includes three separate components, with one component being to reduce the average duration and frequency of planned outages compared with our historical average performance.[26]

The revenue at risk for the planned outage component of the CSIS is capped at ±0.15 per cent of annual smoothed revenue, which corresponds to a capped penalty or reward of approximately ±$1 million per annum.

The magnitude of the modelled impact on the CSIS of the incremental planned outages required to meet ESV's specified minimum intervention volumes is such that we will now incur the maximum penalty cap in each of the last four years of the 2021–2026 regulatory control period. Further, the magnitude of the impact is so significant that no reasonable level of investment would allow us to achieve any outcome that other than the maximum penalty—that is, our actual planned outage performance will fall so far below that penalty cap that we will no longer have a strong commercial incentive to minimise the level or extent of planned outages for our customers.

Given the overwhelming support for the CSIS from our customers and key stakeholders, we considered a range of options to ensure the scheme continues to function as envisaged in its original design. These options were also assessed against their ability to ensure we are provided a reasonable opportunity to recover the efficient costs associated with the positive change event (i.e. the mandated minimum required intervention volumes).

The options considered are summarised in figure 4.3, and we will discuss these options at our next scheduled Customer Advisory Panel meeting (March 2022).

[26] The other two components relate to notifications for unplanned outages and telephone answering performance.

Figure 4.3 CSIS options

Exemption for incremental pole replacements	• Administratively complex to define in advance which planned outages are due to the 'incremental' pole intervention volumes • Provides a reasonable opportunity to recover efficient costs	
Direct compensation for adverse revenue impact	• Distorts incentives to minimise planned outages, as compensation would need to be determined in advance and independent of actual performance • Direct compensation for adverse revenue impacts will increase the value of our proposed pass-through application	
Amend targets to reflect forecast increase	• Maintains incentive to minimise planned outages relative to a revised target • Provides a reasonable opportunity to recover efficient costs	**Proposed option**
Propose investments to maintain historical performance	• Maintains incentive to minimise planned outages • Provides a reasonable opportunity to recover efficient costs in principle, but investment options to reduce planned outages are limited and/or the level of investment required is expected to be significant resulting in materially higher costs to customers	
Cease the application of the planned outage component	• Removes any incentive to minimise planned outages, which is counter to customers strong support for including these in the original scheme design • Provides a reasonable opportunity to recover efficient costs	

Source: Powercor

Based on the options above, we consider the most pragmatic approach to maintaining our incentive to minimise planned outages is to amend our CSIS targets as set out in our attached CSIS model.[27] Our proposed amended targets are also shown in table 4.8.

Table 4.8 Amended CSIS targets: planned outages

Planned outages	AER final determination	Proposed targets
SAIDI	65.98	66.25
SAIFI	0.32	0.37

Source: Powercor CSIS target model, MOD.02

4.2 Proposed positive pass-through amount in each regulatory year

The Rules require a pass-through application include the amount of the proposed positive pass-through amount that should be passed through to customers in each regulatory year. Consistent with our attached cost model, and the reasons set out previously in section 4.1, we propose the positive pass-through amounts outlined in table 4.9.[28]

27 Powercor CSIS target model, MOD.02.

28 Powercor cost model, MOD.01 [commercial-in-confidence], and Powercor amended PTRM, MOD.03.

Table 4.9 Proposed positive pass-through amount ($ million, 2021)

Intervention	FY22	FY23	FY24	FY25	FY26	Total
Proposed positive pass-through amount	12.4	24.9	25.0	25.2	25.4	112.8

Source: Powercor

A Confidentiality template

Table A.1 Confidentiality template

Title, page and paragraph number of document containing the confidential information	Description of the confidential information	Topic the confidential information relates to	Identify the recognised confidentiality category that the confidential information falls within	Provide a brief explanation of why the confidential information falls into the selected category	Specify reasons supporting how and why detriment would be caused from disclosing the confidential information	Provide any reasons supporting why the identified detriment is not outweighed by the public benefit
Powercor cost model, MOD.01	Unit rates from market providers	Capital expenditure	Market sensitive cost inputs	Unit rates proposed by market providers were supplied on contractual basis of remaining confidential	Disclosing rates would breach obligations agreed to during contract negotiations	Maintaining confidentiality for market sensitive rates ensures competitive rates can be obtained

Table A.2 Proportion of confidential information

Submission title	Number of pages of submission that include information subject to a claim of confidentiality	Number of pages of submission that do not include information subject to a claim of confidentiality	Total number of pages of submission	Percentage of pages of submission that include information subject to a claim of confidentiality	Percentage of pages of submission that do not include information subject to a claim of confidentiality
Increase to minimum wood pole interventions	1 model	25 pages, and 2 models	25 pages (excluding attachments)	0%	100%

B Compliance checklist

Table B.1 National Electricity Rules compliance checklist

Clause	Requirement	Section
6.6.1(c)	To seek the approval of the AER to pass through a positive pass-through amount, a Distribution Network Service Provider must submit to the AER, within 90 business days of the relevant positive change event occurring, a written statement which specifies: (1) the details of the positive change event	2 and 3
	(2) the date on which the positive change event occurred	2.4
	(3) the eligible pass-through amount in respect of that positive change event	4.1 and 4.2
	(4) the positive pass-through amount the Distribution Network Service Provider proposes in relation to the positive change event	4.2
	(5) the amount of the positive pass-through amount that the Distribution Network Service Provider proposes should be passed through to Distribution Network Users in the regulatory year in which, and each regulatory year after that in which, the positive change event occurred	4.2
	(6) evidence of the actual and likely increase in costs referred to in subparagraph (3); and that such costs occur solely as a consequence of the positive change event	4.1 and MOD.01
	(7) such other information as may be required under any relevant regulatory information instrument.	MOD.02 and MOD.03, and attachments