Regulatory Impact Statement

Electricity Safety Amendment (Bushfire Mitigation) Regulations 2011

How to make a submission in response to this Regulatory Impact Statement

All comments must be in writing and sent to:

Andrew Padanyi
Legal Officer
Energy Safe Victoria
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or sent by email to: apadanyi@esv.vic.gov.au

Comments must be received no later than 5pm on Thursday 4 August 2011. Late submission of comments will not be considered.

Prepared for Energy Safe Victoria by Jaguar Consulting Pty Ltd

Victorian
Competition & Efficiency
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9 May 2011

Mr Andrew Padanyi
Legal Officer
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Dear Mr Padanyi

ASSESSMENT OF REGULATORY IMPACT STATEMENT

Thank you for seeking an assessment of the Regulatory Impact Statement (RIS) on the proposed *Electricity Safety (Bushfire Mitigation) Amendment Regulations* 2011.

The Victorian Competition and Efficiency Commission (VCEC) assesses the adequacy of RISs as required under section 11 of the *Subordinate Legislation Act 1994* (the Act). I advise that the final version of the RIS received by the VCEC on 9 May 2011 meets the requirements of section 10 of the Act.

The VCEC's assessment is based on the adequacy of the evidence presented in the RIS and is focused on the quality of the analysis rather than the merits of the proposal itself. **Therefore, an assessment of adequacy by the VCEC does not represent an endorsement of the proposal.**

In the interests of transparency, most departments and agencies publish this assessment letter alongside the RIS when it is released for consultation. The VCEC recommends that you do the same.

If you have any questions, please contact RegulationReview@vcec.vic.gov.au.

Yours sincerely

Sam Abusah

Assistant Director

Victorian Competition and Efficiency Commission

Summary

Above-ground electricity lines are a significant contributor to bushfire risk. While only a relatively small proportion of bushfires are ignited by electricity asset failure, these ignitions tend to occur when fire conditions are worst, so that fires ignited by electricity assets are responsible for a substantial proportion of the overall damage caused by bushfire. Around half of the fires occurring during each of the last four major fire events in Victoria - those of 1969, 1977, 1983 and 2009 - were ignited by electricity asset failures.

Recognising this, the *Electricity Safety Act 1998* (the Act) requires operators of at-risk electricity assets to prepare Bushfire Management Plans (BMP) and have these plans approved by Energy Safe Victoria (ESV). The *Electricity Safety (Bushfire Mitigation) Regulations 2003* set out a range of specific requirements in relation to BMP.

The Victorian Bushfires Royal Commission (VBRC) made a number of recommendations aimed at reducing the bushfire risks associated with electricity assets in the short, medium and long-term. Key recommendations to be implemented in the short term were to increase the frequency of inspection of electricity assets to a minimum of three-yearly inspections and to improve the effectiveness of inspections by ensuring that all inspectors are adequately qualified.

The *Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010* came into effect in October 2010 and implemented these recommendations. Due to the perceived urgency of putting these changes into effect, the regulations were made by way of an exemption from the Regulatory Impact Statement (RIS) processes set out in the *Subordinate Legislation Act 1994*. Due to this, the regulations have a lifespan of only 12 months. Therefore, it is proposed to make the *Electricity Safety Amendment (Bushfire Mitigation) Regulations 2011*. These regulations would ensure the requirements for inspections at maximum 37 month intervals and for inspectors to possess approved qualifications that are established in the interim regulations would continue in effect until the sunsetting of the principal regulations in 2013.

The costs of these requirements, together with the associated additional monitoring arrangements, are summarised in tables S1 and S2, below. Table 2 presents two cost scenarios. They differ in that Scenario A assumes that ESV will approve BMP for major electricity distributors which combine aerial and ground-based inspections. Scenario B, by contrast, assumes that ESV will require sufficient ground based inspections to be undertaken to conform to the 37 month minimum inspection cycle requirement of the regulations. ESV has yet to receive any BMP proposals containing aerial inspection requirements and will assess any such proposals on the basis of the specific methodology proposed and its likely effectiveness, while also considering this issue in the context of the overall content of the BMP.

The expected costs total $9.5 - $28.0 million in present value terms over the expected life of the regulations, depending on the scenario considered.

Table 5.2: Total costs - distribution businesses

	Scenario A	**Scenario B**
Inspection costs	$2.0 million	$7.8 million
Qualifications	$0.86 million	$1.64 million
Monitoring & review	$0.3 million	$0.3 million
Other	$0.03 million	$0.03 million
Total	$3.19 million	$9.77 million
Total over the life of the regulations (present value)	**$8.88 million**	**$27.37 million**

Table 5.3: Total costs - specified operators

Item	**Cost**
Shortened inspection cycle	$88,000
Qualifications requirements	$77,600
Monitoring and review	$32,000
Other	$33,200
Total	$230,800
Total over the life of the regulations (present value)	**$646,618**

The total costs of the proposed regulations are estimated at between $3.4 million and $10.0 million per annum, with the majority of these costs being attributable to the requirement for more frequent inspections. These costs will initially be borne by the regulated entities. However, it is likely that most of these costs will be passed on to consumers of electricity through the periodic regulated electricity price resetting arrangements in place.

By contrast, the average annual cost of bushfires ignited by electricity assets has been estimated at $60 million. This implies that the regulations will yield net benefits if they are successful in reducing bushfire damage caused by electricity asset failure by between 5.8% and 16.7% (in the low-cost and high-cost scenarios, respectively).

Given the evidence published in the VBRC report as to the expected effectiveness of improved inspection arrangements, it is considered highly likely that the benefits achieved will exceed these threshold levels and that the proposed regulations will yield net benefits for the Victorian community.

The regulations have been assessed against four feasible alternatives. The first alternative differs from the proposed regulations in following the VBRC recommendations strictly and applying the minimum inspection frequency requirement only to SWER and 22kV feeder lines.

The second and third alternatives would adopting a differentiated set of required inspection frequencies, with younger assets being inspected less frequently and older assets inspected more frequently. The second alternative would see assets older than 20 years inspected at 2.5 yearly intervals and younger assets at 5 yearly intervals. The third alternative would differ from this by adopting 37 month/5 yearly inspection frequencies.

The fourth alternative would implement requirements for inspectors to possess minimum qualifications, but would not set a specific minimum inspection frequency.

As discussed above, it is not possible to compare the proposed regulations and the identified alternatives in fully quantified terms, chiefly because of necessary uncertainty as to both the costs associated with the alternatives and the benefits associated with all three alternatives. Consequently, a Multi-Criteria Analysis has been undertaken. Three criteria have been identified, consistent with the underlying objectives of the proposed regulations. These are:

- The ability of the proposal to reduce bushfire risks arising from electricity asset failure;
- The substantive compliance costs of implementing the proposal; and
- The administrative burdens imposed by the proposal.

Thus, the first of these criteria relates to the benefits attributable to the various alternatives, while the second and third relate to the costs they would impose. Given that there are two cost criteria and one benefit criterion, it is necessary to weight the criteria in order to provide a balanced assessment. This means that the total weight given to the two cost criteria must equal that of the benefit criterion. Substantive compliance costs are, where quantifiable, generally found to be significantly larger than administrative burdens. Hence, the substantive criterion has been weighted significantly more heavily than the administrative costs criterion.

Consistent with the above considerations, the following weights have been assigned to the criteria:

- Ability to reduce bushfire risks: 1.0
- Substantive compliance costs: 0.8
- Administrative burdens: 0.2

Table S1: Multi-criteria analysis of feasible alternatives

	Proposed regulations	**Alternative 1: Limit 3 yr inspection requirement to SWER & 22kV lines**	**Alternative 2: Variable inspection frequencies (2.5 yr/5 yr)**	**Alternative 3: Variable inspection frequencies (37 month/5 yr)**	**Alternative 4: Qualifications regulated only**
Reduction in bushfire risk	+4 x 1 = +4	+4 x 1 = +4	+4.5 x 1 = +4.5	+3.5 x 1 = +3.5	+2 x 1 = +2
Substantive compliance cost	-3 x.8 = -2.4	-3 x.8 = -2.4	-3 x.8 = -2.4	-2.5 x .8 = -2	-1 x .8 = -.8
Administrative burden	+2 x .2 = .4	+2 x .2 = .4	-1 x .2 = -.2	-1 x .2 = -.2	0
Total	**+2.0**	**+2.0**	**+1.9**	**+1.3**	**+1.2**

The fact that all five alternatives receive positive scores indicates that all are preferable to the base case of reverting to the principal regulations in their unamended form.

Table S1 shows that the proposed regulations and the alternative of limiting the scope of the maximum inspection frequency requirement jointly receive the highest score of +2.0. The alternative of adopting variable inspection frequencies based on a 2.5 year/5year cycle receives a score only slightly lower, at +1.0. The remaining two alternatives receive significantly lower scores of +1.3 and +1.2 respectively.

This result, in which three alternatives all receive very similar scores, reflects the fact that despite being formally quite distinct, consultation with regulated parties and observation of past practice has demonstrated that the actual response to these three alternatives would be very similar. Thus, for example, the three alternatives were all rated identically in terms of substantive compliance cost, because it is expected that the inspection arrangements that would be adopted in response to each alternative would be essentially identical.

While the proposed regulations and Alternative 1 receive the same score, it has been noted above that the proposed regulations would yield marginally improved risk reduction outcomes by comparison with alternative 1, but would have marginally higher compliance costs. Given this and the strong public desire to reduce bushfire risk, the proposed regulations are preferred.

The proposed regulations have been assessed as required under the National Competition Policy agreements and have been found to be consistent with those requirements.

Given the above, it is proposed to proceed with the proposed regulations.

Contents

1. Introduction

The Electricity Safety Act 1998 requires Major Electricity Companies and Specified Operators (to prepare Bushfire Mitigation Plans (BMP) which set out the actions that they will take to mitigate the risk of bushfire ignition due to failures in above-ground electricity assets (essentially the network of poles and wires) for which they are responsible, which are located in high bushfire risk areas. The *Electricity Safety (Bushfire Mitigation) Regulations 2003* ("the principal regulations") set out specific requirements in relation to the content of BMP. The BMP is expected to constitute the basis for a systematic program of monitoring and maintenance to be undertaken. Thus, it is an example of "process based" regulation.

The report of the Victorian Bushfires Royal Commission found a number of inadequacies with respect to current inspection and maintenance arrangements for electricity assets in high fire risk areas and made recommendations for improved practice in this area. As part of its response to the VBRC recommendations, the former Victorian Government developed and introduced amending regulations, which took effect from October 2010. These regulations, the *Electricity Safety (Bushfire Management) Amendment Interim Regulations 2010* were made by way of an exemption from the Regulatory Impact Statement requirements of the *Subordinate Legislation Act 1994* and, hence, have only a twelve month lifespan. The interim regulations were made in this way as a result of the need to respond quickly to the recommendations of the Royal Commission and ensure that improved regulations were in place as soon as possible.

The proposed regulations would, if made, replace the interim regulations and ensure that the substantive changes introduced via these regulations remain in place for the lifespan of the principal regulations.[1] The major changes introduced via the interim regulations, which are replicated in the proposed regulations, are:

- a requirement that the BMP include an inspection plan that ensures that all assets in high bushfire risk areas are inspected at intervals of no less than 37 months; and
- a requirement that all inspectors possess the relevant qualification to be approved by Energy Safe Victoria.

[1] The principal regulations will sunset in 2013, as a result of the operation of the Subordinate Legislation Act.

2. Objectives of the proposed regulations

The objective of the proposed regulations is to reduce the risk of failure of electricity assets located in high bushfire risk areas due to inadequate inspection practices. Achieving this objective will reduce the incidence of bushfire ignition and the consequent costs to the community.

The specific objectives being pursued in order to achieve this outcome are:

- To ensure an increase in inspection frequency from current levels, and
- To ensure that the quality of the inspection process is improved.

3. Nature and extent of the problem

3.1. Bushfire ignition and electricity assets

Bushfires have a range of causes. They may occur naturally, usually due to lightning strikes. They may also have a range of man-made causes. Chief among these are loss of control of campfires and agricultural burns, arson and emission of sparks from the use of equipment or machinery. Failure of electricity assets can be considered to fall within the latter category. Electricity assets have historically not been significant contributors to the ignition of bushfires. However, there has been a particular focus on this ignition source following the Black Saturday bushfires in Victoria in 2009. This reflects the fact that the report of the Royal Commission into the Black Saturday fires of 2009 found that five of the eleven major fires occurring on that day were ignited as a result of the failure of electricity assets[2].

The Commission found that:

> *"Although the proportion of fires that are caused by electricity infrastructure is low—possibly about 1.5 per cent of all ignitions in normal circumstances—on days of extreme fire danger the percentage of fires linked to electrical assets rises dramatically. Thus, electricity-caused fires are most likely to occur when the risk of a fire getting out of control and having deadly consequences is greatest."*[3]

That is, while only a relatively small proportion of bushfires have historically been ignited by electricity asset failures, the fact that these ignitions tend to occur when conditions are at their most extreme means that an elevated likelihood of a fire developing into a major fire, leading to large scale losses. This, in turn, means that the contribution of electricity asset failures to *total bushfire costs* is likely to be substantially greater than their contribution to ignitions.

The VBRC found[4] that that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983. Specifically:

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and
- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

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[2] These were the fires —Kilmore East, Beechworth–Mudgegonga, Horsham, Coleraine and Pomborneit–Weerite. Of the remaining fires, four were found likely to have been deliberately lit, one was started accidentally, one was started by lightning and two had unknown origins. See: Victorian Bushfires Royal Commission (2010). Report Vol. 1: The fires and the Fire Related Deaths, p 226.

[3] Ibid, p 12.

[4] See: Victorian Bushfire Commission (2009). ***Final Report***, Vol 2, Chapter 4.

Moreover, 70% of the 173 deaths due to the Black Saturday fires resulted from fires ignited by electricity asset failures.[5] The Commission also cited evidence to the inquiry into the 1977 fires from the then Chairman of the State Electricity Commission (SEC). Referring to the overall picture of electricity assets accounting for only a small proportion of total bushfire ignitions, this evidence stated:

> *" This overall picture is in sharp contrast to what happens on days of extreme conditions, such as January 8th 1969 or February 12th 1977. On such days, the incidence of SEC fires rises dramatically.*
>
> *The alarming aspect of these figures is that they tend to occur in widely separated places at approximately the same time and at the time of day when conditions are such that the rate of spread of fire is likely to be at its peak"*

Moreover, the Commission highlighted the fact that Victoria's electricity infrastructure is ageing and this ageing was a contributory cause of ignition in three of the five fires caused by electricity assets[6]. Failures of electricity assets may be caused by fatigue in one or more components, by incorrect installation of components during maintenance, or by combinations of these factors. For example, in relation to the Kilmore East fire, the Commission found:

> *"The fire started after the conductor between poles 38 and 39 failed and the live conductor came into contact with a cable stay supporting pole 38. This contact caused arcing that ignited vegetation near the base of pole 38. An electrical fault was recorded at 11:45.*
>
> *The conductor failed as a result of fatigue on the conductor strands very close to where a helical termination was fitted to the conductor at pole 39. (A helical termination is a device used in electricity distribution; it is wound helically around the conductor and grips it, keeping tension in the line and holding the line off the ground.) The fatigue of the conductor strands was partly caused by the helical termination being incorrectly seated in a thimble, so that it was jammed between the thimble and a clevis device at pole 39, causing stress to the conductor..."*[7]

In relation to the Horsham fire, the Commission found:

> *'the 7 February fire was started by a conductor that fell when the remaining two coach screws came loose as a result of wind-induced vibration enabling the pole cap to become detached. The failure of the pole cap to secure the conductor on pole 15 might have been avoided had there*

[5] VBRC (2009) *Final Report,* various chapters. 119 fatalities occurred in the Kilmore East fire and 2 fatalities in the Beechworth-Mudgegonga fire, both of which fires were caused by electricity asset failures. Thus, 121 of 173 fatalities were caused by electricity asset failures.

[6] In relation to the two remaining fires caused by electricity assets the primary causes were found to be a tree falling on a power line (Beechworth-Mudgegonga fire) and a clashing of conductors (Pomborneit-Weerite fire). These causes are clearly not related to the age of the electricity assets per se.

[7] Ibid, Vol. 1, p 75.

been a shorter inspection cycle: pole 15 had not been inspected for about four and a half years' (Vol 1., p.99).

In relation to the Coleraine fire:

'The fire started after the tie wire that held the conductor in place on the top of pole 3 broke, allowing the conductor to fall from the pole. The break probably occurred after Powercor, the operator of the line, had last inspected the line, in September 2004, in accordance with its asset inspection policy' (Vol 1, p.111).

The Commission cited research by a major distribution company relating to its own assets, which provides strong support for the view that the ageing of the Victorian electricity infrastructure is likely to increase substantially the risk of bushfire ignition due to asset failure in the absence of significant changes to current practices:

"SP AusNet provided to the Commission the results of a study of its conductor fleet, which noted, among other things, 'The primary issue facing SP AusNet is the increasing age profile and deteriorating performance (2% p.a.) of steel and copper conductor through failure …' SP AusNet's conductors have a regulatory life of 60 years, and its conductor fleet has an average age of 41 to 45 years. Most of its steel and copper conductors are now more than 50 years old; they account for all conductors of above-average age in its fleet. The failure of steel and copper conductors is the primary type of conductor failure attributed to end-of-life characteristics.

The report of SP AusNet's conductor study also noted that the great majority of conductor failures on the organisation's network involved high-voltage conductors and that this represented a 'considerable risk to the business from a public safety and bushfire perspective'. The report said, 'In the absence of planned conductor replacement programs, ***failure rates may begin to increase at an exponential rate due to the increasing proportion of [the] conductor fleet approaching current failure age ranges****'"*[8] [emphasis added].

Similarly**,** the VBRC cited a October 2004 report from Powercor, which showed that 16 per cent of the overhead distribution line assets in the Powercor network are between 35 and 44 years of age, 5 per cent between 45 and 54 years of age, 1 per cent between 55 and 64 years of age and 1 per cent between 65 and 74 years of age.[9]

International reports also indicate a high level of awareness of the issue of ageing electricity infrastructure and the associated expectation of a rapid increase in failure rates. For example:

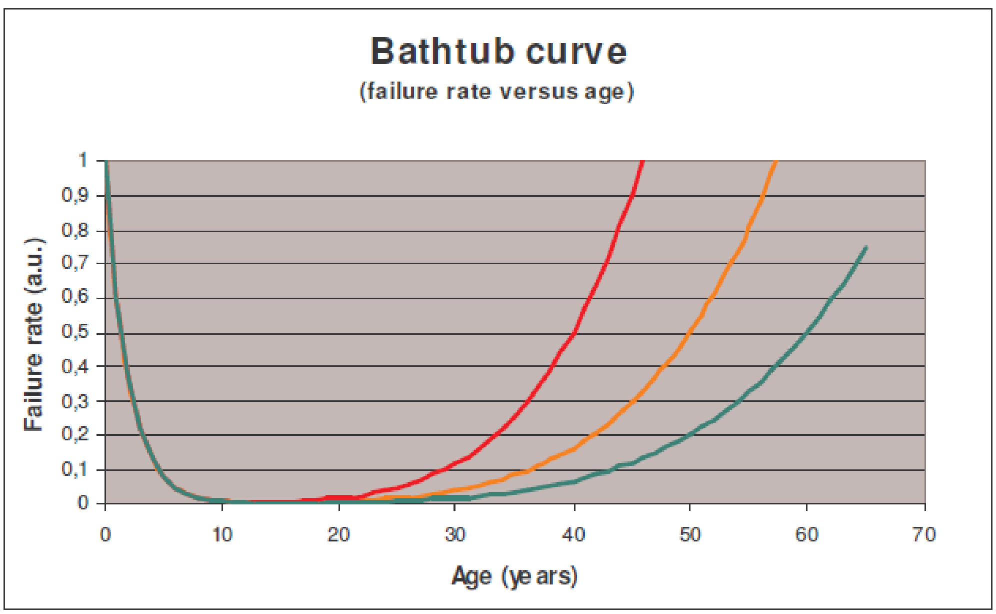
[8] See: Victorian Bushfire Commission (2009). ***Final Report***, Vol 2, Chapter 4.
[9] Exhibit 578 – SKM Powercor and Citipower Age Opex Report – ***Impact of Ageing Assets on Operating Expenses***. Cited in Victorian Bushfire Commission (2009). ***Final Report***, Vol 2, p 151.

"The components of electricity networks are ageing. It is expected that within a horizon of 15 years, the performance will deteriorate significantly, while the costs for operating the networks will increase enormously...

Typically, after a certain period of operation, asset performance will deteriorate and the failure expectation will increase. However, the exact condition of most assets is unknown, and thus what their expected failure rates and remaining lifetimes are is also unknown. ***Extensive condition assessments have to be made in order to fill this knowledge gap****."*[10] [Emphasis added]**.**

The same source includes the following "bathtub curve" as a general representation of the relationship between asset age and failure rates within the electricity industry, with the different curves representing the impact of different maintenance regimes. This graph suggests that, even given a high quality maintenance regime, assets as old as those which form the main part of Victoria's electricity infrastructure are entering the period of rapidly increasing failure rates.

Graph 3.1: Relationship between age of electricity assets and expected failure rate



Source: Leonardo Energy (2007).

The Commission argued that, "*as components of the distribution network age and approach the end of their engineering life, there will probably be an increase in the number of fires resulting from asset failures unless urgent preventive steps are taken*". It therefore made a number of recommendations for

[10] Leonardo Energy (2007). ***Electricity Briefing Paper***, p 1, p 4. Jongepier, AG. See: http://www.leonardo-energy.org/webfm_send/160

medium to long-term action to reduce the risk of electricity assets causing future bushfires. These recommendations were:

- The progressive replacement of Single Wire Earth Return (SWER) and 22 kilovolt (kV) distribution feeders with other technologies (including aerial bundled cabling and underground cable) that provides substantially reduced bushfire risk (recommendation 27);
- To require distribution businesses to take steps to reduce the risk posed by hazardous trees - i.e. those that may come into contact with electricity assets in foreseeable circumstances but are outside the clearance zone (recommendation 30); and
- That ESV require the fitment of spreaders to all lines with a history of clashing or a potential to do so and require the fitment of vibration dampers to all spans of over 300 metres between poles (recommendation 33);

The Commission also recommended that ESV's mandate to act to minimise the risks of bushfire ignition due to the failure of electricity assets be strengthened (recommendation 34).

At the same time, it was recognised that the necessarily long time-horizon over which many of these recommendations would need to be implemented meant that the identified risks of ignition due to electricity assets would remain significant for a number of years to come.

Inspection regimes and bushfire risk due to electricity asset failure

Given the long-term implementation task for the above recommendations, the Commission also identified the need for action to be taken in the short term to reduce risk. These shorter-term recommendations focused on the inspection regimes that are fundamental to ensuring that specific electricity assets that have degraded and are at risk of failure are identified and replaced.

This focus reflected expert evidence to the Commission which indicated that the parameters of the inspection regimes adopted have very substantial impacts on the likelihood of bushfire ignition due to electricity asset failure. Hence, the effectiveness of the inspection regime is a crucial determinant in practice of the level of bushfire risk posed by electricity assets, while this dynamic is especially important in the context of an ageing asset base, due to the rapid increase in the probability of failure that occurs as assets near the end of their service life.

As noted above, a range of evidence demonstrates that electricity assets can be expected to demonstrate rapidly increasing failure rates as they near the end of their service life, while much of the current asset base is approaching this point in its lifecycle. This likelihood of rapidly increasing failure rates clearly increases the importance of a timely and effective asset inspection regime as a major element in controlling the risk of bushfire ignition due to asset failures.

These observations alone would provide a significant body of evidence to suggest that asset inspection programs should be expanded and improved in the current context of rapidly ageing electricity infrastructure. However, the extent of the contribution of asset inspection issues to the broad problem of bushfire ignition risk due to asset failures is potentially increased further. This is due to a regime of asset inspection frequency which in many cases been significantly reduced from previous levels over the past 10 - 15 years.

The Commission heard that the former SEC had introduced a three-year inspection cycle following the 1977 bushfires. However, this cycle was progressively extended in the following years: in around the mid 1990s a five year cycle was adopted for assets not deemed a fire hazard, while the current practice of a five- year inspection cycle for timber poles and a ten-year cycle for concrete poles, including those in high bushfire risk areas, was adopted by the major distribution companies in the early 2000s.

Evidence was also presented to the Commission which specifically addressed the question of the relative effectiveness of different asset inspection frequencies in preventing the in-service asset failures that give rise to bushfire ignition risk. The Commission cited a 1997 study of the Powercor network which found that a reduction in the inspection interval from five years to three years would be expected to result in a 70 per cent reduction in in-service failures. The same study found that:

> *"...a substantial improvement in the effectiveness of asset inspection significantly reduces the risk of in-service asset failure. Powercor's analysis shows that, if the improvements in effectiveness foreshadowed in 1997 had been made without extending the inspection cycle, the projected number of in-service failures each year would have reduced from 500 to 84."*[11]

Thus, a study commissioned by a major electricity company concludes that both the length of the asset inspection cycle and the effectiveness of the inspections undertaken are critical determinants in practice of the extent of the risk of bushfire ignition due to electricity asset failures. The context is one in which the regulations did not, until the passage of the Interim regulations in 2010, contain any specific requirements in relation to the training of inspectors. In the case of major electricity distribution companies, inspection services have frequently been supplied under contract by external service providers. The distribution companies have required inspectors operating under these contracts to have successfully completed a training course which is based on that previously developed by the SEC.

However, evidence presented to the Commission has highlighted faults with current training arrangements, as well as those relating to the auditing of the performance of inspectors. In general terms it was found that, whereas asset inspections had previously been undertaken by linesmen, who had undertaken substantial training in a wide range of problems found throughout the system in the context of an extended apprenticeship, inspection activity was now largely undertaken by inspectors with very limited and specific training. In the case of one third party provider of inspection services, the

[11] Victorian Bushfire Royal Commission (2010). ***Final Report***. Vol. 2, Ch 4., p 160.

initial training provided consisted of three days of classroom training, a competency test and a period of supervised field work.

Moreover, evidence was presented that inspectors had, in many cases, received training provided by organisations not accredited as Registered Training Organisations under the Australian Vocational Education and Training (VET) framework, despite this being a contractual requirement of major electricity companies.[12]

Reviewing this evidence, the Commission argued:

> *"Improving the efficacy of inspection regimes is crucial to mitigating the bushfire risk created by the failure of electricity assets. Whether network components are repaired or replaced before they fail or are at risk of failing is determined in almost all cases on the basis of inspection results, and there is heavy reliance on cyclical inspections[13]"*

The Commission found that:

> *"... both expert opinion and the network operators' analyses support a finding that shortening the inspection cycle would appreciably reduce the risk of assets failing in service and consequentially reduce the risk of bushfires starting as a result of failed assets".[14]*

Consistent with this view, it recommended that both the frequency and the effectiveness of asset inspections should be significantly improved. Specifically, it recommended:

The State (through Energy Safe Victoria) require distribution businesses to change their asset inspection standards and procedures to require that all SWER lines and all 22-kilovolt feeders in areas of high bushfire risk are inspected at least every three years. (Recommendation 28)

and

The State (through Energy Safe Victoria) require distribution businesses to review and modify their current practices, standards and procedures for the training and auditing of asset inspectors to ensure that registered training organisations provide adequate theoretical and practical training for asset inspectors. (Recommendation 29).

The proposed regulations would implement both of these recommendations. It should be noted that the interim and proposed regulations go slightly beyond recommendation 28, in that they apply a maximum 37 month inspection cycle to all high risk powerlines, defined as high voltage, above-ground

[12] VBRC (2010), op. cit, pp 162 - 165.
[13] ibid, Vol. 2, p 159.
[14] ibid, Vol. 2, p 160.

lines located in high fire risk areas, rather than simply to SWER lines and 22kV feeders. This effectively responds to considerations of practicability.

Electricity lines operated by the regulated parties are essentially of four kinds, as follows:

SWER Lines
These are common, and operate normally at 12.7kV. It is unusual, but not unknown that these lines would share poles with other voltages (usually low voltage).

22kV lines
These are also common, and operate normally at 22kV. Although most 22kV poles would not share with other voltages, sharing with LV or 66 000 Volt lines is not uncommon.

Low voltage lines

Outside townships, there are very few distributor-owned Low Voltage lines. These are lower risk than high-voltage lines, but are not risk free. Moreover, low voltage lines are commonly installed on the same poles as other voltages, usually 22kV lines[15]

66kV Lines
These are sub-transmission lines and are the least common type. These 66kV lines commonly share poles with other voltages, usually 22kV.

As is apparent, the great majority of the relevant electricity lines are either 12.7kV SWER or 22kV lines, while the remaining lines are commonly co-located on the same poles as one or other of these types of line. Moreover, the small proportion of Low Voltage and 66kV lines are geographically 'intermingled' with the 22kV and SWER infrastructure. This means that it is inefficient to inspect them on a different cycle to the limited extent that they are the only lines on a given pole. Power company responses to the questionnaire circulated for this project, together with ESV's broader interaction with the sector make it clear that they would not operate their inspection cycle in such a way, even if the regulations were written in a way that strictly reflected the VBRC recommendation in this regard.

[15] In rare cases they may share with 66 000 volt lines or, more rarely still, with both 22 000 and 66 000 lines (ie three voltages on one pole).

3.2. *The costs of bushfires*

3.2.1. Incidence of bushfires

The Report of the Victorian Bushfires Royal Commission (Vol 1, Appendix C) summarised the incidence of major bushfires in Victoria between 1851 and 2007. Table 3.1 provides major statistics taken from the summary. It shows that Victoria has historically suffered an average of one major bushfire every three years and that an average of 2.5 people per year are killed by bushfire. More than 77 buildings are lost per year on average, while more than 83,000ha of land is burned.

Table 3.1: Incidence and consequences of major fires in Victoria 1851 - 2007 - summary statistics[16]

Statistic	Total (1851 - 2007)	Annual average
Number of fires	52	0.33
Total fatalities	391	2.5
Buildings lost	More than 12,000	More than 77
Area burnt	More than 13 million ha	More than 83,000 ha

These estimates do not include the Black Saturday fires. Adding those fires clearly increases these totals and averages significantly. For example, a total of 391 people had been killed by major bushfires in the 156 years prior to Black Saturday. Given that a further 171 people were killed on Black Saturday, the total over Victoria's history rises to 562 and the annual average to 3.6. Similarly, adding the 11 major fires occurring on Black Saturday to the 52 fires identified as having occurred in Victoria since 1851 raises the average number of fires per annum to 0.41, equivalent to one major fire every 2.5 years.

3.2.2. The Black Saturday bushfires

The costs of bushfires were also documented extensively by the Royal Commission. These costs include loss of life, serious injuries and substantial property damage. They also include the cost of fire suppression efforts and the costs of providing emergency assistance. The Commission's estimate of the total cost of the Black Saturday fires was approximately $4.4 billion. Table 3.2, below, is reproduced form the Royal Commission report and provides a breakdown of this figure. As the Commission inquired into 15 fires, this suggests that the average cost of each fire was of the order of $293.3 million.

Even these estimates arguably understate the true costs involved since, while estimates of the statistical value of the lives lost were included, the Commission did not seek to estimate injury costs. A

[16] Note that estimates are not available for all of the reported types of loss for all of the bushfires reported by the Commission. Hence, the totals and averages reported in this table necessarily constitute under-estimates.

subsequent analysis found that *"Most victims of the Victorian bushfires either died or survived with minor injuries"*[17]. However, that statement does not account for the impact of grief and psychological trauma which could not, in any case, be assessed in monetary terms.

Fires ignited by electricity asset failures were responsible for a very large proportion of these costs. For example, 70% of the 173 deaths due to the fires resulted from fires ignited by electricity asset failures. Evidence to the Royal Commission also indicated that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983[18].

<u>Table 3.2: Cost of the Black Saturday Bushfires</u>

Table A.1 Estimated major economic costs of Victoria's January–February 2009 bushfires: a summary

Item	Cost ($ million)	Source
RESPONSE COSTS		
Victorian Government—supplementary funding for fighting 2009 fires	593	Victorian Government Green Paper on the fire services levy
Value of CFA and other volunteer time plus additional costs incurred by the MFB, ADF, Victoria Police, SES, State Coroner's Office, NEO and DSE as a result of the fires	Not estimated	
DAMAGE COSTS		
General insurance claims paid	1,200	Insurance Council of Australia
Loss and damage to public infrastructure	77	Victorian Managed Insurance Agency
VBRRA—establishment costs, expenditure to date and projected further expenditure	1,081	VBRRA: *Rebuilding Together.* Includes VBRRA disbursements and planned disbursements from the Victorian Bushfire Appeal Fund and from other donors
Valuation of lives lost	645	Commission estimate
Loss of livestock and agricultural output	Not estimated	
Timber—value of destroyed timber, replanting costs for private plantations and salvage costs	658	Victorian Association of Forest Industries submission quoting VicForests
Asset damage and other costs incurred by Telstra and Melbourne Water. (Long-term impact on water supply was not estimated.)	25	Information from Telstra; Melbourne Water annual report for 2008–09
Cost of 2009 Victorian Bushfires Royal Commission, including costs incurred by state agencies in responding to the Commission	90	Victoria's 2009–10 Budget; Victorian Managed Insurance Agency
Total	**4,369**	

Source: Victorian Bushfires Royal Commission Report, Vol. 1, p 345.

[17] Peter A Cameron, Biswadev Mitra, Mark Fitzgerald, Carlos D Scheinkestel, Andrew Stripp, Chris Batey, Louise Niggemeyer, Melinda Truesdale, Paul Holman, Rishi Mehra, Jason Wasiak and Heather Cleland (2009). ***Black Saturday: the immediate impact of the February 2009 bushfires in Victoria, Australia.*** Medical Journal of Australia, Vol. 191 (1): 11-16

[18] Evidence of Tim Tobin SC. See: ***70% of deaths from power line failure: lawyer***. The Age, 10 September 2009.

3.2.3. Expected cost of bushfires

As noted above, the average cost of each fire that broke out on Black Saturday was almost $300 million. Similarly, the bushfires occurring in Canberra in 2003 were estimated to have a cost of $300 million, while the Ash Wednesday fires of 1983 were estimated to cost around $400 million.

Research conducted by the Bureau of Transport and Regional Economics (BTRE) in 2001[19] provides a broader database on the costs of bushfires. This research, which considered the costs associated with a wide range of natural disasters occurring across Australia over a period of more than three decades (1967-99) found that:

> *The costs ($2.5 billion) associated with bushfires represent a relatively small proportion (7.1 per cent) of the total disaster costs. However, as discussed later in this chapter, bushfires are the most hazardous type of disaster in terms of deaths and injuries.*

However, bushfire was found to be the fourth most frequent natural disaster costing more than $10 million.

The above estimate of the cost of bushfire in Australia over this period can be considered to be an underestimate of the true costs of bushfires for two main reasons. First, BTRE notes that it is not clear that the database it uses to generate these estimates includes the cost of forestry losses. These losses have constituted a major portion of the value of the losses in a number of recent fires, including those of Ash Wednesday (1983) and Canberra (2003). Secondly, the BTRE found that $1.4 billion of the $2.5 billion cost comprised the value of fatalities and injuries. However, the BTRE's Value of a Statistical Life (VSL) figure was only $1.3 million, while its figure for the cost of a serious injury was only $317,000. By contrast, currently used values for VSL, based on the Willingness to Pay (WTP) methodology are between $3.5 million and $6.0 million, while the valuation of a serious injury is typically 0.2 times these figures, or $0.7 - 1.2 million[20].

Substituting these figures suggests that the value of deaths and injuries over the period was in the range $3.8 - 6.5 billion approximately (i.e. 1.4 x (3.5/1.3) and 1.4 x (6.0/1.3) respectively). Moreover, the remaining $1.1 billion in costs (i.e. those not related to fatalities and injuries) is expressed in 1998 dollar terms in the BTRE paper. The current dollar equivalent is $1.6 billion[21].

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[19] Bureau of Transport and Regional Economics (2001). ***Economic Costs of Natural Disasters in Australia***. Report No. 103.

[20] The Office of Best Practice Regulation's *Best Practice Regulation Guidance Note* on VSL argues that an appropriate base case figure for VSL is $3.5 million. This figure is based on research by Abelson (2007). An alternative figure of $6.0 million has also been calculated by Access Economics on behalf of the Office of the Australian Safety and Compensation Council. Both of these figures are based on meta-analyses of relevant research, using Willingness to Pay (WTP) methodologies. See: Abelson, P. (2007). Establishing a Monetary Value for Lives Saved: Issues and Controversies. Paper prepared for the Office of Best Practice Regulation. See also: Access Economics (2008) *The Health of Nations: The Value of a Statistical Life.* Report prepared for the Office of the Australian Safety and Compensation Council. For a discussion of the valuation of a serious injury in WTP terms and the rationale for so doing, see: Soby, BA., Ball, DJ. & Ives, DP. (1993). *Safety Investment and the Value of Life and Injury.* Risk Analysis, Vol. 13, No. 3, June 1993, pp 365-370.

[21] CPI All Groups Australia December 2010 = 174.0, December 1998 = 121.9. 174.0/121.9 = 1.427. $1.1bn x 1.427 = $1.57bn.

The above implies that the best estimate of the current dollar costs of bushfires in Australia in the period studied by the BTRE is that it lies in the range $5.4 - 8.1 billion. This is equal to an average of $169 - 253 million per annum. As noted above, this adjusted figure still potentially excludes the value of property losses. The BTRE paper identified 22 bushfires over the relevant period that had caused damage in excess of $10 million in value. Given the above total cost (in 2011 dollar terms) of these fires of $5.4 - $8.1 billion, this implies an average cost per fire of $245.5 - 368.2 million. This is consistent with the figures cited above with respect to the Black Saturday fires, the Ash Wednesday fires and the Canberra fires of 2003.

The BTRE study estimated that the average annual cost to Victoria of bushfires in the years between 1967 and 1999 was $32.4 million. However, as demonstrated above, adjusting the national figures presented by BTRE for this period to account for currently accepted VSL values and update the figures for property damage to 2011 dollar values raises the BRTE estimates by a factor of 2.16 to 3.24. Applying these ratios to the estimated costs for Victoria over the period gives likely average annual costs of bushfires in Victoria of $70.0 - 105.0 million.

Moreover, recent research suggesting that the incidence of extreme weather conditions - including those that are conducive to bushfire - is increasing also suggests that the future costs of bushfires are likely to be substantially greater than the historic costs. For example, the UN Inter-Governmental Panel on Climate Change (IPCC) reported in 2007 with "high confidence" that Australia and New Zealand were already experiencing impacts from recent climate change, stating "*Heat waves and fires are almost certain to increase in intensity and frequency*"[22].   The New South Wales Government, in a 2010 review of the expected impacts of climate change on natural hazards profiles, similarly concluded that:

> *"The frequency of very high or extreme fire-risk days is projected to increase in the Riverina Murray and across New South Wales. Increases in temperature, evaporation and high-risk fire days are likely to influence fire frequency and intensity across the region, and the fire season is likely to be extended"*[23]

3.2.4. Cost of fires due to electricity assets

As suggested above, there is considerable uncertainty as to the overall contribution of electricity assets to the costs imposed by bushfires. While the Royal Commission found that only around 1.5% of all bushfire ignitions are due to this cause, it noted that such ignitions were most likely to occur in extreme conditions in which bushfires are most likely to have disastrous consequences. This observation has two important implications. First, the contribution of electricity assets to the overall cost of bushfires is inevitably far higher than this 1.5% of ignitions figure would imply.

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[22] Intergovernmental Panel on Climate Change (2007). ***Fourth Assessment Report***. Cited at: http://knowledge.allianz.com/health/science/?434/australia-bushfires-changing-climate-fans-the-flames
[23] Department Of Environment, Climate Change And Water (2010) **IMPACTS OF CLIMATE CHANGE ON NATURAL HAZARDS PROFILE RIVERINA MURRAY REGION**, p 8. NSW Government.

Second, the contribution of electricity assets to the cost of major bushfires is significantly greater than their contribution to the costs of all bushfires. The VBRC found[24] that around 70% of the Black Saturday fatalities were due to fires caused by electricity assets, while around half of the major fatal bushfires of 1969, 1977 and 1983 had been ignited due to electricity asset failures. Specifically:

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and
- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

Moreover, the Commission argued that the ageing nature of Victoria's electricity assets meant that their contribution to fire ignition, and hence bushfire costs, would increase in the future in the absence of policy action. This factor must also be weighed in determining the base case against which the potential benefits of the proposed regulations are to be weighed.

It must also be noted that the above estimates of the expected annual cost of bushfires relate *solely* to major bushfires (defined as those causing losses valued in exceed of $10 million, using the conservative BTRE methodology). Thus, the likely proportion of these costs attributable to failures in electricity assets is, as noted above, higher than that applicable to bushfires as a whole.

Given the combination of the above factors, particularly the observation that 50% of major fires occurring during the last three catastrophic bushfire outbreaks in Victoria (those of 1977, 1983 and 2009) were caused by electricity assets, an indicative estimate of the proportion of major bushfire costs likely to be attributable to electricity asset failures in the future, in the absence of specific policy action, of around 50% is considered reasonable.

As noted above, the total annual costs of major bushfires in Victoria are estimated to be in the range $70 - 105 million at present. If electricity asset failures are responsible for 50% of this total, the cost of fires caused by electricity assets could be of the order of $35.0 to $52.5 million per annum on average. In addition, there is the widely discussed probability that changing weather patterns will increase the incidence and severity of bushfires.[25] To the extent that this occurs, the expected future cost of bushfires will increase, leading to a proportionate increase in the expected cost of bushfires due to failures in electricity assets

3.3. Market failure issues

The electricity assets in question are privately owned. Asset owners have significant incentives to manage their assets in ways that reduce the likelihood of their contributing to bushfire ignition. These

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[24] See: Victorian Bushfire Commission (2009). ***Final Report***, Vol 2, Chapter 4.
[25] See, for example, the references cited in Section 3.2.3, above.

incentives derive in part from the fact that bushfires may cause significant damage to these assets, implying substantial costs to asset owners. In addition, where fires are caused by these assets, those who incur losses as a consequence will potentially take legal action to recover those losses from the electricity asset owners. Indeed, actions of this kind are currently underway following the Black Saturday fires. Furthermore, electricity asset owners may suffer due to negative community perceptions if it is believed that the ignition of fires resulted from a failure to maintain those assets adequately.

The presence of these incentives toward appropriate asset management/maintenance practices means that it is necessary to identify specific rationales for regulatory intervention to affect practice in this area. Two basic rationales can be identified: market failures and the need to maintain community confidence. These are considered in turn below.

Market failures of two types can be identified: externalities and differential discount rate issues.

3.3.1. Externalities

In practice, it is unlikely that legal action will be successful in forcing asset owners to bear all of the costs associated with fires caused by electricity assets. That is, it is unlikely that those who suffer property loss, are injured or have relatives who are killed by fires would be successful in being fully compensated for their losses via the legal system. Reasons for this inability to obtain full restitution would include the transactions costs of taking legal action, disincentives to taking action due to uncertainty as to the outcome, and uncertainties as to the cause of many fires leading to limited awards being made.

To the extent that parties suffering losses are unable to retrieve those losses from asset owners, those asset owners do not bear the full cost of the losses caused by those assets. This, in turn, will mean that they will have sub-optimal incentives to invest in inspection and maintenance activity to reduce the risks of fires being caused by electricity asset failures.

Recognition of these issues has led the Department of Primary Industries (DPI) to propose an "f-factor Scheme" to improve the market incentives for electricity businesses to reduce the contribution of their electricity assets to bushfire starts. In explaining the perceived need for such an approach, the Department has noted:

> *"Following the 2009 bushfires, concerns were raised that the existing incentive schemes do not adequately target the arrangements that electricity distribution businesses have in place to mitigate the number of fires caused by electrical assets. In addition, concerns have been raised that the current service incentive scheme provides greater incentives for electricity distributors to improve services in "high density areas" which are less exposed to bushfire risk than "low density areas".*

To address this concern, the Department of Primary Industries developed the concept of a financial incentive scheme (also referred to as an f-factor scheme) to encourage improvements in the management of electricity assets to reduce the number of fires started by electricity assets...

Through the f-factor scheme, the electricity distributors have a financial incentive to reduce the number of fires started by electrical assets where the costs to do so are less than the benefit received through the financial incentive scheme.

It is proposed that the f-factor scheme will operate in a similar way to the current service incentive scheme. It will balance the service/price trade-off by linking annual changes in the electricity distributors' regulated revenue to the number of fires started by its electricity distribution assets each year. However, while the service incentive scheme is based on averages and is therefore skewed towards "high density areas", the f-factor scheme will be based on absolute numbers and is therefore skewed towards areas where the likelihood of fires starting is higher."[26]

The issue remains a contested one, with electricity distributors arguing that efficient incentives to minimise the incidence of bushfire starts due to electricity asset failures already exist. For example, Jemena has argued in its submission in response to the DPI Consultation Paper:

"JEN considers that a distribution company's exposure to financial risk (e.g. potentially huge increases in insurance premiums and repair costs and public outrage resulting from a bushfire such as "Black Saturday" are itself sufficient drivers for it to manage its electricity assets to minimise the number of fire starts".

The extent to which market failure exists due to the incentives to minimise ignitions due to electricity assets being inefficiently small will necessarily be considered more closely as part of the above policy process to determine whether to introduce the proposed f-factor scheme and, if so, in what form. However, as the above indicates, it is the current view of DPI that such market failures do exist and require changes in the incentives in order to improve economic efficiency. The substantial program of action to reduce electricity asset caused bushfire ignition recommended by the Royal Commission also clearly indicates that the Commission has taken the view that adequate (i.e. economically efficient) market incentives on electricity companies do not currently exist.

3.3.2. Differential discount rates

It is widely argued to be a feature of the current operation of investment markets, including arrangements for incentive based remuneration, that company managers face strong incentives to

[26] Department of Primary Industries (2011). ***Establishing a financial incentive scheme to reduce fire starts from electricity distribution assets - the F-Factor: Consultation Paper.***

maximise short-term profits, even at the expense of higher long-term rates of return. Even in the absence of these specific incentives, it is likely that the effective discount rate applied by company management, which is based on the cost of capital, will be higher than the implicit social discount rate - the latter concept being based on the social "rate of time preference"[27]. This reflects the fact that the latter concept is not based on the cost of capital *per se*.

If the discount rate applied by company management in determining expenditure decisions is higher than the social discount rate they will have insufficient incentive (vis-à-vis the social optimum) to spend money in the short term to avert longer term harms. This may constitute another contributing factor toward inadequate maintenance expenditures being undertaken voluntarily.

3.3.3. Maintaining community confidence

As discussed below, while electricity assets are responsible for the ignition of only a small proportion of the overall number of bushfires, they are responsible for a much larger proportion of major bushfires occasioning large scale damage and loss of life. As documented in the report of the Victorian Bushfires Royal Commission, electricity assets have been responsible for the ignition of a large proportion of the fires occurring on each of the last four major bushfire events in Victoria; those of 1969, 1977, 1983 and 2009. Moreover, fires ignited by electricity assets caused a majority of the fatalities recorded on Black Saturday.

ESV believes there is a high level of awareness of these facts in the general community, given the wide publicity given to the work of the VBRC. Moreover, the fact that a class action against a major electricity company (MEC) has been commenced, suggests that there is a level of dissatisfaction with the performance of these organisations in managing bushfire risks. In this context there is a need to act to ensure that community confidence in the safety of electricity infrastructure is re-established and that people can be confident that these assets are being appropriately managed.

[27] The rate of time preference pertains to how large a premium a consumer places on enjoyment nearer in time over more remote enjoyment. The higher the time preference, the higher the discount placed on returns receivable or costs payable in the future. The social rate of time preference is defined as the rate of time preference of society as a whole. In general, the social rate of time preference is regarded as relatively low, implying that society as a whole discounts long-term projects less than individuals do.

4. Summary of the proposed regulations

Parts 8 and 10 of the *Electricity Safety Act 1998* provides that operators of "at risk" electricity assets must prepare and submit to ESV for approval a Bushfire Mitigation Plan (BMP). The principal regulations set out details of the required contents of these BMP.

The proposed regulations will effectively replace the *Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010*. The latter regulations amend the principal regulations in three substantive respects:

- They state that BMP must include an inspection plan that ensures all of the affected "at risk" electricity assets are inspected at intervals not exceeding 37 months;
- They state that BMPs must include details of processes and procedures to ensure that only persons who have completed training courses approved by ESV carry out the required inspections;
- They state that BMPs must detail the processes and procedures by which affected companies will monitor and audit the implementation of their BMP and the effectiveness of the inspection program and identify and remedy any deficiencies.

A new qualification aimed at electricity asset inspectors has been developed and accredited under the Vocational Education and Training framework. This is the Certificate II in Asset Inspection (Code 22109VIC). To date, one Registered Training Organisation (RTO), Central Gippsland TAFE, has been accredited by the Victorian Registration and Qualifications Authority (VRQA) to deliver this qualification.[28] ESV expects shortly to declare this qualification to be an approved qualification for the purposes of the interim and proposed regulations and to approve Central Gippsland TAFE as a provider of this qualification.

As noted above, the proposed regulations are intended to replace the interim regulations without substantive amendment. This will have the practical effect of maintaining these provisions in operation within the context of the principal regulations until the sunsetting of the latter in 2013.

[28] http://www.vrqa.vic.gov.au/StateRegister/Qualification.aspx/DetailsQualification?QualificationID=ed6bcb3e-7c06-e011-bba1-00145e369940

5. Expected costs of the proposed regulations

5.1. Data sources and approaches

In order to obtain the best possible data on the expected costs of compliance with the proposed regulations a questionnaire was developed and sent to a wide range of affected parties during January 2011. The questionnaire sought data on the following issues:

- The cost of complying with the principal regulations as they existed prior to the adoption of the interim regulations;
- The inspection frequencies adopted under the principal regulations;
- The incremental costs expected to be incurred as a result of the provisions contained in the interim regulations and their extension in effect by the proposed regulations; and
- The specific cost impacts of each of the substantive provisions of the proposed regulations.

Questionnaire responses were obtained from all five electricity distribution businesses and from a total of eight "specified operators". Specified operators are defined in section 83A of the Electricity Safety Act 1998 as operators of at- risk electric line(s) that are not "major electricity companies" (MECs). Electricity distribution and transmission businesses are all classified as MECs.

The specified operator category comprises a disparate range of businesses, including those involved in electricity generation, rail operations, rail infrastructure and tram operations and other major businesses, including Melbourne Airport, Melbourne Water and Alcoa. The Department of Defence is also considered to be a specified operator. ESV has identified 16 specified operators to date. However, there may be other organisations that meet the above definition and will, as a result, be required to comply with the regulations. Prior to the commencement of amendments to the Electricity Safety Act 1998 and the adoption of the interim regulations in October 2010, the BMP requirements applied to "electricity suppliers". The definition of electricity supplier included all MECs and a proportion of those now classified as specified operators. However, a number of specified operators have been brought within the scope of the BMP requirements for the first time as a result of the legislative amendments and the adoption of the interim regulations.

The questionnaire responses formed the basis of the following cost estimates. Average cost figures were calculated, in some cases incorporating adjustments or inclusions to take account of identified or suspected data quality issues. It should be noted that the recent adoption of the interim regulations mean that ESV has yet to approve amended BMP that comply with the new requirements. This issue was identified by a number of MECs and different cost estimates based on two possible interpretations of the regulatory requirements by ESV were accordingly provided. These different estimates have been used to develop two distinct cost scenarios, which are detailed below. Given that the process of determining what approach to compliance will be adopted has not yet been completed, it is not possible to specify a base case with respect to these costs. The two scenarios are instead presented as alternative possibilities that are implicitly given equal probability.

It should be noted that a number of respondents highlighted the commercially sensitive nature of some of the material being supplied and indicated that they did not wish this information to be published in an identifiable form. The questionnaire responses were, in many cases, obtained on the basis of an assurance of compliance with these requests. Consequently, the following estimates are presented in aggregated form and only a limited amount of more disaggregated material has been able to be provided.

5.2. Incremental costs: electricity distribution businesses

5.2.1. Current arrangements

For electricity distribution businesses, the annual cost of inspecting power lines pursuant to BMPs under current arrangements (i.e. not taking account of the requirements of the interim regulations) was estimated at $8.6 million. Inspection activity was largely carried out under contract by third parties and the costs incurred varied little from year to year. Inspection intervals ranged from 3 to 5 yearly in most cases, with a 10 year interval being common for concrete power poles.

Some respondents noted that significant recent changes to their practices had been made. These changes reflected, in part, a desire to adopt new technology to improve the effectiveness of inspections and lower their costs, in the pursuit of business efficiencies. They also reflected, in part, the companies' response to the recommendations of the VBRC report and its recommendations.

Two related changes to inspection practices were identified that are currently in the process of being implemented. These are the use of high resolution digital photography and the use of aerial inspections. Digital photography is used to obtain better information as to the state of pole-top fittings, in a context in which it is necessary as a matter of practicability to conduct most inspections from ground level. Remote devices are employed in most cases to assist in obtaining better images. However, the use of aerial photography - specifically by mounting digital cameras on helicopters - is increasingly being seen as a viable means of conducting some inspection activity. Indeed, one major distribution business currently has an aerial inspection program in place to supplement its program of ground based inspections, while the second major distribution business affected by the proposed regulations intends to move in this direction, should the regulations be interpreted in a way that will allow this to occur.

5.2.2. Incremental costs of 37 month inspection cycle

A limitation of aerial photography as an inspection mechanism is that it does not allow for a direct assessment of the structural integrity of the electricity pole itself to be made. Consequently, the preferred approach of respondents currently using aerial photography is to use a mix of aerial and ground based inspections, with assets being inspected by both means on an alternating schedule. It is therefore likely that modified draft BMP submitted to comply with the interim and proposed regulations would adopt this approach, implying that all assets would receive either a ground based or an aerial inspection at least every 37 months.

However, it is yet to be determined whether such an approach would, if it did not contain ground-based inspections at less than 37 month intervals, be assessed by ESV as being compliant with the regulations. Assessments of proposed BMP will need to be made after they have been developed and submitted to ESV and will need to take into account the specifics of the aerial inspection methodology proposed as well as an assessment as to whether the proposed BMP would adequately comply with the broader duties contained in the Act and regulations.

It is this uncertainty that caused two major distribution businesses to provide alternative estimates of the cost of complying with the 37 month maximum inspection cycle aspect of the proposed regulations. The following two cost scenarios are based on a) a situation in which aerial inspections are judged, within the context of the BMP submitted, to constitute a part of the inspection cycle for the purposes of the regulations and b) a situation in which ground based inspections must be conducted at least every 37 months.

Based on these differential estimates, two incremental cost scenarios have been constructed. Average annual inspection costs under the two scenarios and the incremental costs associated with each scenario are summarised in Table 5.1 below. It should be noted that the two major distribution companies both indicated that their expected least cost response to the proposed regulations would be to move from their current 5 year inspection cycle to a 2.5 year cycle, rather than the minimum 37 month cycle specified in the regulations.

Table 5.1: Cost of moving to a 37 month inspection cycle

	Annual average	**Life of the regulations**
Current inspection cost	$8.6 million	$25.8 million
Inspection cost (scenario A)	$10.6 million	$31.8 million
Incremental cost (scenario A)	**$2.0 million (+23.3%)**	**$6.0 million**
Inspection cost (scenario B)	$16.4 million	$49.2 million
Incremental cost (Scenario B)	**$7.8 million (+90.7%)**	**$23.4 million**

Table 5.1 shows that the move to a 37 month inspection cycle will increase annual inspection costs by between $2.0 million and $7.8 million. This is equivalent to increases of 23.3% and 90.7% respectively on current inspection costs. In practical terms, the regulations are assumed to have a three-year life. However, this includes the lifespan of the current interim regulations. That is, the BMPs to be approved in 2011 will, for the first time, be required to incorporate the 37 month inspection cycle contained in the interim regulations and expected to be carried over into the proposed regulations. While the proposed regulations will sunset in 2013, the BMPs approved under those regulations will remain in force until mid 2014.

Given these assumptions, the expected total cost impact of both the proposed regulations and the interim regulations is set out in the last column of Table 5.1. This shows that the regulations will have an incremental cost totalling between $6.0 million and $23.4 million over three years. Strictly speaking however, only two thirds of this amount is attributable to the proposed regulations, given that the interim regulations have already been adopted.

5.2.3. Incremental cost of qualifications requirements

As noted above, all distribution businesses stated that most or all of their inspection activity was contracted to third parties. Given this, the major impact of the qualifications requirements contained in the proposed regulations was expected to be an increase in the contracted cost per inspection. This cost increase was expected to arise as a result of the need for contractors to recover the costs of training their employees to meet the new qualifications requirements.

Two respondents estimated this cost as being likely to equate to an ongoing 10% increase in inspection costs. A third respondent was unable to provide an estimate of this cost. A fourth respondent was unaffected by the proposed regulations, due to not having at risk electricity lines within their network[29]. A fifth respondent provided "one off" cost estimates equal to approximately 16 - 17% of the estimated annual cost of inspection under a 37 month inspection cycle.

It can be expected that providers of inspection services will need to train existing staff to a level consistent with the required qualifications, to hire staff who possess these qualifications or, most likely, to undertake some combination of these two courses. This implies that they will incur some short-term training costs and some ongoing costs in the form of the need to pay higher wages to qualified staff. Given that they operate in a competitive market, it can be expected that they would seek to recover these costs through higher contract prices for undertaking inspection activity, rather than seeking to pass on the short-term costs of training activity. Thus, in an environment in which all distribution businesses state that they employ third parties to undertake the required inspection activity, it is

[29] it is proposed to amend the Electricity Safety Act 1998 in 2011 to require an MEC to prepare and submit a plan for the mitigation of bushfire risks in relation to the whole of its supply network, not just those parts that are considered to be "at-risk" by reason of location.

considered preferable to model the impact of the proposed qualifications requirement as an ongoing increase in unit inspection costs, rather than as a one-off increase. Thus, the cost of the qualifications requirements has been modelled as an ongoing 10% increase in inspection costs.

The total costs of inspection activity under the proposed regulations have been estimated above at $8.6 - 16.4 million annually. This implies that the incremental costs of the qualifications requirements are likely to fall within the range $0.86 - 1.64 million per annum.

5.2.4. Incremental costs of monitoring and review activities

As noted in Section 4, the proposed regulations also contain, for the first time, specific requirements for the monitoring of BMP implementation and the identification of deficiencies, including monitoring of the effectiveness of the inspection program and addressing any deficiencies found.

Four distribution businesses believed that they would incur additional costs as a result of these provisions, while the fifth believed that their existing processes would be regarded as compliant. In each case, the potential additional costs identified related to engaging external auditors to demonstrate that the required assessments had been undertaken.

Two of the distribution businesses estimated the additional costs involved at $50,000 per annum, while a third estimated the costs at $100,000 per annum. The fourth distribution business stated that they believed their existing processes to be adequate but highlighted the possibility that they would be required to incur additional costs to demonstrate compliance adequately. These contingent costs were estimated at up to $500,000 per annum. ESV notes that the actual size of the costs incurred will be determined in the context of discussion and negotiation with MECs in the process of approving updated BMP. Given this, the fact that the estimate involved was substantially larger than those provided by the remaining respondents and the uncertainty expressed by this respondent as to whether these costs would be incurred in practice, it is believed that the additional costs actually incurred are unlikely to exceed $100,000 per annum in this case. Consequently, the annual cost these activities for the distribution sector as a whole has been estimated at $300,000.

5.2.5. Other identified costs

The questionnaire also asked respondents to identify any other costs that would be incurred as a result of the provisions contained in the interim regulations and the proposed regulations. Costs of training internally employed inspectors were identified by two distribution businesses, notwithstanding that they stated that their inspection activities were substantially completed by third parties. These businesses may maintain some degree of internal inspection capacity in addition to the employment of externally contracted services, potentially in order to be able to respond to specific issues highlighted to them.

These costs of additional training of internally employed inspectors totalled $30,000 per annum. No other businesses identified additional costs. Thus, the total cost identified among MECs was $30,000 per annum. This cost has been included.

5.2.6. Additional maintenance costs

In general, the proposed requirements for more frequent and higher quality inspections to be undertaken are predicated on the view that an improved inspection regime will lead to earlier identification of faults in electricity lines. This enables these faults to be addressed in a more timely manner and thereby reduces the incidence of failures leading to bushfire ignition. In large part, it is expected that the need to address this larger number of identified faults over the medium term will result in reallocation of expenditures within the existing maintenance budget.

This reflects the basis of the system of economic regulation governing the industry, in which maintenance budgets are agreed as part of the five-yearly price reset process overseen by the Australian Energy Regulator (AER). Questionnaire responses indicated that affected parties largely expected to meet their obligations under the proposed regulations within the context of current price/revenue/cost arrangements, albeit that some noted that the adoption of Scenario B could lead to an attempt to pass through additional costs.

Conceptually therefore, the expected benefits of the regulations are expected largely to be obtained by means of a reallocation of maintenance expenditures to higher-productivity ends. However, given the possibility that additional expenditure could be required in order to respond in a timely way to all critical faults identified through the enhanced inspection regime, respondents were asked to estimate the size of any additional maintenance costs that they expected to incur.

Only one MEC stated that they expected maintenance expenditures to be brought forward to some degree. That respondent nominated a five-year time horizon over which this impact was expected to be felt and estimated that maintenance expenditures could increase by around $50,000 per annum over this time. One other respondent characterised the expected increase in maintenance expenditures as being "negligible", while others did not identify any additional costs. One specified operator also referred to the possibility that expenditures would be brought forward, but provided no quantitative estimate.

Given that the MECs are expected to bear the great majority of the incremental costs associated with the proposed regulations (See Section 5.4, below), this suggests that bringing forward of maintenance expenditures will amount to only around $50,000 per annum over the three-year effective life of the regulations. It should be noted that this does not represent additional expenditure, but a re-timing of existing expenditures. Thus, in present value terms, the additional cost incurred is equal to the time value of this cost: i.e. the relevant discount rate must be applied to the $150,000 in costs brought forward. If, for example, this expenditure is brought forward by an average of two years, the additional cost incurred would be equal to approximately $10,684[30].

5.3. Costs to specified operators

5.3.1. Current arrangements

Six specified operators provided estimates of the inspection costs they currently incurred. Given that this group has not to date been subject to the BMP requirements, these costs can be considered to be "business as usual" costs; that is, costs that are incurred by these companies for commercial reasons. These reported *ex ante* costs varied widely, from $600 to $181,400 per annum, reflecting the widely varying nature and scale of the at risk electrical lines operated by these companies. This wide variation in turn reflects the widely differing nature of the activities undertaken by these firms. The variation observed necessarily introduces an element of uncertainty as to the calculation of average costs for this group. However, the eight responses received from operators in this sector represent approximately half of the companies identified to date by ESV as being affected by the proposed regulations. Hence, estimates based on these responses are likely to be reasonably representative.

The total annual cost of current inspection activity among the six respondent companies was $261,700, implying average annual costs per company of $43,600.

5.3.2. Incremental costs of 37 month inspection cycle

Four of the respondents provided quantitative estimates of the incremental costs of moving to a 37 month minimum inspection frequency. Two of these respondents stated that there would be no impact on their operations, as their current inspection frequency already met or exceeded the proposed requirements. The remaining two respondents estimated cost increases averaging $7,000 and $15,000 per annum. Thus, the total cost increase among this group of four respondents was expected to be $22,000 per annum and the average increase per respondent was $5,500 per annum.

ESV has identified a total of 16 specified operators likely to be affected by the proposed regulations. This implies that the incremental costs for this group as a whole of moving to a 37 month minimum inspection cycle is likely to be (16 x $5,500) = $88,000 per annum.

[30] Assumes a 3.5% real discount rate, as per VCEC guidance materials.

5.3.3. Incremental costs of qualifications requirements

Responses to the question of what would be the cost impact of the proposed requirement for all inspectors to meet minimum qualifications standards varied widely among this group. Seven responses were received to this question. Two respondents indicated that there would be a zero or minimal cost impact. Both of these respondents undertook relatively large-scale inspection activities, with one contracting this activity to a third party and the other undertaking a mix of in-house and third party inspections. A third respondent estimated the cost increase at 11%, while a fourth estimated a 20-30% increase. These respondents also had relatively large scale inspection activities and contracted these tasks to third parties.

Two respondents whose current costs were very small estimated increases of 67% and 100% respectively. In one case this was based on an assessment that they would move from their current internal inspection regime to an external regime. In the other case, it was anticipated that they would train their current internal inspectors to the required standard. The seventh response was speculative in nature and, given the absence of a specific estimate of current inspection costs, cannot be assessed in term of a proportionate increase. This response has therefore been excluded from the analysis.

The total incremental cost among the six respondents was $29,100. This represents an increase of 11.1% on the current cost base of $261,700 for this group and an average increase of $4,850 per respondent. On the basis of an estimated 16 affected operators, the expected annual cost of the qualifications requirements is $77,600.

5.3.4. Incremental costs of monitoring and review activities

Six responses were received to the questions regarding the incremental cost of these requirements. Three of the respondents stated that they did not expect to incur any additional costs as they believed that their current monitoring and review arrangements would be held to be compliant with the new requirements. A fourth respondent noted that they already employed an external auditor for this purpose but speculated that they may increase the amount of external audit activity, at a cost of around $1,000 per annum.

Neither of the two remaining respondents currently employed an external auditor and both speculated that they may need to take this step in order to comply with the requirements. However, estimates of the likely incremental costs varied widely, with one estimate at $1,000 and the second at $10,000. While this respondent has relatively large scale electricity assets, this estimate is clearly well outside the range of the remaining five respondents and may be somewhat speculative in nature.

The average incremental cost of monitoring and review activities is $2,000 per respondent. Given the 16 specified operators expected to be affected by the proposed regulations, this implies total annual costs of $32,000.

5.3.5. Other identified costs

Four responses were received to the question of whether any other cost impacts could be identified in connection with the proposed regulations. Two respondents stated that they did not foresee any additional costs, while a third stated that they had not yet assessed this question. Only one respondent identified specific additional costs. These were costs of $8,300 per annum approximately arising due to an expectation that increased inspection activity would lead to a higher rate of electricity outages. That is, this estimate was predicated on an assumption that lines could not be live when inspection was being undertaken.

The average expected cost in this regard is therefore approximately $2,075 per annum. Given the expectation of 16 affected entities, the average of "other" identified costs is therefore $33,200 per annum.

5.3.6. Increased maintenance costs

Five responses were received to the question of whether and by how much maintenance costs were expected to increase as a result of the enhanced inspection requirements contained in the proposed regulations. Four stated that they did not expect any significant increase in maintenance costs to result. The fifth respondent stated that they had yet to undertake a quantitative assessment of likely maintenance costs but that they considered it possible that these could be increased by between 20% and 50%. However, no dollar figure on either current maintenance expenditure or expected increases in maintenance expenditures were provided.

Overall, the responses received were consistent with those of the distribution businesses, which indicated that they did not believe that increased inspections would yield significant or measurable changes in maintenance expenditures.

5.4. *Cost summary*

Tables 5.2 and 5.3, below, summarise the above cost analysis. They show that the expected annual costs of the regulations for distribution businesses lie in the range $3.22 - 9.8 million per annum, while the expected costs for specified operators are $0.23 million per annum[31].

Thus, the total annual costs of compliance are expected to be in the range $3.4 - $10.0 million per annum. Over three years (i.e. the expected period of operation of the interim regulations and the proposed regulations), this is equivalent to between $9.5 million and $28.0 million in present value terms.

Table 5.2: Total costs - distribution businesses

	Scenario A	**Scenario B**
Inspection costs	$2.0 million	$7.8 million
Qualifications	$0.86 million	$1.64 million
Monitoring & review	$0.3 million	$0.3 million
Other	$0.03 million	$0.03 million
Total	$3.19 million	$9.77 million
Total over the life of the regulations (present value)	**$8.88 million**	**$27.37 million**

Table 5.3: Total costs - specified operators

Item	**Cost**
Shortened inspection cycle	$88,000
Qualifications requirements	$77,600
Monitoring and review	$32,000
Other	$33,200
Total	$230,800
Total over the life of the regulations (present value)	**$646,618**

[31] These latter costs are calculated on the basis of there being 16 specified operators (SOs) affected by the proposed regulations - a number which represents the number of SOs identified to date by ESV. To the extent that additional businesses fall within the definition of a specified operator and are required to comply with the proposed regulations, additional costs will be incurred. However, as the above data indicate the expected costs to this group represents only a very small proportion of the total costs expected to arise from the regulations. Thus, the identification of additional SOs is unlikely to have a substantial impact on the total regulatory cost calculations made here.

6. Expected benefits of the proposed regulations

6.1. Overview

As noted above, the expected benefits of the proposed regulations arise from anticipated reductions in the incidence of bushfire caused by failures of electricity assets. These reductions are expected to arise as a result of improved maintenance performance. The improvements in inspection frequency and quality that will result from the adoption of the proposed regulations are expected to lead to faults being identified earlier than at present, on average, and corrective action consequently being taken at an earlier stage. Better maintenance should lead to a reduced failure rate and, consequently, a reduced incidence of bushfire ignition.

The extent of the improvement that can be anticipated is necessarily uncertain. In large part, this uncertainty derives from the relatively limited frequency of bushfires and the still more limited frequency of bushfires ignited by electricity assets. In addition, there is clearly uncertainty as to the likely practical effectiveness of the proposed regulatory changes in improving actual maintenance practices.

The questionnaire responses received provide some guidance on this issue. The responses from the major electricity companies, who hold the preponderance of electricity assets in bushfire prone areas, indicate that the most common inspection frequently is currently five years, or ten years in the case of concrete electricity poles. Questionnaire responses indicated that there would in most cases be a move to inspections at 2.5 year intervals in response to the proposed regulations. While a 37 month interval is allowed in the regulations, a number of respondents indicated that a 2.5 year cycle would be likely to be chosen as this harmonised better with other aspects of the company's commercial operations.

Given this, it appears that there will be an approximate doubling in the number of inspections carried out in relation to most assets in high bushfire risk areas, as well as an improvement in the average quality of inspections due to the implementation of qualifications requirements for inspectors. A doubling of inspection frequency should substantially reduce the period elapsing between a fault occurring and that fault being detected and remedied. Thus, the impact of the proposed regulations could be quite large.

That said, one large distribution business indicated that they did not believe that significant changes to fault detection and maintenance practice would occur as a result of the implementation of these regulations. This business argued that its current inspection program is based on an explicit analysis of maintenance requirements and that the soundness of this analysis is demonstrated by the small number of in-service powerline asset failures currently experienced.

Moreover, this organisation noted specifically that analysis of the current five year maintenance cycle showed no correlation between the time elapsed since an inspection had been conducted and the likelihood of an asset failure. That is, failures occurred equally frequently among recently inspected assets and those approaching the time for their next scheduled inspections. This observation can clearly be interpreted as indicating that the current inspection frequency is adequate. Conversely, two factors can be weighed:

- That a poor failure identification rate during inspections could reduce the observed correlation between inspection time and failures; and
- That the increasing average age of electricity assets implies a need for inspection frequencies to be increased in the future, as suggested by the VBRC.

In light of the uncertainties involved, a break-even analysis has been developed below. The results of this analysis are compared with the identified costs and analysed in the conclusions section following.

6.2. Break-even analysis

As set out in Section 3, above, based on VBRC data, Victoria has faced a major bushfire approximately every 2.5 years over the past 160 years. The analysis conducted by BTRE, adjusted to present the results in present dollar values and based on currently accepted VSL figures, suggests that the average cost per bushfire lies in the range $245.5 - 368.2 million. Similarly, the VBRC's analysis indicates that the average cost for each of the 15 major Black Saturday fires that it investigated was approximately $300 million. The 2003 Canberra bushfires were estimated to have cost $300 million, while the 1983 Ash Wednesday fires in Victoria were estimated to have cost $400 million.

Given these estimates, a conservative figure for the average cost of a major bushfire of $300 million has been adopted for the purposes of this analysis. This implies that the average annual cost to Victoria of major bushfires is $300/2.5 = $120 million.

The second factor to be considered is the contribution of electricity assets to bushfire ignition. The VBRC found that in long-term average terms, only around 1.5% of bushfire ignitions were due to electricity assets. However, the likely contribution of electricity assets to the cost of bushfires is much greater than this figure would suggest, since the likelihood of ignition due to electricity assets is much higher when weather conditions are such as to lead to an elevated likelihood of a fire developing into a major fire, leading to large scale losses. Thus, the contribution of electricity assets to losses from bushfires is much larger than their contribution to bushfire ignitions. The VBRC found[32] that that major fatal fires had been ignited due to electricity asset failures in 1969, 1977 and 1983. Specifically:

[32] See: Victorian Bushfire Commission (2009). ***Final Report***, Vol 2, Chapter 4.

- 9 of 16 major fires occurring on February 16, 1977 were caused by electricity assets;
- 4 of 8 fires occurring on Ash Wednesday 1983 were caused by electricity assets; and
- 5 of 11 major fires occurring on Black Saturday 2009 were caused by electricity assets.

Moreover, 70% of the 173 deaths due to the Black Saturday fires resulted from fires ignited by electricity asset failures. The Commission also cited evidence to the inquiry into the 1977 fires from the then Chairman of the SEC, as follows:

> *"This overall picture is in sharp contrast to what happens on days of extreme conditions, such as January 8th 1969 or February 12th 1977. On such days, the incidence of SEC fires rises dramatically.*
>
> *The alarming aspect of these figures is that they tend to occur in widely separated places at approximately the same time and at the time of day when conditions are such that the rate of spread of fire is likely to be at its peak"*

Based on these factors, and in particular the observation that 50% of major fires occurring on each of last three occasions on which disastrous bushfires occurred in Victoria (i.e. in 1977, 1983 and 2009), it is speculated that the contribution of electricity assets to losses from bushfire is in the order of 50%. Moreover, the ageing of the electricity infrastructure, as highlighted by the Commission, suggests that this percentage would be likely to increase in future years in the absence of any policy action. As discussed in Section 3, above, the VBRC cited a range of research which indicated that rapidly increasing equipment failures could be expected in the near future in the absence of significant changes to the management of electricity assets. This implies that the contribution of electricity assets to losses from bushfires would be likely to reach this 50% level in the near future, in the absence of policy action, even if the current contribution of electricity assets to losses is considered smaller than this amount.

Thus, the base case scenario suggests that around \$120 million x 50% = \$60 million per annum in bushfire related costs, on average, would be incurred in the future due to failures in electricity assets, in the absence of policy action such as the adoption of the proposed regulations.

The costs of the proposed regulations have been estimated at between \$3.45 million and \$10.03 million per annum. This implies that the regulations will break even - i.e. that the benefits associated with the regulations will at least equal the costs incurred - if they are responsible for a reduction in electricity asset-related losses from bushfires of around 5.8% - 16.7%.

7. Identification and analysis of feasible alternatives

Overview

Four alternatives to the proposed regulations have been identified. The first of these is very similar to the proposed regulations and differs only in that, in line with VBRC Recommendation 28, it would limit the requirement for a maximum three year inspection cycle to SWER lines and 22kV feeder lines, rather than applying it to all high risk assets.

The second and third alternatives differ from the proposed regulations in that they would apply maximum inspection frequency requirements that varied with asset age, whereas the proposed regulations set a single inspection frequency for all electricity assets in high bushfire risk areas. The alternative approach of applying differentiated inspection frequency requirements is based on the observed relationship between expected failure rates and asset age, as represented in Graph 3.1, above. Alternatives of this type therefore constitute examples of a *risk based assessment regime,* which is increasingly seen as a regulatory best practice[33]. The key benefit expected to result from adoption of such an approach is increased effectiveness of inspection activity. That is, because inspection activity is more closely focused on older assets known to be more likely to fail.

This improvement in effectiveness has the potential to ensure that that a larger proportion of imminent asset failures will be detected and remedied in a timely manner than would otherwise be the case, for a given inspection budget. Alternatively, as indicated in the Hampton Report, a given level of inspection effectiveness can potentially be achieved at lower cost. Alternative 1, below, focuses on using inspection targeting based on asset age as a means of increasing fault detection rates. Alternative 2, on the other hand, focuses on the potential for such targeting to reduce the cost of achieving a given level of fault detection via asset inspections.

The fourth alternative discussed below would regulate the qualifications of asset inspectors, without requiring a specific frequency of inspection. Rather, the existing arrangement in which the asset inspection frequency proposed by the electricity company would need to be assessed and approved by ESV in the context of the overall BMP proposal would be retained. This alternative has the benefit of retaining flexibility regarding asset inspections in recognition of different circumstances and different broad approaches to mitigating bushfire risk.

Interstate requirements

[33] See, for example, Hampton, P. (2005). *Reducing Administrative Burdens: Effective Inspection and Enforcement.* HM Treasury, United Kingdom Government.

It is a requirement of the Victorian Guide to Regulation that consideration should be given to the approaches taken to dealing with an identified regulatory problem in other Australian States and Territories and, where a less onerous approach is adopted in other states, evidence should be provided as to why this is not appropriate in the Victorian context.

ESV understands that no other state currently regulates the required qualifications of asset inspectors or the frequency of asset inspections. However, it should be noted that the structure of the Victorian electricity industry differs substantially from that found in other states. While Victoria's electricity industry was substantially restructured during the 1990s to become a privately-owned and competitively structured industry, this major structural change has not been replicated to the same extent in the other States that form part of the National Electricity Market (NEM). Victoria and South Australia are currently the only states with industries characterised by privately owned electricity distribution businesses, although South Australia adopted a 99 year lease arrangements. Just as Victoria did not adopt explicit regulation of a wide range of industry practices at the time that its electricity industry was structured as a government monopoly, instead adopting internal arrangements within the former SEC, it is unsurprising that states with predominantly government owned industries would not seek to adopt explicit regulation in this area. Thus, the different structure of the Victorian electricity industry can be considered as a key reason for less interventionist approaches currently adopted in other states being inappropriate in the Victorian context.

That said, ESV understands that a number of states are currently giving consideration to adopting the Certificate II in Asset Inspection as the default qualification requirement for asset inspectors in the near future. While this qualification is currently accredited only within Victoria, it is expected shortly to become a nationally accredited qualification. It is not currently known whether the qualification will be adopted as an explicit regulatory requirement or as a matter of internal policy/regulation within electricity distribution organisations in the various states.

7.1. Alternative 1: Applying a maximum inspection frequency of three years only to SWER lines and 22kV feeder lines

As discussed above, this alternative differs from the proposed regulations essentially in that it would limit the application of the maximum inspection frequency requirement to SWER lines and 22kV feeder lines, rather than applying it to all at risk assets. Electricity lines operated by the regulated parties are essentially of four kinds, as follows:

SWER Lines
These are common, and operate normally at 12.7kV. It is unusual, but not unknown that these lines would share poles with other voltages (usually low voltage).

22 kilovolt lines

These are also common, and operate normally at 22kV. Although most 22kV poles would not share with other voltages, sharing with LV or 66kV lines is not uncommon.

Low voltage lines

Outside townships, there are very few distributor-owned Low Voltage lines. These are lower risk than high-voltage lines, but are not risk free. Moreover, low voltage lines are commonly installed on the same poles as other voltages, usually 22kV lines[1]

66 kilovolt Lines

These are sub-transmission lines and are the least common type. These 66kV lines commonly share poles with other voltages, usually with 22kV lines but sometimes with low voltage lines.

As is apparent from the above, the great majority of the relevant electricity lines are either 12.7kV SWER or 22kV lines, while the remaining lines are very often co-located on the same poles as on or other of these types of line. Moreover, the small proportion of Low Voltage and 66kV lines are geographically ‘intermingled’ with the 22kV and SWER infrastructure.

7.1.1. Expected benefits of the alternative

All above-ground electricity assets in high bushfire risk areas have the potential to cause bushfire ignition. However, as the VBRC recommendation recognises, the bulk of the ignition risk is caused by SWER lines and 22kV lines. This reflects two factors: that they are predominantly the kind of above ground assets found in high risk areas and the fact that higher voltage lines generally entail higher risk than lower voltage lines.

Given that there is some risk of both low voltage lines and 66kV lines causing bushfire ignition, the alternative of excluding these assets from the scope of the increased inspection requirements, as proposed by the VBRC, would necessarily entail a reduced level of benefits, vis-à-vis the proposed regulations. However, given the lower risk entailed by low voltage lines and the limited number of 66kV lines found in high risk areas, the difference in benefit levels between this alternative and the proposed regulations would, in practice, be small.

7.1.2. Expected costs of the alternative

The costs of this alternative would, in theory, be lower than those of the proposed regulations. The intention of the VBRC in making this specific recommendation was clearly to target its proposed increase

[1] In rare cases they may share with 66kV lines or, more rarely still, with both 22kV and 66kV lines (ie three voltages on one pole).

in inspection requirements and avoid unnecessary cost increases. However, in assessing the comparative costs of this alternative and the proposed regulations, two considerations must be weighed.

First, as indicated above, a relatively small proportion of the above ground electricity assets in high risk areas that would be captured by the proposed regulations are low voltage lines operated by MECs or specified operators or are 66kV lines. This means that the potential cost savings of avoiding increasing inspection frequencies for these assets would be low.

Secondly, it is unlikely, as a matter of practicality, that regulated parties would implement differentiated inspection arrangements for these assets were this alternative to be adopted. One reason for this is that, as indicated above, the low voltage/66kV assets are in many cases co-located (i.e. on the same poles) as the assets that would be subject to three-yearly inspection. Moreover, others that are not co-located are in any case geographically intermingled with the SWER/22kV assets. This means that it is inefficient to inspect the two asset groups on a different cycle.

Particularly in the case of the major distribution businesses, the inspection procedure is well established to make the most efficient use of inspection resources. This includes the sequential inspection of poles on a 'run' that includes all poles in a geographic area based on either feeder or street/road. This is important not only from the inspection perspective, but also creates maintenance synergies and improves customer service by concentrating all work in an area at the same time which minimises lost time and reduces customer supply interruptions for work (although maintenance prioritisation may result in a number of visits over several months, but generally, not years).

The two major distribution companies that would incur up to 90% of the costs of compliance with the proposed regulations both responded to a questionnaire from ESV by stating that their general approach to scheduling inspections would be to seek to schedule this activity in a way that was most efficient having regard to other commercial and managerial requirements. Hence, as discussed above, they expect to adopt a 30 month (2.5 year) inspection cycle, even though the regulations require only a 37 month cycle.

In this context, it is considered unlikely that the adoption of this alternative would yield any substantive reduction in inspection costs compared to the proposed regulations.

7.1.3. Assessment of the alternative

The above analysis indicates that, in practice, the benefits and costs associated with this alternative would be very similar to those of the proposed regulations. While expected benefits would necessarily be smaller, due to the more limited scope of the three-yearly inspection requirement under this alternative, the limited range of assets that would be excluded from the 3 yearly inspection requirement, plus the lower risk levels associated with low voltage lines, suggests that the difference would be small.

Similarly, while cost savings would be expected, their potential magnitude is also small, given the relatively small proportion of assets in question. More importantly, however, the commercial realities surrounding the inspection process imply that even these potential benefits would not be likely to be obtained in practice. The consequence is that this alternative is likely to entail marginally smaller benefits than the proposed regulations, together with costs equal to those of the proposed regulations.

7.2. Alternative 2: Age-adjusted inspection frequency using 2.5 yearly inspection for assets 20 years and older and 5 yearly inspection for younger assets

Within the current context of substantial concern over the role of past inadequacies in inspection performance, it is arguable that the most appropriate variant of a risk-based inspection model would be one that seeks to improve effectiveness, rather than one which seeks to reduce costs. Consequently, the alternative assessed below is based on a combination of a more frequent inspection regime than the proposed regulations for older assets and a less frequent inspection for newer assets. Specifically, all assets that are less than 20 years old would be required to be inspected at five-yearly intervals, while older assets would be required to be inspected at 2.5 yearly intervals. In addition, all concrete poles would be required to be inspected at only five-yearly intervals.

7.2.1. Expected benefits of the alternative

As indicated above, the key benefit of this alternative is that it allows for a potentially more effective targeting of inspection activity. Evidence presented to the VBRC shows that there is a strong correlation between the age of an electricity line and the probability of it failing, particularly when the age of the assets in question exceeds about 40 years. This alternative would imply that fewer resources would be devoted to inspection of younger assets that had a very low probability of being found to be faulty and in danger of failure.

By implication, a larger quantum of resources could thereby be directed toward inspections of older assets characterised by higher fault rates. This implies that faults would be detected earlier, on average, than under the proposed regulations. Based on the intervals suggested above, the maximum time elapsing between inspections of older assets would be seven months, or 19% less than under the proposed regulations. This might mean, in many cases, that a re-inspection would occur prior to an additional bushfire season passing, rather than after it.

Similarly, distribution businesses have chosen, to date, to adopt lower inspection frequencies in relation to concrete poles because of observation of their superior reliability performance. This alternative would enable this approach to be continued, in contrast to the proposed regulations.

7.2.2. Expected costs of the alternative

Given the inspection frequencies proposed above, newer assets would be subject to inspection at intervals almost 40% less frequent than those required under the proposed regulations, as would concrete poles, even where they exceeded 20 years of age. Conversely, older assets would be inspected only 19% more frequently than under the proposed regulations.

The number of inspections required under this alternative, relative to the proposed regulations, cannot be estimated with any certainty, however, due to a lack of detailed data on the age profile of the affected assets and the number of concrete poles. An indicative estimate of the comparative cost implications of this alternative can, however, be derived by reference to a 2005 consultant's report on the asset age profile of Powercor assets, submitted to the VBRC[34]. Based on the data contained in that report, it is estimated that 22% of high voltage overhead lines are less than 20 years of age, while the remaining 78% are at least 20 years old. Given the inspection frequencies required under this alternative, the percentage of assets that would need to be inspected each year to comply with this alternative is:

$$(78\%/2.5) + (22\%/5) = 31.2\% + 4.4\% = 35.6\%$$

By comparison, the percentage that would need to be inspected each year under the proposed regulations is:

$$100\% \times (12/37) = 32.4\%$$

This comparison suggests that this alternative could yield costs that were (35.6 - 32.4)/32.4 = 9.9% higher than those associated with the proposed regulations. Given that these costs have been estimated at \$3.42 million (Scenario A) or \$10.0 million (Scenario B), this implies that the costs of this alternative would be:

$$(\$3.42 \times 1.099) = \$3.76 \text{ million (Scenario A)}$$

or

[34] Exhibit 578 – SKM Powercor and Citipower Age Opex Report – ***Impact of Ageing Assets on Operating Expenses- Final Report*** (February 2005), p 14. It has been assumed that half of the assets identified as being between 15 and 24 years of age in 2010 would be classified as being less than 20 years of age for inspection purposes.

($10.0 x 1.099) = $10.99 million (Scenario B).

That is, this alternative would cost between $0.34 million and $0.99 million more than the proposed regulations.

However, as discussed in Section 5, the questionnaire responses received suggest that the two MECs which account for by far the majority of high-risk assets intend to adopt a 2.5 year inspection cycle in response to the proposed regulations. Thus, there would be no difference between the costs incurred by this group with respect to their older assets under the two alternatives. By contrast, they would incur lower costs with respect to their younger assets under this alternative, inspecting 20% of their sub-20 year aged assets annually under this alternative, rather than 32.4%, as under the proposed regulations.

From the point of view of an asset owner in this position - assuming that the age profile of their assets was as per the above calculations - the total proportion of assets inspected under this alternative of 35.6% (as above) compares with an implicit inspection percentage under the proposed regulations (taking into account the expected use of a 2.5 year inspection cycle) of 40%.

As noted in Section 5, the two MECs with the largest proportion of at risk assets have indicated their intention to adopt a 2.5 year inspection cycle in the context of developing a compliance strategy with the proposed regulations. As these two MECs account for around 90% of the inspection costs estimated in Section 5, it appears that the annual proportion of at risk assets that would be inspected under the proposed regulations is near 40%, compared with 35.6% under this alternative. This implies that this alternative could actually result in costs around 10% lower than under the proposed regulations.

The above analysis indicates that there is some uncertainty as to the relative costs of this alternative and the proposed regulations. While a notional calculation of the extent of works required to achieve compliance under the two alternatives (i.e. in terms of percentage of assets to be inspected) suggests that costs will be almost 10% higher under this alternative, an alternative approach which takes into account the stated intentions of affected parties in relation to compliance with the existing regulations suggests that this alternative could actually be implemented at a 10% *lower* cost.

There is clearly a conceptual issue to be resolved in terms of determining the appropriate cost estimate to be employed. While cost estimates based on the responses to specific consultation with affected parties should *a priori* be preferred, it must be recognised that changes in business practices and processes could mean that the currently indicated approach to implementing the proposed regulations is not ultimately adopted in practice - or is initially adopted but later revised.

In sum, it can be said that the costs of this alternative would be broadly similar to those associated with the proposed regulations, with uncertainty existing as to the direction of any (minor) difference in costs.

7.2.3. Assessment of the alternative

While this alternative is based on logical principles, experience to date indicates that a number of practical difficulties would be associated with it, while the expected benefits, in terms of ensuring similar levels of safety performance at lower cost in terms of asset inspections, are likely to be small or non-existent.

Current asset inspection practices are that poles are not inspected for the first inspection cycle. That is, where a five-year inspection cycle is adopted, a new pole will not be inspected until it reaches ten years of age. Hence, an element of the approach proposed under this alternative is already in place. However, experience shows that the gains from adopting this "exemption" process are small, as the new asset is contiguous with other, older, assets in many or most cases. This means that the inspector is on site, and the only saving is the actual inspection time, amounting to 10-15 minutes at most per pole. Thus, it is only where an entire line has been replaced that the adoption of the longer inspection cycle would lead to substantial savings.

A practical difficulty has also been identified in implementing this alternative in practice. This is that the 'age' of an asset is, in many cases, hard to define. Thus, a cross-arm may frequently be replaced on an old pole. In such circumstances, the question is open as to whether this constitutes a "new" or an "old" asset and, thus, what inspection frequency should be adopted. Even if the view is taken that the asset is "new" in this situation (which may be appropriate given that pole failures are rare, compared to the incidence of fires due to the pole top equipment failing) the question of whether partial replacement of pole-top equipment would be enough to cause an asset to be reclassified as new.

Moreover, while the proposed different inspection cycles for concrete vs. wood poles can be justified on the basis that timber poles are subject to rot, while concrete poles are not, it can be noted that the rate of deterioration of conductors, ties, insulators and other pole-top hardware is unaffected by pole type. Hence, given that most failures relate to pole-top equipment, there is arguably little risk-based rationale for adopting differential inspection frequencies based on pole type.

7.3. Alternative 3: Age-adjusted inspection frequency using a 37 monthly inspection for assets 20 years and older and 5 yearly inspection for younger assets

This alternative would employ a 37 month maximum inspection frequency for electricity assets 20 years and older, in common with the proposed regulations, but would adopt a five yearly inspection frequency for assets younger than 20 years, in common with alternative 1, above.

7.3.1. Expected benefits of the alternative

The benefits of this alternative can be expected to be broadly similar to those of the proposed regulations. As suggested above, around 78% of the electricity assets affected by the proposed regulations are believed to be at least 20 years old. The inspection requirements applicable to these assets would be identical under the proposed regulations and this alternative.

Conversely, inspections for the remaining 22% of assets would occur at five yearly intervals, rather than 37 month intervals as under the proposed regulations. Since inspections would occur almost 40% less frequently, it can be expected a priori that faults would be approximately 40% less likely to be detected prior to an asset failure occurring. However, given the expert evidence cited above to the effect that asset failure rates increase rapidly with asset age for older assets, it can be inferred that only a very small proportion of overall faults detected and remedied as a result of asset inspections relate to assets younger than 20 years. To the extent that this is the case, the reduction in benefits under this alternative, vis-à-vis the proposed regulations, can also be expected to be very small.

However, given the lack of specific quantitative information on the relationship between asset age and fault rates, it is not possible to provide a quantitative estimate of this reduction in benefits.

7.3.2. Expected costs of the alternative

As noted, assets would be inspected on a five-yearly basis, rather than a three yearly basis. The proportion of assets required to be inspected annually under the proposed regulations was estimated above as:

100% x (12/37) = 32.4%

By contrast, the proportion of assets that would need to be inspected annually under this alternative is:

78% x (12/37) + 22 x (1/5) = 25.3% + 4.4% = 29.7%

Thus, the number of inspections to be carried out would be 2.7%/32.4% = 8.3% lower than under the proposed regulations.

As the proposed regulations are expected to entail inspection costs that are equal to $2.1 million (Scenario A) or $7.9 million (Scenario B) higher than at present, it estimated that the inspection costs associated with this alternative will be:

- ($2.1 million x 8.3%) = $174,300 lower than under the proposed regulations under Scenario A and
- ($7.9 million x 8.3%) = $655,700 lower than under the proposed regulations under Scenario B.

As indicated in Section 5.4, the expected total costs incremental costs of the proposed regulations are $3.22 million per annum (Scenario A) or $10.01 million per annum (Scenario B). This implies that the total incremental costs of this alternative are likely to be between $3.05 million per annum and $9.35 million per annum under these two scenarios.

7.3.3. Assessment of the alternative

As noted above, inspection costs are expected to be somewhat lower under this alternative than under the proposed regulations. On the basis of the above calculations, inspection costs would be 8.3% lower and total costs would be $174,300 to $655,700 lower annually than under the proposed regulations. This represents a reduction in incremental costs of $0.5 million to $1.8 million in present value terms over the anticipated three year life of the regulations. In practice, however, the cost reductions vis-à-vis the proposed regulations may be somewhat lower. This will be the case to the extent that there are problems in determining the age of certain assets. Moreover, as suggested above, where younger and older assets are found together (e.g. due to ad hoc past replacements of assets) inspection costs are not likely to be reduced in proportion to the number of inspections being undertaken.

The benefits of this alternative will, logically, necessarily be lower than under the proposed regulations. However, the extent of this reduction in benefits is expected to be small, since only a small proportion of asset faults are expected to occur in assets that are less than 20 years old.

Given the logic of inspection targeting and the fact that there is a high degree of confidence (based on expert testimony to the VBRC and submitted documents) that asset age is well-correlated with fault probability - and is thus a sound basis for targeting activity - it must be assumed that the balance of benefits and costs will be more favourable under this alternative than under the proposed regulations. However, the above suggests that the size of any incremental gain in this regard will be small.

Conversely, it can be noted that this alternative does not fully implement the relevant recommendations of the VBRC and is therefore inconsistent to some degree with the commitments given by all major political parties to implement these recommendations.

7.4. Alternative 4: improve inspection quality without mandating inspection frequency

A third feasible alternative would involve acting to introduce qualifications requirements for inspectors in order to enhance the effectiveness of inspections, while still allowing asset owners to determine their own inspection frequencies. The proposed inspection frequencies would, as is current practice, need to be approved by ESV in the context of the broader BMP submitted for approval under the Act's requirements. This could mean that ESV would administratively require an increase from the current five year inspection cycle in some cases, but an increase in frequency to three years would not be mandated under this alternative.

7.4.1. Expected benefits of the alternative

This alternative would be expected to lead to a substantial reduction in in-service failures of electricity assets. As noted elsewhere, a 1997 report commissioned by Powercor and cited by the VBRC found that if a set of improvements in inspection effectiveness then being foreshadowed were implemented, expected reductions in in-service failures would fall by over 80 per cent from then observed levels. This anticipated reduction was even larger than that modelled with respect to a notional increase in the frequency of inspections from five yearly to three yearly.

These results imply that a very substantial proportion of the benefits of the proposed regulations would be expected to be obtained under this alternative, even though the frequency of inspections would not necessarily increase.

An additional benefit of this alternative is that it would retain a significant aspect of the current arrangements, which is that asset owners are made clearly responsible for determining an overall management strategy for minimising the bushfire risk associated with their assets. That is, it avoids adding a further prescriptive element to the regulations. This can be considered appropriate given the fact that the risk associated with particular assets necessarily with asset age and other characteristics and with the level of risk of the environment in which the assets are located. Providing for a flexible inspection frequency recognises this difference in risk profile.

7.4.2. Expected costs of the alternative

The costs of this alternative can be expected to be somewhat lower than those associated with the proposed regulations. As set out in Section 5, above, the costs of increasing the inspection frequency constitute the majority of the costs associated with the proposed regulations, accounting for $2.1 million of an expected $3.45 million per annum incremental cost in the "low cost" scenario[35].

This implies that, were the same approach to upgrading the effectiveness of inspections to be taken as under the proposed regulations, without any increase in inspection frequency being required, the incremental costs of this alternative would be only $1.35 million.

In practice, the costs associated with this alternative would be likely to be larger than this would suggest, for two reasons. First, in the absence of an increase in inspection costs, the greater reliance on improved inspection effectiveness this implies would be likely to result in a farther-reaching approach to improving effectiveness than that currently proposed being implemented. This could involve, for example, mandating a more rigorous qualification requirement than that currently proposed or mandating some aspects of the inspection process.

Second, while this alternative does not imply any mandated inspection frequency, it remains probable that, in light of the events of Black Saturday, the evidence presented to the VBRC and the recommendation made by the Commission that inspection frequencies be increased, the ESV would in

[35] The "high cost" scenario is not relevant here, as that scenario is predicated on higher inspection frequencies.

practice require more frequent inspection regimes to be adopted, via its process of assessment of draft BMP submitted by asset owners.

7.4.3. Assessment of the alternative

It is clear that this alternative would entail lower costs than those associated with the proposed regulations, since the major cost driver of the proposed regulations would not be present under this alternative. However, as discussed above, the cost reduction involved would be limited by other factors. It is likely, nonetheless, that costs could be as little as half of those incurred under even the low cost scenario presented above with respect to the proposed regulations.

The benefits of this alternative would also be lower than those of the proposed regulations. While increased inspection effectiveness is believed to be able to reduce in-service failure rates substantially, the significantly greater time elapsing between inspections under this alternative - potentially remaining at five years versus 2.5 to 3 years under the proposed regulations - necessarily means that there is greater opportunity for failures to occur.

In addition, this alternative does not respond to VBRC recommendation 28 and is inconsistent with the Government's commitment to adopt and act on all of the Commission's recommendations.

8. Conclusion

8.1. Overview and break-even analysis

The proposed regulations have been assessed as being likely to lead to cost increases for MECs and specified operators totalling between $3.45 million and $10.03 million per annum. The actual costs incurred will depend on decisions that must be made by the regulator (ESV) after draft BMP prepared in compliance with the interim and proposed regulations have been submitted for assessment. These decisions will necessarily involve interpreting the requirements of the regulations in the context of the specific proposed actions contained in the draft BMP. Hence, it is not possible at this stage to determine whether the actual costs incurred will be near the lower or the upper end of the range indicated.

These identified costs represent significant increases in current expenditures in relation to inspections of electrical lines in high bushfire risk areas: it was estimated that current inspection costs are around $8.6 million per annum. Conversely, these cost increases are very small in relation to the turnover of the businesses concerned. The revenue of the two largest distribution businesses alone is of the order of $1.5 billion per annum, while profits exceeded $300 million[36]. That said, it must be acknowledged that while the regulated entities initially bear the cost of the improvements inspection arrangements required by the regulations, it is likely that most of these costs will be passed on to consumers of electricity through the periodic regulated electricity price resetting arrangements.

The expected benefits of the proposal involve reductions in the risk of losses due to bushfires caused by electricity assets. These benefits are expected to be obtained due to substantially improved inspection arrangements allowing for significant improvements in the allocation of maintenance expenditures on electricity lines in high bushfire risk areas; while the major distribution businesses expect some expenditures to be brought forward, they do not anticipate that maintenance expenditure over the medium term will be affected by the changes.

Given the range of uncertainties identified, including future changes to bushfire risk in the context of changing weather patterns, the impact of the ageing of the electricity infrastructure on its contribution to bushfire risk and the effectiveness of improved inspection arrangements in mitigating these risks, it has been necessary to conduct a break-even analysis rather than a formal benefit/cost analysis.

The break-even analysis presented above shows that the regulations will produce net benefits if losses due to bushfires caused by electricity assets are reduced by more than 5.8% (low cost scenario) or 16.7% (high cost scenario).

[36] Derived from the latest Annual Reports for Powercor and SP AusNet.

In assessing the likelihood that this threshold level of benefits will be reached, the size of the expected impact of the regulations on current inspection activity must be considered. With respect to the major electricity distribution businesses with assets in bushfire prone areas, it is anticipated that the current level of inspection activity will be approximately doubled. It can be considered highly likely that such a substantial increase in inspection activity, combined with the expected improvement in inspection quality, deriving from the requirement to use only qualified inspectors, will yield important benefits in terms of the design and implementation of the resulting maintenance programs.

Evidence on this question was presented to the VBRC. The Commission cited a 1997 study of the Powercor network which found that a reduction in the inspection interval from five years to three years would be expected to result in a 70 per cent reduction in in-service failures. The same study found that:

> *"...a substantial improvement in the effectiveness of asset inspection significantly reduces the risk of in-service asset failure. Powercor's analysis shows that, if the improvements in effectiveness foreshadowed in 1997 had been made without extending the inspection cycle, the projected number of in-service failures each year would have reduced from 500 to 84."*[37]

This evidence suggests that each of the two main substantive changes incorporated in the proposed regulations would, in isolation, be expected to reduce in-service failures by more than two thirds. The combination of these measures must be expected to have a still larger impact. Such a major reduction in the incidence of in-service failures must *ipso facto* be expected to result in a substantially reduced risk of bushfire ignition. In turn, the expected extent of bushfire-related costs due to ignition by electricity assets must be expected to be sharply reduced.

It was noted above that, even on the "high cost" scenario, a 16.7% reduction in the costs of bushfire due to electricity assets would fully offset the costs of the proposed regulations. If, by contrast, a 25% reduction in these costs were to be achieved, net benefits averaging around $20 million per annum would be obtained. Even this level of benefit might be considered to be conservative given the size of the expected reductions in in-service failures highlighted in the above report to Powercor.

In this light, it is considered highly likely that the threshold level of benefits will be reached in practice and the proposed regulations will, consequently, yield positive net benefits. It should be noted, in this context, that the major elements of the proposed regulations are consistent with the specific recommendations of the VBRC. These recommendations arose as a response to the significant evidence presented to the Commission that there were numerous instances of inspections failing to uncover asset faults and that inspection frequencies were in often insufficient to allow faults to be reliably rectified before failure occurred. Thus, steps taken to remedy both of these identified concerns can be expected to have substantial performance impacts.

[37] Victorian Bushfire Royal Commission (2010). ***Final Report***. Vol. 2, Ch 4., p 160.

Moreover, in reaching the conclusion that the threshold level of benefits is likely to be attained, it is noted that the level of costs incurred - and hence the specific threshold level of benefits required to be met - is to be determined as part of the process of assessing and approving individual BMP submitted for approval. This implies that the higher level of costs - associated with scenario B - will not be incurred unless ESV is convinced in this context that sufficient additional benefits, in terms of a higher failure detection rate, as to justify such a view being taken from a safety perspective.

A significant risk, in relation to the above, arises from the information received from one major distribution business that stated that there was currently no correlation between the time elapsed since last inspection and the probability of the asset failing. This was presented as evidence that the current inspection arrangements are effective and that no improvements are required. However, even if this conclusion is robust, the ageing of the electricity infrastructure must be taken into account. As noted above, much of that infrastructure is now approaching an age at which failure rates can be expected to increase very rapidly. Within this context, a significant improvement in inspection arrangements is very likely to yield significant benefits over the medium term.

Finally, the break-even analysis, being based on expected values, implicitly regards the population as being risk-neutral in relation to bushfire risk. However, the response to the Black Saturday fires, as documented by the VBRC, strongly suggests that the Victorian population is, in fact, risk averse with respect to bushfire risk. Indeed, the experience of previous major bushfires and the inquiries conducted with respect to them suggests that this risk averse view has existed for some time. This consciousness of a strong community expectation that strong action will be taken to reduce the future risk of catastrophic bushfires underlies the extensive recommendations of the VBRC report, including those that specifically call for the major substantive elements of the proposed regulations to be adopted.

The effect of adopting an assumption of risk aversion here is to reduce the threshold level of benefits that must be met in order to achieve a break-even outcome. That is, a risk averse population will theoretically be willing to spend on reducing the risk of bushfires up to a level that actually exceeds the likely cost of losses due to bushfires. This implies that the break-even level of reduction in bushfire related losses will be lower than the percentages indicated above would suggest. However, in the absence of any specific information on the degree of risk aversion involved, a precise "risk preference adjusted" break-even point cannot be calculated. It can simply be noted that, to the extent that this notional adjusted break-even point is lower than that identified above, the likelihood that the proposed regulations will reduce bushfire related costs to a level that meets this threshold is necessarily increased.

Given the above, it is believed that the proposed regulations are highly likely to yield positive net benefits.

8.2. *Multi-criteria analysis*

As discussed above, it is not possible to compare the proposed regulations and the identified alternatives in fully quantified terms, chiefly because of necessary uncertainty as to both the costs associated with the alternatives and the benefits associated with all three alternatives. Consequently, in accordance with the Victorian Guide to Regulation, a Multi-Criteria Analysis (MCA) has been undertaken. MCA is a tool which allows different alternatives to be assessed simultaneously in terms of multiple criteria. It is particularly widely used where it is not possible to quantify all impacts and/or to express them in dollar terms.

Three criteria have been identified, consistent with the underlying objectives of the proposed regulations. These are:

- The ability of the proposal to reduce bushfire risks arising from electricity asset failure;
- The substantive compliance costs of implementing the proposal; and
- The administrative burdens imposed by the proposal.

Thus, the first, of these criteria relates to the benefits attributable to the various alternatives, while the second and third relate to the costs they would impose. Given that there are two cost criteria and one benefit criterion, it is necessary to weight the criteria in order to provide a balanced assessment. This means that the total weight given to the two cost criteria must equal that of the benefit criterion. Substantive compliance costs are, where quantifiable, generally found to be significantly larger than administrative burdens. Hence, the substantive criterion has been weighted significantly more heavily than the administrative costs criterion.

Consistent with the above considerations, the following weights have been assigned to the criteria:

- Ability to reduce bushfire risks: 1.0
- Substantive compliance costs: 0.8
- Administrative burdens: 0.2

The following discusses the scores accorded to each alternative in relation to each of the criteria. Each alternative is assessed against a base case of the principal regulations continuing in force as they were prior to the adoption of the interim regulations. Scores are allocated against a scale ranging from +5 to -5, with a zero score being equivalent to the situation obtaining in the base case.

Ability to reduce bushfire risks

As discussed above, the proposed regulations are considered likely to be highly effective in improving the timely detection of faults and minimising in-service failures, relative to the current position. They have therefore been allocated a score of +4 against this criterion. Alternative 1, involving applying the maximum inspection frequency requirements only to SWER and 22kV lines, as recommended by the VBRC, has been assessed as marginally less effective in this regard than the proposed regulations. However, given the small size of the expected difference in effectiveness between the two alternatives, it has also been scored at +4.

The alternative of adopting variable inspection frequencies, based on a 2.5 year/5 year inspection schedule has the theoretical potential to yield still greater effectiveness, by focusing inspection effort more closely on older assets likely to be more failure prone. However, as noted above, it is expected that the *actual* inspection frequency for assets over 20 years of age that would be adopted by the major distribution businesses under the proposed regulations would also be 2.5 years, as with the proposed regulations. Thus, the practical difference between the proposed regulations and this alternative would apply only to the small proportion of at risk electricity assets operated by specified operators. Given this, the expected difference in effectiveness, vis-à-vis the proposed regulations is again small. Hence it scores +4.5 on this criterion.

The alternative of adopting variable inspection frequencies based on a 37 month/5 year inspection schedule was assessed as entailing a lower degree of effectiveness than the proposed regulations. However, given the small difference between the two alternatives in this regard, this alternative scores 3.5 points on this criterion.

Alternative 4, of setting minimum qualification requirements for inspectors without specifying a minimum inspection frequency is expected to yield significant effectiveness gains by comparison with the base case, but to be somewhat less effective than the proposed regulations. Consequently, this alternative scores +2 against this criterion.

Substantive Compliance Costs

All three alternatives increase substantive compliance costs when compared with the status quo and therefore receive negative scores. The least costly alternative is that of setting minimum qualifications requirements only. This alternative therefore scores -1. The proposed regulations are likely to be significantly more costly than this alternative, given current asset inspection practices - as noted in Table 5.1, the increased inspection frequency alone is likely to increase inspection costs by between 23.7% (Scenario A) and 90.7% (Scenario B). They therefore score - 3.

The alternative of limiting the application of the minimum inspection frequency requirement to SWER and 22kV lines has been assessed as having virtually identical implications for substantive compliance costs and also scores - 3.

The alternative of adopting variable inspection frequencies based on a 2.5 year/5 year inspection schedule was found to have uncertain cost implications, vis-à-vis the proposed regulations, depending on the framework for comparison adopted[38]. It was clear that any difference in costs between these two alternatives would be small (around 10%), but the direction of the difference is uncertain in practice. Thus, this alternative also scores -3.

The alternative of adopting variable inspection frequencies based on a 37 month/5 year inspection schedule was found to entail inspection costs up to 8.3% lower than those of the proposed regulations and total costs of $0.5 million to $1.8 million lower than the proposed regulations in present value terms over the life of the regulations. This alternative scores -2.5.

Administrative Burden

This criterion focuses on the administrative burdens placed on both regulated parties and on the regulator under each alternative. These burdens constitute the resources required to interpret and apply the requirements of each option in practice. The proposed regulations score highest against this criterion, since both the minimum inspection frequency and the qualifications requirements are established explicitly in the regulations, while the same inspection frequency applies to all at risk assets. The fact that these matters are specified explicitly means that administration of the regulations should be less costly and that there should be greater certainty of outcome than under the current regulations.

From the point of view of regulated parties, there is no requirement to determine an appropriate inspection schedule for the relevant assets, or to determine whether differentiated inspection frequencies should be adopted for different asset types. Such judgements, if required, must be made in the context of the broader set of strategies and mechanisms established under the BMP and must also take account of commercial requirements. Hence, this is potentially a relatively complex task. From the point of view of the regulator, there is similarly no requirement to make judgements about the acceptability of a proposed inspection frequency in the context of the specific BMP proposal and asset profile.

Given these factors, the proposed regulations receive a positive score, assessed as +2. The alternative of setting a maximum inspection frequency only for SWER and 22kV lines receives the same score. While it would theoretically be necessary to operators to identify appropriate inspection frequencies for low voltage and 66kV lines under this alternative, the above discussion indicates that, in practice, they could be expected to adopt the same inspection frequency for all assets.

The alternative of specifying only a minimum qualification requirement is considered to have similar degree of ease of administration to the current arrangements and therefore scores zero.

The alternative of variable inspection frequencies is considered to impose greater administrative difficulties than the previous regulatory requirements, as discussed in section 7. In particular, it

[38] Note: The costs of this alternative will, in common with the proposed regulations, vary substantially according to the view taken by ESV in relation to aerial inspections. However, as suggested here, the relative costs of the two alternatives will vary little under either scenario.

potentially requires verification of the age of a range of assets and raises the issue of the treatment of various assets where partial renewal of the asset has previously occurred (e.g. replacement of pole-top equipment on an existing pole). This difficulty arises with respect to both of the alternatives based on variable inspection frequencies. While regulated parties have made some distinctions between asset types in setting inspection frequencies under current arrangements (e.g. inspecting concrete poles less frequently than wooden poles), it is clear that adopting an alternative based on asset age-based variations in inspection frequencies would be more administratively complex than under these "base case" arrangements. The extent of this increase in complexity is difficult to verify. Hence, this alternative has been given only a small negative score, suggesting a small degree of additional administrative burden. It is considered, however, that this is a conservative approach, given some of the above discussion of the difficulties of judging the ages of some assets that have been partially renewed. Hence, it is possible that this alternative should receive a lower score against this criterion.

Hence, both of the alternatives based on variable inspection frequencies must receive a negative score. Both alternatives have been assessed as scoring - 1.

Table 8.1: Multi-criteria analysis of feasible alternatives

	Proposed regulations	**Limit 3 yr inspection requirement to SWER & 22kV lines**	**Variable inspection frequencies (2.5 yr/5 yr)**	**Variable inspection frequencies (37 month/5 yr)**	**Qualifications regulated only**
Reduction in bushfire risk	+4 x 1 = +4	+4 x 1 = +4	+4.5 x 1 = +4.5	+3.5 x 1 = +3.5	+2 x 1 = +2
Substantive compliance cost	-3 x.8 = -2.4	-3 x.8 = -2.4	-3 x.8 = -2.4	-2.5 x .8 = -2	-1 x .8 = -.8
Administrative burden	+2 x .2 = .4	+2 x .2 = .4	-1 x .2 = -.2	-1 x .2 = -.2	0
Total	**+2.0**	**+2.0**	**+1.9**	**+1.3**	**+1.2**

Table 8.1 shows that the proposed regulations and the alternative of limiting the scope of the maximum inspection frequency requirement jointly receive the highest score of +2.0. The alternative of adopting variable inspection frequencies based on a 2.5 year/5year cycle receives a score only slightly lower, at +1.0. The remaining two alternatives receive significantly lower scores of +1.3 and +1.2 respectively.

This result, in which three alternatives all receive very similar scores, reflects the fact that despite being formally quite distinct, consultation with regulated parties and observation of past practice has demonstrated that the actual response to these three alternatives would be very similar. Thus, for example, the three alternatives were all rated identically in terms of substantive compliance cost, because it is expected that the inspection arrangements that would be adopted in response to each alternative would be essentially identical.

While the proposed regulations and Alternative 1 receive the same score, it has been noted above that the proposed regulations would yield marginally improved risk reduction outcomes by comparison with the proposed regulations, but would have marginally higher compliance costs. Given this and the strong public desire to reduce bushfire risk, this alternative is preferred.

However, a difficulty with respect to the above analysis must be acknowledged. It has been assumed implicitly that, in the absence of regulations explicitly requiring a set 37 month maximum inspection cycle and specified qualifications criteria for inspectors, ESV practice in assessing and approving proposed BMP would be unchanged from the situation that obtained prior to 2009. In practice, this is highly unlikely. The combination of community expectation and the government's commitment to implementing the VBRC recommendations, including those relating to the frequency and quality of asset inspections, implies strongly that, even in the absence of explicit regulatory requirements, there would be significant pressure on ESV to do all that it could within the existing statutory framework to require the affected bodies to implement improved inspection practices. To the extent that changes to current arrangements are considered likely to follow due to these dynamics, it is clear that the above will tend to over-estimate both the benefits and the costs of the proposed regulations.

Given the above, it is proposed to proceed with the proposed regulations.

9. Implementation, monitoring and enforcement

The *Victorian Guide to Regulation*, a guideline made under the authority of the *Subordinate Legislation Act 1994*, requires that Regulatory Impact Statements (RIS) should include a discussion of the means by which proposed regulations will be implemented, evaluated and reviewed over time.

Specifically the Guide requires that the RIS considers what is required to practically implement the proposed regulations, including discussion of any transitional arrangements that may be necessary to minimise the initial impact of the preferred option or to allow time for supporting business systems (e.g. Information Technology systems needed to support registration and licensing systems) to be developed, trailed and tested.

The Guide also requires the RIS to include an explanation of how proposed regulations are to be enforced, including an identification of all the departments and agencies that will have a role in administering and/or enforcing the preferred option.

Implementation

As discussed above, the interim regulations that took effect in October 2010 contain the same substantive provisions as those of the proposed regulations. This means that these requirements have already taken effect. Implementation will occur through the process of annual submission and approval of updated BMP mandated under the *Electricity Safety Act 1998*. No specific implementation arrangements are therefore required in order to give effect to the regulations. The only change to current practice will be that ESV will act to ensure that all modified BMP comply with the provisions of the interim/proposed regulations before approving plans.

Monitoring

Data on the incidence of fire ignitions due to electricity assets is routinely collected. Fire starts are reported immediately to ESV if they are significant. Otherwise all minor fire starts are reported within 20 days and included in summary in industry quarterly statistical reports. Information on reporting arrangements is typically found in the BMP prepared by MECs and Specified Operators. For example, Powercor's 2011 Bushfire Mitigation Plan[39] states:

> *"Reporting on Ground Fires and Pole Fires is done as they occur and reported to ESV. This is carried out in accordance with:*
>
> *Work Instruction 05 - W885 - Pole & Ground Fire Reporting*

[39] Powercor Australia (2011). ***Bushfire Mitigation Strategy Plan 2010-2011***. p 57.

Powercor has an arrangement with the CFA for obtaining monthly attendance figures for all fire starts and pole fires. Powercor's ground fire start information is normalised against the CFA fire start statistics. This information is then be reported to Senior Management and supplied to the ESV annually at the end of the fire danger period."

The number of such ignitions is large: for example, the VBRC noted that:

The number of fire starts involving electricity assets remains unacceptably high—at more than 200 starts recorded each year.[40]

That said, there is considerable variation year-on-year due to variations in meteorological factors such as the amount and frequency of rain and variations in temperature.

The combination of the large number of ignitions occurring annually and the inter-locking reporting and monitoring arrangements noted above means that a sound database is available. However, particularly in light of the year to year variation due to meteorological and other factors, it is likely that any trends will take several years to become apparent.

Asset failure reporting has also been introduced into the new Electricity Safety Management System (ESMS) reporting, and reliable trends in this factor are expected to become visible over the medium term, i.e. around 5 – 10 years.

In sum, continued monitoring of trends in ignitions due to electricity assets and asset failures should enable judgements to be made as to the effectiveness of the proposed regulations over time. That said, the broader policy environment, in which significant actions are being taken to upgrade electricity assets through mechanisms not directly related to enhanced inspection arrangements, means that issues of attribution of any observed reduction in ignitions will necessarily arise.

Compliance and enforcement

ESV carries out annual auditing of those who have BMP obligations under Parts 8 and 10 of the Act. Audits are typically carried in the lead-up to each summer bushfire season.

At present, audits usually comprise a detailed audit of line inspection policies, procedures and in-field practice, together with a general overview of bushfire mitigation activities covered by the regulations and individual bushfire plans and strategies.

In light of the new internal monitoring requirements under the interim and proposed regulations, ESV auditing can also be expected to address how well MECs and specified operators are monitoring the

[40] VBRC (2010). ***Final Report.*** Vol 2, p 149.

implementation of their BMP and the effectiveness of their inspections and of processes to rectify any deficiencies that may be identified.

Sanctions

Section 83BB of the *Electricity Safety Act 1998* provides that specified operators must not operate an at-risk electric line unless a bushfire mitigation plan that applies to the operator's at-risk electric lines has been accepted or provisionally accepted by ESV. Moreover, the specified operator must comply with an accepted bushfire mitigation plan. Penalties for failure to comply with these provisions are established at 300 penalty units for individuals and 1500 penalty units for bodies corporate. Section 98 of the Act makes similar provisions with respect to MECs.

10. Evaluation strategy

An important feature of best practice regulation is that it is reviewed regularly to ensure that it still represents the most appropriate means of meeting the specified objectives. In order to monitor the effectiveness of the preferred regulatory option, an evaluation or review strategy is required. The Guide requires that the RIS includes information on the proposed evaluation or review strategy.

As discussed above, the proposed regulations will amend the principal regulations, the *Electricity Safety (Bushfire Mitigation) Regulations 2003.* These regulations will sunset in 2013 as a result of the operation of the Subordinate Legislation Act 1994. This implies that a further RIS process will need to be undertaken in relation to the replacement regulations adopted at that time. This means that evidence of the improved effectiveness of the currently proposed amendments will need to be provided in that RIS context.

As well as information obtained from annual auditing, ESV receives data from MECs and fire authorities relating to serious electrical incidents, including those involving supply networks. Analysis of this data will help ESV to identify emerging trends in incidents and, over time, may shed light on the effectiveness of the enhanced inspection regime required under the interim and proposed regulations.

11. Regulatory Change Measurement Assessment

Under the Victorian government's revised Reducing the Regulatory Burden Initiative, announced in 2009[41], material changes in regulatory costs imposed on business, the not-for-profit sector, the operation of government services and some costs incurred by private individuals by new or amended regulation must be assessed through the preparation of two separate documents: a Business Impact Assessment or Regulatory Impact Statement and a Regulatory Change Measurement. Both documents are required to assess all regulatory costs - i.e. administrative burdens, substantive compliance costs and delay costs. However, while the BIA/RIS requires a benefit/cost analysis to be completed and a range of alternative policy options to be assessed, the RCM simply requires changes in regulatory costs to be measured.

Moreover, a specific methodology is required to be employed in the RCM. This differs from that used in BIA/RIS in some ways. Notably, it provides a greater emphasis on the incidence of the identified costs, highlights the issue of delay costs and, importantly, is based on the measurement of cost changes in *annual* terms, rather than the calculation of costs on a present value basis over the expected life of the regulations.

An RCM report must be employed where there is prima facie evidence that changes in regulatory costs are likely to be material. A regulatory cost change is material if:

- The change in administrative burden experienced by the affected sector is greater than $250,000 per annum; or
- The change in the sum of compliance costs (including administrative and substantive compliance costs) and costs of delays, experienced by the affected population, is greater than $500,000 per annum.

Changes in administrative burdens

As discussed, the proposed regulations will be implemented via the existing administrative processes in relation to the submission and approval of BMP. It is not anticipated that the adoption of a specified inspection frequency or a requirement for inspectors to possess minimum qualifications will materially change the administrative burdens associated with this process.

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[41] The revised RRBI was announced in the context of the Treasurer's 2008-09 Progress Report on the Reducing the Regulatory Burden (RRB) initiative, available at www.dtf.vic.gov.au/betterregulation. The new requirements are set out in the *Victorian Regulatory Change Measurement Manual.* Department of Treasury and Finance, effective 1 January 2010. See: http://www.treasury.vic.gov.au/CA25713E0002EF43/WebObj/VictorianRegulatoryChangeMeasurementManual/$File/Victorian%20Regulatory%20Change%20Measurement%20Manual.pdf .

Total regulatory costs

As noted above, an RCM is also required if the sum of all changes in regulatory costs exceeds $500,000 per annum. As indicated in Section 5, above, the expected change in total regulatory costs exceeds this threshold. Hence, a RCM report will be required. This report has yet to be finalised and will be completed separately from this RIS. It is anticipated that the RCM report will be completed within six months of the publication of this RIS.

12. Consultation

The consultation process conducted to date in connection with the proposed regulations has been largely focused on the development and administration of the questionnaire discussed in this RIS. The questionnaire was distributed to all affected firms (both MECs and specified operators) identified by ESV. This means that all affected parties have been given the opportunity to highlight the expected cost impact of the proposed regulations on their businesses and to comment on other relevant issues, including the expected benefits associated with the proposals.

A high response rate was achieved, with written responses being obtained from all electricity distribution businesses and 50% of the identified specified operators. This suggests that the cost estimates derived above can be considered relatively robust. It also indicates that the majority of affected parties have had the opportunity to make their views on the proposed regulations known to the regulator.

In addition to the cost data requested, and provided in summary form in Section 5, respondents were asked to identify what benefits they expected to be derived as a result of the implementation of the proposed regulations. Two distribution businesses stated that they believed that improved training for inspectors may yield safety benefits. A third noted that they had achieved substantial improvements in unplanned outage rates due to their voluntary response to the VBRC recommendations and believed that a further improvement was likely as a result of the adoption of the proposed regulations. However, a fourth argued that their analysis had found no correlation between time since asset inspections and probability of asset failure under current regimes. Under these circumstances, they did not expect any safety benefits to arise. Specified operators similarly did not identify any expected benefits due to the adoption of the proposed regulations.

Given that the interim regulations have been in place since October 2010, stakeholders have a high level of awareness of the content of the proposed regulations. ESV notes that no concerns regarding these regulations have been raised by stakeholders, other than those relating to the need to recover the costs involved. That is, some distribution companies argued that, particularly if scenario B unfolds in practice, there may be a need to apply for a specific "pass through" of these costs under the regulated price-setting mechanisms.

The release of this RIS for public consultation constitutes the remaining stage in the consultation process for these regulations. Comments on the RIS will be received for 28 days.

13. Statement of compliance with National Competition Policy

The National Competition Policy Agreements ("NCPA") set out specific requirements with regard to all new legislation adopted by jurisdictions that are party to the agreements. Clause 5(1) of the Competition Principles Agreement sets out the basic principle that must be applied to both existing legislation, under the legislative review process, and to proposed legislation:

> *The guiding principle is that legislation (including Acts, enactments, Ordinances or Regulations) should not restrict competition unless it can be demonstrated that:*
>
> *(a) The benefits of the restriction to the community as a whole outweigh the costs; and*
> *(b) The objectives of the regulation can only be achieved by restricting competition.*

Clause 5(5) provides a specific obligation on parties to the agreement with regard to newly proposed legislation:

> *Each party will require proposals for new legislation that restricts competition to be accompanied by evidence that the restriction is consistent with the principle set out in sub-clause (1).*[42]

Accordingly, every regulatory impact statement must include a section providing evidence that the proposed regulatory instrument is consistent with these NCP obligations. The recently released OECD Competition Assessment Toolkit[43] provides a checklist for identifying potentially significant negative impact on competition in the RIA context. This is based on the following three questions:

- Does the proposed regulation limit the number or range of suppliers?
- Does the proposed regulation limit the ability of suppliers to compete?
- Does the proposed regulation limit the incentives for suppliers to compete vigorously?

According to the OECD, if all three of these questions can be answered in the negative, it is unlikely that the proposed regulations will have any significant negative impact on competition.

It must be noted that the context for this assessment is one in which the MECs are, in effect, natural monopolies. However, within this context, it can be noted that the proposed regulations do not act directly in any of the above ways. Therefore, it can be concluded that they are unlikely to have any significant negative impact on competition.

In sum, it has been concluded that the proposed regulations are fully compliant with the requirements of the National Competition Policy.

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[42] Clause 5, Competition Principles Agreement, 11 April 1995 accessed at www.ncc.gov.au/pdf/PIAg-001.pdf
[43] See *Integrating Competition Assessment into Regulatory Impact Analysis.* OECD, Paris, 2007. (DAF/COMP(2007)8).

Appendix 1: Proposed Electricity Safety Amendment (Bushfire Mitigation) Regulations 2011

Electricity Safety Amendment (Bushfire Mitigation) Regulations

Exposure Draft

TABLE OF PROPOSALS

Victoria

Electricity Safety Amendment (Bushfire Mitigation) Regulations

Exposure Draft

1 Objective

The objective of these Regulations is to amend the Electricity Safety (Bushfire Mitigation) Regulations 2003 to—

(a) prescribe further particulars to be included in a bushfire mitigation plan; and

(b) make miscellaneous and consequential amendments as a result of the enactment of the **Energy and Resources Legislation Amendment Act 2010**, which makes further provision relating to bushfire mitigation plans.

2 Authorising provisions

These Regulations are made under sections 151A and 157 of the **Electricity Safety Act 1998**.

3 Commencement

These Regulations come into operation on 13 October 2011.

4 Revocation

The Electricity Safety (Bushfire Mitigation) Amendment Interim Regulations 2010[1] are **revoked**.

5 Principal Regulations

In these Regulations, the Electricity Safety (Bushfire Mitigation) Regulations 2003[2] are called the Principal Regulations.

6 Objective substituted

For regulation 1 of the Principal Regulations **substitute—**

"**1 Objective**

The objective of these Regulations is to make provision for the preparation of bushfire mitigation plans by specified operators and major electricity companies and for the inspection of private overhead electric lines by certain major electricity companies.".

7 Regulations 5 and 5A substituted

For regulations 5 and 5A of the Principal Regulations **substitute—**

"**5 Prescribed particulars for bushfire mitigation plans—specified operators**

For the purposes of section 83BA of the Act, a bushfire mitigation plan submitted by a specified operator must specify—

(a) the name, address and telephone number of the specified operator;

(b) the name, position, address and telephone number of the person who was responsible for the preparation of the plan;

(c) the name, position, address and telephone number of the persons who are responsible for carrying out the plan;

(d) the telephone number of a person who can be contacted in an emergency that requires action by the specified operator to mitigate the danger of bushfire;

(e) the bushfire mitigation policy of the specified operator to minimise the risk of fire ignition from its at-risk electric lines;

(f) the objectives of the plan to achieve the mitigation of bushfire danger;

(g) a description, map or plan of the land to which the bushfire mitigation plan applies, identifying all hazardous bushfire risk areas and the location of all the specified operator's at-risk electric lines in those areas;

(h) the preventative strategies to be adopted by the specified operator to minimise the risk of the specified operator's at-risk electric lines starting fires;

(i) a list of all works required for the strategies referred to in paragraph (h) to be undertaken and the date by which the works are to be completed;

(j) a plan for inspection that ensures that all of the specified operator's at-risk electric lines are inspected at regular intervals of no longer than 37 months;

(k) details of the processes and procedures for ensuring that only persons who have satisfactorily completed a training course approved by Energy Safe Victoria are assigned to carry out the inspections referred to in paragraph (j);

(l) the operation and maintenance plans for the specified operator's at-risk electric lines—

(i) in the event of a fire; and

(ii) during any day that has been declared to be a day of total fire ban under the **Country Fire Authority Act 1958**; and

(iii) during a fire danger period;

(m) the investigations, analysis and methodology to be adopted by the specified operator for the prevention of fire ignition from its at-risk electric lines;

(n) details of the processes and procedures by which the specified operator will—

(i) monitor and audit the implementation of the bushfire mitigation plan;

(ii) identify any deficiencies in the plan or the plan's implementation;

(iii) monitor and audit the effectiveness of inspections carried out under the plan;

(iv) improve the plan and the plan's implementation if any deficiencies are identified under subparagraph (ii);

(v) ensure that any training necessary for persons assigned to perform functions under the plan is provided;

(vi) monitor and audit the competence of the persons assigned to carry out inspections under the plan;

(o) the policy of the specified operator in relation to the assistance to be provided to fire control authorities in the investigation of fires near the specified operator's at-risk electric lines.

5A Prescribed particulars for bushfire mitigation plans—major electricity companies

For the purposes of section 113A of the Act, a bushfire mitigation plan submitted by a major electricity company must specify—

(a) the name, address and telephone number of the major electricity company;

(b) the name, position, address and telephone number of the person who was responsible for the preparation of the plan;

(c) the name, position, address and telephone number of the persons who are responsible for carrying out the plan;

(d) the telephone number of a person who can be contacted in an emergency that requires action by the major electricity company to mitigate the danger of bushfire;

(e) the bushfire mitigation policy of the major electricity company to minimise the risk of fire ignition from its at-risk supply networks;

(f) the objectives of the plan to achieve the mitigation of bushfire danger;

(g) a description, map or plan of the land to which the bushfire mitigation plan applies, identifying all hazardous bushfire risk areas and the location of all the major electricity company's at-risk supply networks in those areas;

(h) the preventative strategies to be adopted by the major electricity company to minimise the risk of the major electricity company's at-risk supply networks starting fires;

(i) a list of all works required for the strategies referred to in paragraph (h) to be undertaken and the date by which the works are to be completed;

(j) a plan for inspection that ensures that all of the major electricity company's at-risk supply networks are inspected at regular intervals of no longer than 37 months;

(k) details of the processes and procedures for ensuring that only persons who have satisfactorily completed a training course approved by Energy Safe Victoria are assigned to carry out the inspections referred to in paragraph (j);

(l) the operation and maintenance plans for the major electricity company's at-risk supply networks—

(i) in the event of a fire; and

(ii) during any day that has been declared to be a day of total fire ban under the **Country Fire Authority Act 1958**; and

(iii) during a fire danger period;

(m) the investigations, analysis and methodology to be adopted by the major electricity company for the prevention of fire ignition from its at-risk supply networks;

(n) details of the processes and procedures by which the major electricity company will—

(i) monitor and audit the implementation of the bushfire mitigation plan;

(ii) identify any deficiencies in the plan or the plan's implementation;

(iii) monitor and audit the effectiveness of inspections carried out under the plan;

(iv) improve the plan and the plan's implementation if any deficiencies are identified under subparagraph (ii);

(v) ensure that any training necessary for persons assigned to perform functions under the plan is provided;

(vi) monitor and audit the competence of the persons assigned to carry out inspections under the plan;

(o) the policy of the major electricity company in relation to the assistance to be provided to fire control authorities in the investigation of fires near the major electricity company's at-risk supply networks;

(p) details of processes and procedures for enhancing public awareness of—

(i) the responsibilities of the owners of private overhead electric lines in relation to mitigation of bushfire danger; and

(ii) the obligation of the major electricity company to inspect private overhead electric lines within its distribution area.".

8 Regulation 6 substituted

For regulation 6 of the Principal Regulations **substitute—**

"**6 Prescribed parts of electric lines excluded**

For the purposes of section 113F(1) of the Act, the prescribed part of a private electric line is the part of the private electric line above the surface of land that is installed after the point at which the line is connected to a building or other structure (not including a pole) on the land.".

9 Regulation 7 substituted

For regulation 7 of the Principal Regulations **substitute—**

"**7 Prescribed times of inspection**

For the purposes of section 113F(1) of the Act, the prescribed times to cause an inspection of private electric lines to be carried out are no later than 37 months after the date of the previous inspection carried out by the major electricity company.".

10 Prescribed standards of inspection

(1) For regulation 8(1) of the Principal Regulations **substitute—**

"(1) For the purposes of section 113F(1) of the Act, the prescribed standards for the inspection of a private electric line that is above the surface of land are—

(a) insulators are free from damage and are properly secured to the pole or cross-arm;

(b) the conductors and metal ties that secure the conductors to the pole are free from rust and in good condition;

(c) insulation is not frayed or broken at any point;

(d) poles are as vertical as practicable and must not lean more than 10 degrees from the perpendicular;

(e) in the case of wooden poles—

(i) the girth of the pole is greater than 550 mm at any point within 200 mm above the ground;

(ii) the pole is free from termites to a depth of 300 mm below the surface of the ground;

(iii) an annulus of at least 50 mm of the wood is free of decay;

(f) in the case of tubular and solid steel poles, the thickness of the metal of the pole in any corroded area below the ground is at least 75% of the sound metal above the ground;

(g) in the case of concrete poles, the pole—

(i) is free of concrete decay; and

(ii) does not have exposed metal reinforcement;

(h) the line complies with Part 2 of the Code;

(i) the line complies with the clearance requirements set out in Table 3.8 of the Australian /New Zealand Wiring Rules: AS/NZS 3000 as published or amended from time to time.".

(2) In regulation 8(2) of the Principal Regulations, for "and (iv) do" **substitute** "does".

11 Regulation 9 substituted

For regulation 9 of the Principal Regulations **substitute—**

"9 Prescribed period in which notice of inspection is to be given

For the purposes of section 113F(2) of the Act, the prescribed period within which notice to the occupier of the land is to be given before inspection of a private electric line is carried out is the period that is not more than 45 days before the inspection and not less than 21 days before the inspection.".

12 Regulation 10 substituted

For regulation 10 of the Principal Regulations **substitute—**

"10 Prescribed form of notice to be given before inspection

For the purposes of section 113F(2) of the Act, the prescribed form of notice to be given to the occupier of the land before inspection of a private electric line is set out in the Schedule.".

13 Regulation 11 substituted

For regulation 11 of the Principal Regulations **substitute—**

"11 Exemptions

Energy Safe Victoria may exempt a specified operator or major electricity company from any of the requirements of these Regulations, subject to any conditions specified by Energy Safe Victoria.".

14 Substitution of Schedule

For the Schedule to the Principal Regulations **substitute—**

"SCHEDULE

NOTICE OF INSPECTION

To the Occupier,

In accordance with section 113F of the **Electricity Safety Act 1998**, please be advised that on or about [*insert date*] our asset inspector will inspect all private electric lines above the surface of land on the property you occupy, except for those parts of the lines that are installed after the point at which they are connected to a building or other structure (not including a pole).

The inspection may reveal that defects exist and maintenance is required on a private electric line on the property that you occupy. If this is the case, we will give the owner written notice of the maintenance work required to be carried out.

Please contact [*insert name of responsible person*] on [*insert telephone number*] if you have any queries.

Signed

[*insert name of major electricity company*]

----------------------------------".

ENDNOTES

[1] Reg. 4: S.R. No. 111/2010.

[2] Reg. 5: S.R. No. 72/2003 as amended by S.R. No. 111/2010.

Table of Applied, Adopted or Incorporated Matter

The following table of applied, adopted or incorporated matter is included in accordance with the requirements of regulation 5 of the Subordinate Legislation Regulations 2004.

In this table, ***Principal Regulations*** means the Electricity Safety (Bushfire Mitigation) Regulations 2003.

Statutory rule provision	**Title of applied, adopted or incorporated document**	**Matter in applied, adopted or incorporated document**
Regulation 10(1) which substitutes regulation 8(1) of the Principal Regulations	Australian/New Zealand Standard, 'Electrical installations', AS/NZS 3000 published 12 November 2007 by Standards Australia	Table 3.8

Appendix 2: Asset Owner Questionnaire

Cost impact questionnaire

Proposed Electricity Safety (Bushfire Mitigation) Amendment Regulations 2011

The Electricity Safety (Bushfire Mitigation)(Amendment)(Interim) Regulations 2010[44] became effective in October 2010 and made a limited number of changes to the existing Electricity Safety (Bushfire Mitigation) Regulations 2003. The major changes were:

- that aboveground electricity assets ***in hazardous bushfire risk areas*** will now be required to be inspected at intervals of no more than 37 months, whereas the required inspection frequency for assets other than Private Overhead Electrical Lines (POEL) were not previously specified; and
- that these inspections will need to be conducted by persons who hold qualifications approved by ESV.

These changes were made in response to recommendations of the Victorian Bushfires Royal Commission that inspection of these electricity assets should be undertaken more frequently than has occurred in recent years and that the inspection process should be made more effective. The interim regulations were adopted as an urgent response to the Royal Commission Report and, as a result, have only a 12- month lifespan. ESV is currently in the process of remaking these regulations, so that their lifespan will be the same as that of the principal regulations, which expire on 24 June 2013.

As part of this process a Regulatory Impact Statement (RIS) is being prepared. RIS are required to include benefit/cost analyses of the proposed regulations and identify feasible alternative means of achieving the regulatory objective. We seek your assistance in completing the following questionnaire as an input to this process. The questionnaire seeks your estimates of the costs involved in complying with the new inspection requirements, together with any other aspects of the interim regulations that impose a significant cost on your business. Consistent with the requirements of the RIS process, we are seeking to understand the extent to which the need to comply with the new requirements will increase pre-existing inspection-related costs. The questionnaire therefore asks you to identify both the costs your business incurred prior to the interim regulations being passed and the costs you expect to occur under the new inspection requirements.

We will also be undertaking a series of interviews with affected businesses, which may be telephone-based or face-to-face in nature. We request that you provide a draft response to this questionnaire in advance of these interviews, but will provide an opportunity for a modified questionnaire response to be submitted following the interviews should this be necessary.

[44] Available at:
http://www.legislation.vic.gov.au/Domino/Web_Notes/LDMS/PubStatbook.nsf/93eb987ebadd283dca256e92000e4069/0D138A3A0CE135B8CA2577C10019EBE4/$FILE/10-111sr.pdf

Jaguar Consulting has been contracted by ESV to complete the questionnaire and interview processes and draft the required RIS. Should you have any questions in relation to the questionnaire, please contact Rex Deighton Smith of Jaguar Consulting (ph 03 9500 0212, m: 0402 129 121 e: jaguar2@tpg.com.au.)

Cost Impact Questionnaire

1. Cost of previous inspection regime

1a. Please indicate the inspection frequency for at-risk overhead lines set out in your Bushfire Mitigation Plan/Asset Management Plan[45] prior to the adoption of the Interim regulations.

1b. Please indicate the average annual cost incurred by your business in implementing these inspection arrangements for at-risk lines. Please provide a breakdown of the major components of these costs, if possible. Please indicate the quantity of inspection activity undertaken (i.e. what quantum of assets are inspected annually).

1c. Please indicate whether inspection costs typically vary from year to year or are approximately constant. Where variation exists, please indicate what factors lead to this.

1d. Please indicate whether inspection activity is undertaken by your organisation or is contracted to third parties.

1e. Please comment on how these costs differ from those that your business would incur in the absence of any specific regulatory requirements in respect of bushfire mitigation plans.

2. *Cost of complying with the new inspection requirements*

2a. Please indicate your expected inspection costs under the modified requirements introduced in the interim regulations. Please estimate costs for each of the next four years - i.e. 2010-11, 2011-12, 2012-13 and 2013-14.

[45] Or generally adopted with respect to your at-risk overhead lines.

2b. Please indicate:

- When your company will commence (or has commenced) additional/modified inspection activity to achieve compliance with the interim regulations.

- When you expect to achieve full compliance with the interim regulations (i.e. all at-risk lines inspected within the last 37 months).

- What additional costs you expect to incur due to the need to inspect assets at 37 month intervals, rather than the current 5 yearly intervals.

- What additional costs you expect to incur due to the need to ensure inspections are carried out by persons with qualifications approved by ESV[46].

2c. Please indicate whether the cost per inspection is expected to change relative to the current position and, if so, by how much.

2d. Please indicate whether you believe that your company would have adopted any changes to its existing inspection practices with regard to at-risk lines following the Black Saturday bushfires, in the absence of any regulatory change. Please indicate what you believe the substance of such changes would have been.

3. Cost of additional monitoring and review requirements

3a. New regulations 5(n) and 5A(n), which were inserted by Regulation 7 of the interim regulations, require major electricity companies and other affected companies to detail the processes and procedures by which they will monitor the implementation of their bushfire mitigation plan and identify any deficiencies. It also requires the effectiveness of the inspection program to be monitored and processes for improving the plan and its implementation in response to any identified deficiencies to be

[46] It is expected that the Certificate II in Asset Inspection, which has been accredited, will be approved by ESV. Please contact Mr Phil Walters on pwalters@esv.vic.gov.au if you do not have access to a copy of the accreditation document.

set out. This includes processes to ensure necessary training is provided to inspection staff and to ensure their competence is monitored.
These requirements replace the former Regulation 5(m), which required:

> *a description of the measures to be used to assess the performance of the electricity supplier under the plan*"

to be provided.
Please outline what steps your company expects to take in order to comply with the expanded requirement. Please estimate what additional costs you expect to incur in complying with this requirement

4. Other direct cost impacts

Please identify any other changes to the principal regulations introduced in the interim regulations which you believe will have appreciable cost impacts on your business. In each case, please estimate these expected costs.

5. Indirect cost impacts

Please indicate what impact the changes to inspection requirements contained in the interim (and the proposed) regulations are expected to have on maintenance costs over time. Please provide quantitative estimates of these cost changes where possible.

6. Expected benefits

Please identify any benefits to your business (other than those directly related to reduced likelihood of bushfire ignition) due to the regulatory changes discussed above. For example, do you anticipate improvements in supply reliability as a result? Please quantify these expected benefits as far as possible.

7. Contact details

Please provide contact details for an appropriate person for us to contact to conduct a follow-up interview.