2021-2026 Victorian Electricity Distribution Price Reset

Summary of engagement with distributors

May 2020

Brotherhood of St Laurence
Working for an Australia free of poverty

1 Introduction

The project undertook engagement with distributors through 2019, with a key focus on their community engagement programs. The results of this engagement have informed the Report on Consumer Engagement, submitted as a deliverable for this Milestone.

The engagement included in Table 1 was conducted between 31 January 2020, with the release of the proposals from the distributors, and 3 June 2020, when submissions are due.

Network businesses were generous in accommodating our questions and making time to talk through them – especially considering the pressures of COVID-19

2 Summary of engagement

Table 1 - Summary of engagement with Victorian Distributors

Engagement	Attendees	Summary of engagement
31 March 2020 Jemena 2021-2026 Proposal	Matthew Serpell, Manager Asset Regulation & Strategy, Jemena Ashley Lloyd, Grid Transformation Manager Dean Lombard, Senior Energy Analyst, Renew Emma Chessell, Project Manager, BSL	Jemena met online to talk through questions provided in advance, at our request. Questions are attached in Appendix 1
3 April 2020 EDPR Proposal Engagement Discussion with AusNet Services	Catherine Gip, Customer Engagement Manager, AusNet Thomas Hallam, General Manager, Regulation & Network Strategy, Ausnet Ian McNicol, Principal Economist, Ausnet Charlotte Eddy, Manager Economic Regulation, Ausnet Emma Chessell Project Manager, BSL	AusNet agreed to meet online at our request, in response to a list of questions sent through via email. Questions and written responses are attached in Appendix 2.
17 April 2020 Written answers to questions emailed about the CPPALUE proposal.	Frans Jungerth, Regulatory Manager, Powercor	CPPALUE networks returned written answers to questions sent through by the project.

Engagement	Attendees	Summary of engagement
12 May 2020 Discussion following the AER Public Forum	Sonja Lekovic, Senior Regulatory Economist Brent Cleeve, Head of Regulation, Powercor Frans Jungerth, Regulatory Manager, Powercor Jeff Anderson, Regulatory Manager, Powercor Emma Chessell, BSL	CPPALUE networks approached us to talk through their response to the AER Issues Paper, as well as questions raised by the project through the Public Forum

3 Appendix 1 – Questions discussed with Jemena

Table 2 – Questions discussed with Jemena

Opex	Are the productivity improvements from the 2019 Transformation Program evident in 2020? Had there been consideration of passing on those cost savings into the upcoming period – eg through a negative step change?
Augex DER and Future network	Jemena's solution combines dynamic voltage control, dynamic export limits, dynamic phase connection, and network augmentation. We are interested in understanding more about the planning decisions for the augmentation component in particular. As solar penetration rises on a part of the network, past the nominated threshold for constraint (eg 30%), what is the planned roll out for these different solutions, ie, will dynamic control be instituted first, and then finally network augmentation? Is the main purpose of network augmentation to reduce the amount of time that dynamic constraints will be imposed, as penetration rises?
	If dynamic controls are used, without network augmentation (on a typical line,) can you give an indication of how often dynamic constraints will be imposed, as penetration increases (from 30 – eg 70%?) For example, will dynamic controls mostly apply just for a few hours around midday on mild summer days? Or should they be expected all year. What is your current pattern for seeing problems caused by solar exports, and how do you expect this to change as solar penetration rises?
	How will dynamic export limits be implemented – is this via signal to compatible inverters? Will inverter upgrades be required for older inverters?
	Are you also able to supply any details of where the augmentation is planned, and when it will be rolled out, on different feeders/zsss.
	Also, whether there was a consideration of non-network options for this problem – especially for zone substations that are facing augmentation for evening peaks (the

	Preston East Rit-D considered battery storage in passing as a non-network solution for this growth – how would the economics change if battery storage was also used to resolve export issues?
	Value of solar – keen to talk more about your justification for using the FIT as the way to value solar?
Relocating assets	As peak load falls in some parts of the network, and rises in others, the suggestion has come up that it might be possible to relocate and reuse some assets. Is this something that Jemena ever does? Are there types of asset for which this might be possible?
IT Capex	What IT upgrades are required for the 5 minute settlement?
Repex	The 2018 EPA Amendment includes some new laws around noise that some distributors have considered to be relevant to their ZSSs. Did you consider these laws in relation to your assets, and do you think any of your zone substations are non-compliant with the new noise laws?
Wooden poles	Is there a difference between the condition assessment, and replacement program for urban and rural areas?
Forecasts	The forecasted cost reductions for customers in the Jemena network depend on the population forecasts for Jemena's growth areas (without customer growth prices are more or less flat). Any idea yet, of how that might be impacted by a possible economic downturn and reduced housing development?

4 Appendix 2 – Questions and written answers provided by AusNet Services

Table 3 – AusNet Services questions and written answers

Opex	**Q1: What is the reason for the higher opex in 2018 (base year for next period) compared to 2019?**	A1: We are indifferent to what base year is chosen. When we started our negotiations with the Customer Forum we used 2018 as 2019 information was not yet available, and we continued with this approach to ensure a stable basis for comparison. With respect to opex in 2019, we note that we do expect a slight increase 2019. There are a range of factors driving this, most notably, an increase in costs due to increased GSL payments (due to weather conditions).
	Q2: What is the planned expenditure for the innovation fund?	A2: We proposed $7.5 million for innovation, of which $1.2 million was opex. This expenditure relates to conducting trials, which may lead to future capital projects. Low voltage projects: • Supporting network voltages with new technologies ($0.2m)

		• Maximising the benefits of solar for commercial customers ($0.3m) DER project • Testing the decentralized power system of the future ($0.7m)
Augex **DER and Future network**	**Q3: Are active dynamic export controls – eg control via a signal, not just allowing inverters to shut off – going to be part of the solution for domestic and/or C&I customers?**	A3: Yes, we expect that dynamic export limit options will be available in the first half of the forth coming regulatory period.
	Q4: If not, is this primarily because this solution has not been developed yet? How far (in terms of years) would you say you were, to implementing this type of dynamic export control at the customer level.	A4: We are currently collaborating with SAPN on an ARENA proposal to develop and test the dynamic export limit approach. If approved, this project would run from 2020 to 2022.
	Q5: As solar penetration rises on a part of the network, past the nominated threshold for constraint (eg 30%), what is the planned roll out for these different solutions, ie, will dynamic control be instituted first, and then finally network augmentation?	A5: It is not necessarily the case that flexible exports will be implemented first. In general: • flexible exports are more likely to be economic in areas with lower customer density; and • augmentation is likely to be more economic in areas of higher customer density. We are not proposing a network wide roll-out of dynamic control in this regulatory period. Rather, we have proposed a more limited roll-out of dynamic control focused on areas of the network where other network augmentation options are not feasible. As solar penetration increases, the exports of these systems are likely to be limited by the voltage. In our proposal we have not nominated a threshold level of solar penetration for constraints as the level of constraints will depend on the network hierarchy and design and not only on the level of solar penetration.
	Q6: Is the main purpose of network augmentation to reduce the amount of time that dynamic constraints will be imposed, as penetration rises?	A6: The main purpose of network augmentation is to enable additional solar export where it is economic to do so. Both static and dynamic constraints reduce the amount of exports, which has a real cost to those customers, but also the wider network users who benefit from cheaper electricity production. For example, evidence is indicating DER has been driving wholesale electricity prices down in South Australia.

	Q7: If dynamic controls are used, without network augmentation (on a typical line) can you give an indication of how often dynamic constraints will be imposed, as penetration increases (from 30 – eg 70%?)	Q7: Once a sufficiently high penetration is achieved at a site then dynamic constraints could be applied for nearly the entirety of the generation period across all seasons. However, that would assume: 1. we do not augment to add additional capacity; and 2. we keep connecting additional generation even once significant constraints have emerged. As more solar joins the severity of the constraint on each generator would increase (limiting their generation by a greater amount). However, our recent Network renewal trial shows how we may be able to use behind the meter technology to manage voltage issues.
	Q8: Will dynamic controls mostly apply just for a few hours around midday on mild summer days? Or should they be expected all year. What is your current pattern for seeing problems caused by solar exports, and how do you expect this to change as solar penetration rises?	A8: In practice, we would expect to see dynamic constraints for a small proportion of the time, when local load is very low and generation is very high. Conversely, there will be times when export limits can be raised, such as when network voltages are low, or local loads are high. It is not possible to quantify exactly the proportion of time that dynamic constraints will be imposed, as this is an area of current investigation.
	Q9: How will dynamic export limits be implemented – is this via signal to compatible inverters? Will inverter upgrades be required for older inverters?	A9: The exact technology pathway and protocols is the subject of a currently proposed ARENA project, but at a high level we expect to pass an export limit signal to the customer's aggregation platform. This may be the platform that comes as standard with the inverter, or a third party aggregation platform engaged by the customer. We expect to mainly offer flexible exports as an option for new solar customers. It is possible to upgrade an older inverter or add an external control box to an older inverter, although costs may limit this.
	Q10: Are you also able to supply any details of where the augmentation is planned, and when it will be rolled out, on different feeders/zsss? The heatmap for solar uptake is very useful – but some details about to assets upgrade	A10: We have a business case that will look to address voltage issues on a proactive basis. This business case will further develop the practical elements of the program including prioritization of sites and timing. At this stage we have identified known constraints, likely solutions and future constraints.

	schedule would be interesting.	
	Q11: Was there a consideration of non-network options for this problem – especially for zone substations that are facing augmentation for evening peaks?	A11: The non-network solution considered is the smart networks "DENOP" solution and this has been factored into our analysis. Changing transformer 'Taps' is a network solution but is low cost and opex in nature. This has also been factored into our analysis.
	Q12: Value of solar – we are keen to talk more about your approach to the value of solar.	A12: We used the feed-in-tariff (FiT) to value the export enabled of unserved generation. The FiT is an independent industry accepted metric of valuing the energy generated by small scale renewable generation. We also engaged Frontier Economics to evaluate the use of FiT as a proxy for the value of solar exports. Frontier Economics concluded that the use of the FiT provides a reasonable measure to estimate benefits of solar exports and it is also in line with the Australian Energy Regulator's regulatory investment test for distribution (RIT-D).
	Q13: Your innovation business plans include several projects targeted to more efficient ways to accommodate solar, such as Statcoms and batteries. Will some of your planned investment to accommodate solar preclude the application of this type of technology as it's established. Is there a case for a slower response to DER augmentation as some of these new solutions become commercialised?	A13: Innovation is uncertain and, if successful, often has a long pay-back period. That is why investing in innovation (where economic) is important. Our innovation proposals look to test/pilot ideas to see if they can be successfully implemented on our network. However, what projects will proceed will be determined through the new governance arrangements that we have established, including the establishment of the IAC. The IAC's role will be to evaluate and prioritise our proposed innovation projects. Importantly, our customers have indicated a willingness to pay for our innovation proposal. With respect to our proposed DER program, we have been given very clear guidance from our customers that their ability to export should be maximized where it is economically efficient to do so. Our proposed program captures two key programs: Voltage compliance program (to deal with existing voltage issues) and Hosting capacity for DER program (to deal with emerging voltage issues). We consider that our proposed program effectively balances the costs and benefits to our customers and enables significant additional solar generation. Voltage compliance program Currently, around 54,000 customers (both solar and non-solar), experience voltage issues. We are targeting voltage performance levels in accordance with AS 61000.3.100 (Steady state voltage limits in public electricity systems), which requires that 95% of sites must operate within the applicable voltage limits more than 99% of the time. This Standard recognises that occasional excursions from the permitted voltage limits are unavoidable and are not economical or practically possible to prevent. Capex of $20.6 million ($2021) will allow us to achieve the performance metrics set by the Code and the Australian Standard by targeting economically efficient

		augmentations. It will also improve the experience of 88% of the customers who are currently affected by voltage issues. It will also reduce constrained exports for these customers by 13%, although there will still be some network constraints at times. Hosting capacity for DER program This is a proactive program that targets areas that we expect will experience constraints or voltage compliance issues during the 2022-26 regulatory period. We are prioritising this project to ensure our customers will have the ability to export excess energy where the cost of us carrying out works is economically efficient. If we do not take appropriate action to reduce network constraints, we forecast that by 2025 nearly 30% of our customers (around 235,500 customers) will be experiencing voltage issues by the end of the 2022- 26 regulatory period. For $20.9 million of capex, we can improve the experience of 97% of these customers and reduce constrained exports by 70%. As it would be uneconomic to remove all constraints affecting DER entirely. Our calculations indicate that to achieve zero constraints would cost $626.1 million and would only improve the experience of an additional 7,000 customers on top of our proposed program. We also note that it is not economic to augment SWER lines to enable greater DER exports and that, even if the lines were augmented, customers may continue to face export limits on excess energy.
Relocating assets	**Q14: As peak load falls in some parts of the network, and rises in others, the suggestion has come up that it might be possible to relocate and reuse some assets. Is this something that [Ausnet] ever does? Are there types of asset for which this might be possible?**	A14: We can reuse and relocate assets. This is most relevant for distribution transformers and power transformers. For example, if we replace a 50kVA transformer with a 100kVA transformer we could reuse that 50kVA transformer somewhere else on the network where the demand is lower, or where that size is required. Similarly, a power transformer would be taken out and refurbished, then redeployed where it’s needed or kept as a strategic spare. Other assess can also be re-used, although there are often risks associated with doing so, which often limits our ability to do this.
IT Capex	**Q15: What IT upgrades are required for 5-minute settlement?**	A15: Several different upgrades will be required including: • The Meter Management System will be upgraded along with server processing and storage capacity increases to manage the growth in data volumes. • The Meter Data Management system, which currently provides aggregated data to the market and AEMO, will be enhanced to provide detailed meter data to AEMO.

		• The Meter Data Store system will be upgraded. • There will also be some: o data warehousing and reporting changes to support 5-minute interval data; o modificationstoStandingDataandSpatialDataplatformstocaterforunmeteredloads; and o upliftininfrastructureandenvironmentcapacitytosupporttheincreasedvolumeofdata. • Finally, the network billing system upgrade to support new 5-minute tariffs will be restructured to support 5-minute interval data.
Repex	**Q17: The 2018 EPA Amendment includes some new laws around noise that some distributors have considered to be relevant to their ZSSs. Did you consider these laws in relation to your assets, and do you think any of your zone substations are non-compliant with the new noise laws?**	Q18: We are not currently aware of any ongoing issues with the noncompliance of our ZZS with respect to noise. We are aware of the new (pro-active) obligations that the amended EPA Act requires. As part of our ongoing compliance we are, however, monitoring the amount of noise produced by our zone substations and may revisit this issue in our revised proposal.
	Q19: Is there a difference between the condition assessment, and replacement program for urban and rural areas?	A19: Our approach to assessing poles is consistent across urban and rural areas. However, certain criteria are met more in some areas than others which means that outcomes can be more consistent across some rural areas compared to some urban areas. Some of the criteria that we use include, for example: • Bushfire risk (higher bush fire risk = more concrete); • Presence of termites (more termites = more concrete); and • Presence of telecommunications wire (suggests wood replacement). We have a specific policy on pole replacement that lists the various characteristics that we consider when determining whether a pole should be replaced with a wooden pole or a concrete one.
REFCLs	**Q20: We appreciate that the REFCL program is mandated, not at Ausnet's discretion. Has there been/will there be a review of the performance of REFCLs**	A20: We have not undertaken a formal review of the effectiveness of the REFCLs at this stage as the 2019/20 summer was the first summer of mandated REFCL operation. However, over the 2019/20 bushfire season the REFCLs operated in response to network faults that otherwise could have resulted in a fire start. Over the 2019/20 bushfire season it was demonstrated that the REFCLs operate in real

	in particular, in the recent fire season. Has the impact of REFCLs on reduced fire starts, as opposed to other components like EDOs, been established.	world conditions and are delivering reductions in Victoria's bushfire risk. Over time we may be able to accurately quantify this risk reduction.
	Q21: REFCL ongoing compliance capex is larger than the REFCL spend – what does that entail?	A21: Our compliance program includes the installation of additional ground fault neutralisers, new transformers and, in some instances, the construction of new zone substations. The forecast cost of these augmentations is $97.8 million (direct, $2021) and comprises: • Kilmore South zone substation – Upsize the arc suppression coil (ASC); • Wonthaggi zone substation – Replacing a power transformer and installing a Ground Fault Neutraliser (GFN), resulting in Wonthaggi becoming a two GFN site; • Ringwood North zone substation – Installing an additional GFN, resulting in Ringwood North zone substation becoming a two GFN site; • Wodonga Terminal Station – Building a new zone substation and installing one GFN and extending a 66 kV line by 22 km; • Eltham zone substation – Building a new zone substation, installing one GFN, extending a 66 kV line by 5.5km and a 22 kV augmentation; • Bairnsdale zone substation – Building a new zone substation and installing one GFN; • Lilydale zone substation – Installing an isolation transformer and undergrounding works at Mt Dandenong; and • Belgrave zone substation – Load transfers and network augmentation (feeder re-conductoring and reconfigurations). We are continuing to look at opportunities to either defer or reduce the ongoing REFCL augmentation expenditure and are working with the Victorian Government and Energy Safe Victoria to look for opportunities to amend/refine regulatory obligations including the mandated performance standards.
Population growth forecasts	**Q22: The forecasted cost reductions for customers in the Jemena network depend on the population forecasts for**	A22: The COVID-19 crisis can be expected to negatively affect the forecasted cost reductions in the Jemena network based on lower projections for all our customer bases. However, while it is certain that an economic downturn will occur, the length and the severity is still unknown at this point and there may be some offsetting increases we are not yet aware of. We are in the process reconsidering

	Ausnet's growth areas (without customer growth prices are flat or increase). Any idea yet, of how that might be impacted by a possible economic downturn and reduced housing development?	our demand forecasts and we will be preparing revised forecasts as part of our revised proposal.

5 Appendix 3 – Questions and written answers provided by CPPALUE

Table 4 – CPPALUE questions and written answers

Augmentation **DER and Future network**	**1. Your solution combines some dynamic voltage control, dynamic export limits, and network augmentation. We are interested in understanding more about the planning decisions for the augmentation component in particular.**	We have modelled augmentations to only occur when there are net benefits to customers, and this principle will be the basis for our planning decisions. To determine whether an augmentation will occur, we will look to operationalise our model. For each site we will monitor the level of solar constraint, forecast the amount of solar that will connect, and what that will do to the level of constraint. If the value of the solar energy constrained exceeds the cost of the augmentation, we will undertake the augmentation. In practice, this means augmentation will most likely occur in sites with a lot of solar customers and where physical constraints bind often (i.e. the worst areas).
	2. Are active dynamic export controls – eg control via a signal, not just allowing inverters to shut off – going to be part of the solution for domestic and/or C&I customers?	Dynamic export controls are part of our solution. Our Digital Network project includes developing the capability to dynamically control inverters through a Distributed Energy Management System (DERMS). On constrained network circuits, however, this does not unlock additional solar (solar would be constrained either automatically via the inverter settings or via dynamical control when voltages rise) as the constraints are physical in nature. Rather, the DERMS improves customer equity by ensuring all customers' solar output is ramped down equally rather than those experience the highest voltages being tripped off completely, and it helps us to manage virtual power plants. We consider that dynamic control capability is an import tool in any solar strategy. The Solar Enablement business case and dynamic control element of the Digital Network business case is targeted at residential customers, however, it

		is likely we will introduce some form of dynamic control for C&I customers over time.
	3. If not, is this primarily because this solution has not been developed yet? How far (in terms of years) would you say you were, to implementing this type of dynamic export control at the customer level.	Dynamic control of inverters will be available in 2023 with further management capabilities being developed through to 2026.
	4. From reading the Digital network business case, it seems that the "network augmentation" component of this project is associated with transformer replacement, as per Appendix C. Does this relate to replacing transformers with larger-sized units, to accommodate a reverse flow at peak generation times that is larger than the peak demand under high loads? Or does it relate to transformers with modern functionality . Are these all distribution transformers – or are some at ZSSs?	In respect to the Solar Enablement business case, the augmentation rates are based on the actual historical cost of improving supply quality. Typically, the best solution is to install a higher capacity transformer that can supply more current and has a greater tapping range, or replacing the conductor. We expect that we will continue to employ these solutions, however, we will also continue to assess alternatives to see whether they become cost effective in the future (such as on load tap changers or low voltage regulators). In the business case, replacing transformers is not targeted at accommodating reverse power flows because the voltage constraints typically occur at much lower solar penetrations than are required for reverse power flows to become an issue. However, when replacing transformers, we will select an appropriate size to help ensure reverse power flows do not also become problematic at a later date. All the transformers discussed in the Solar Enablement business case are distribution transformers.
	5. As solar penetration rises on a part of the network, past the nominated threshold for constraint (eg 30%), what is the planned roll out for these different	If the Solar Enablement program is approved, penetration based thresholds will not apply for the large majority of our customers (a form of upfront connection constraint will only apply for customers on single wire earth return (SWER) lines). We will always seek to implement the least cost effective solution first and this was the basis on which our modelling was performed.

	solutions, ie, will dynamic control be instituted first, and then finally network augmentation?	The dynamic voltage management system (DVMS) is a relatively low cost solution that can be deployed network wide and will assist to lower voltages at peak solar times. Similarly, the new inverter settings that reduce the voltage rise associated with exports are now mandatory for all installations. The other solutions will be site specific. For example, if a site has a relatively modest constraint / has a relatively low solar forecast and has additional tap settings available, we will tap the transformer. This option is not available on older transformers that don't have taps and transformers that have already been tapped to the lowest setting. If the expected benefits exceed the cost we would look to augment the site. This could include conductor augmentation depending on the type of conductor currently installed or a transformer upgrade to both a larger transformer and one with more tap settings available. As new technologies become available, we will assess their suitability.
	6. Is the main purpose of network augmentation to reduce the amount of time that dynamic constraints will be imposed, as penetration rises?	Yes the purpose of augmentation is to reduce / eliminate the time solar is constrained at a site, although it is important to note these are physical constraints and not constraints imposed by us. As mentioned, under Solar Enablement, we will allow the large majority of customers to connect with export. However, when voltages rise too high, solar inverters automatically trip off (this is a protection mechanism that all inverters have installed in them as mandated by AS4777).
	7. If dynamic controls are used, without network augmentation (on a typical line,) can you give an indication of how often dynamic constraints will be imposed, as penetration increases (from 30 – eg 70%?) Thanks – your charts of forecast constraints on zsss across the network go some way to explaining this "Solar constraints by zone substation" – however it would be good to get a general indication of the relationship between percentage of constraint time and the	Distributor led dynamic control does not unlock more solar on constrained circuits. It can help improve solar customers' experience as mentioned above. How often dynamic control will be used is very much site specific based on the prevailing constraint. Some sites experience constraints due to high voltages at very low solar penetrations (particularly single wire earth return lines for example) and others can reach 100% solar penetration without any voltage issue. This depends on a number of factors such as the size of the transformer relative to the number of customers it serves, whether the transformer can / has been tapped, the type and condition of the conductor, how customers in that area use solar (e.g. is it mostly used for in-home consumption rather than exported) etc. It is because each area can be so different that we modelled the entire network based on actual prevailing voltages as the starting point.

	percentage constraint time, if that's possible.	
	8. For example, will dynamic controls mostly apply just for a few hours around midday on mild spring days? Or should they be expected all year. What is your current pattern for seeing problems caused by solar exports, and how do you expect this to change as solar penetration rises? Id still be interested to know what kind of general pattern this is seen in.	The frequency at which it will apply is site specific and depends on the extent of the constraint. The business case indicates the areas where solar is most constrained today and forecast in 2025 in figure 2. Spring is typically the worst season for export constraints as there is a lot of sun but less air-conditioning load (relative to summer) to 'soak up' the solar being produced.
	9. How will dynamic export limits be implemented – is this via signal to compatible inverters? Will inverter upgrades be required for older inverters?	Yes it is via a signal to the inverter. Only compatible inverters will be dynamically constrained (again noting this does not unlock solar). We are working together with the Victorian Government, which has ensured that be eligible for the Solar Homes subsidy, inverters must be controllable.
	10. Are you also able to supply any details of where the augmentation is planned, and when it will be rolled out, on different feeders/zsss?.	Our model forecasts a list of transformers on which augmentation will occur. The model provide us with a very robust indication of the scale of the problem, but we do not expect that the exact transformers that are flagged in the model (1,878 out of over 100,000 transformers in the networks) for augmentation will necessarily be those augmented. The actual outcome will depend on where customers connect solar, however, in figure 2 of the business case indicates the most highly constrained areas.
	11. Was a consideration of non-network options for this problem – especially for zone substations that are	Yes, we considered DVMS, new inverter settings, tariff designs, quasi export tariffs etc. These are considered in the Solar Enablement business case appendix A. We also published and consulted on a solar options paper (https://talkingelectricity.com.au/wp/wp-content/uploads/2019/05/Solar-options-paper_May-2019.pdf) in April 2019 which considered multiple options for enabling solar.

	facing augmentation for evening peaks?	
	12. Value of solar – keen to talk more about your approach to the value of solar.	Solar was valued based on the: ⍰ Wholesale fuel cost reduction ⍰ Price of carbon This was modelled by the independent consultant Jacobs. We have attached Jacobs' report for your reference and we note it is publicly available via the AER website.
	13. DVMS . This is listed as a trial – but does not seem to be included in the Digital Network initiative, or in the Solar business case. Will you increase your remote voltage management capability as part of this program?	We will be implementing a full DVMS system for CitiPower and Powercor as opposed to a trial as this has already been proved successful in our United Energy network where it has been implemented. The costs for DVMS are included in the Solar Enablement business case, for example in the Powercor business case please see table 1 and appendix C. A DVMS remotely, and dynamically, changes the voltage set points at zone substations. This affects the voltage at each distribution transformer supplied by that zone substation. It is an effective tool in reducing voltages when they are high, but also has limitations as it impacts on a number of sites, some which may be experience low voltages at the same time others are high. More information is also available in the Powercor business case section B.1.5.
Relocating assets	**14. As peak load falls in some parts of the network, and rises in others, the suggestion has come up that it might be possible to relocate and reuse some assets. Is this something your networks ever do? Are there types of asset for which this might be possible?**	Yes, we do. For example when we replaced 10/13.5MVA transformers with larger 25/33 MVA transformers due to load growth, we returned the original transformer to our stores and then installed them at other location when establishing new zone substations. Most assets, however, are retired because they are no longer fit for service due to the condition, age or asset type. For example, CitiPower is currently retiring the 6.6kV network because it is based on an old operating standard that is not meeting current requirements. As this entire operating voltage is being retired, we cannot reuse the assets. We also engage in innovative practices to reduce the total number of assets we need. For example, when transformers fail they can result in significant customer outages. Instead of installing additional capacity each zone substation to mitigate this risk, we have a single relocatable transformer with spaces set up in our zone substations to accommodate it at short notice should the existing transformer fail.

Augex	**15. Is there a reason VPN networks have a large augex spend relating to ACMA and 3G shutdown, not seen for other networks?**	Only rural networks need to operate a radio network to communicate with zone substations that are not covered by telecommunications or fibre networks, or to operate runback schemes for (typically) wind and solar generators. For example, CitiPower and United Energy do not have need a radio network only Powercor. We are not aware of whether other rural distributors are facing the same problem as Powercor. If not, it is possible ACMA is not reallocating the frequency band that they are using for 5G.
IT	**16. What IT upgrades are required for the 5 minute settlement?**	To comply with the five minute settlement rule change and AEMO procedures, during the next regulatory period, activities include upgrading our IT systems to support the retrieval, processing, storage and delivery to market of five minute interval meter data and installing additional communication devices to transport the increased volume of data from meters into our IT systems. The figures below describe the impacts on our IT systems to comply with the five minute settlement rule change. Please refer to attached Business cases PAL BUS 7.09, CP BUS 7.09 and UE BUS 7.09 for more information.
	17. EPA repex – relating to noise levels of zone substations. How many complaints do you get, in relation to noise from your ZSSs?	Approximately 15-20 per year per network.
	18. Largely, as you say in your attachments relating to this issue, **the new legislation and regs don't change materially from the previous framework. What has changed in the rules to require replacement at so many zss locations?**	While the noise exceedance levels may have remained the same as the current regulations, the expected approach to management of environmental risk has changed substantially. From 1 July 2020, we will be required to manage the risk of noise pollution (or other environmental risk) proactively by acting to reduce the risk of pollution as far as reasonably practicable. This is a significant shift from the way environmental risk is managed today, i.e. a more reactive approach where pollution is managed after it arises. The increase in our planned works reflects this change in management of environmental risk.
	19. Risk monetisation is finding more conservative rates for repex than your	The monetisation of risk is something that our networks are continuing to transition towards (e.g. we have typically used proprietary risk-based models for high-value, low-volume assets (e.g. transformers), but less so for high-volume, low-value assets). Fundamentally, it is about supporting better

	previous assessment methodology. However, are there inadequacies in the previous method used – ie have you seen unacceptable failure rates? If current rates are acceptable, is there a case for recalibrating the risk monetisation method now used, against the real-world evidence of current failure rates?	decision making on the timing of required works, and/or better targeting of specific assets within an asset class that result in the biggest risk reductions (i.e. making more informed decisions to intervene on the right assets at the right time). In this context, monetisation per se is not driving more conservative rates relative to our previous methods.
Wooden poles	**20. Is there a difference between the condition assessment, and replacement program for urban and rural areas?**	Our CitiPower and Powercor networks use the same pole inspection methods, and the same risk-based asset management program. However, the location of our assets do drive different outcomes. For example, in high bushfire risk areas (e.g. rural areas), our poles are inspected every 2.5 years, versus every 5 years for poles in low bushfire risk areas (e.g. urban areas). Similarly, the application of our risk-based asset management approach results in different outcomes for poles in urban and rural locations due to the different consequences of an asset failure in these areas. For example, a pole failing in a high bushfire risk location has a greater consequence of failure, and is therefore more likely to be replaced than a similar condition pole in a low bushfire risk location. Our consideration of failure consequence also has regard to reliability impacts (which all else equal, may result in greater replacement volumes in densely populated areas), although the consideration of reliability in our risk-based approach is less mature than our bushfire consequence modelling. Our United Energy network has a separate ownership structure, a separate asset management team, and subsequently, separate asset management policies. Notwithstanding this, the inspection methods are largely similar. United Energy's replacement program, however, is more condition-based (rather than risk) given the relatively consistent risk-factors throughout its network (i.e. the consequence of failure in United Energy's network is reasonably similar for any given pole).
REFCLs	**22. We appreciate that the REFCL program is mandated, not at your discretion. Has there been/will there be a review of the performance of REFCLs**	Energy Safe Victoria (ESV) has confirmed the REFCLs we have commissioned are meeting the required performance standards set out in the Victorian Government's Electricity Safety (Bushfire Mitigation) Regulations 2013, as amended. We record our REFCL performance data, which we share with the Victorian Government and ESV. On the days of the higher fire risk in this recent summer

	in particular, in the recent fire season. Has the impact of REFCLs on reduced fire starts, as opposed to other components like EDOs, been established.	(i.e. 2019/20), our REFCLs operated in response to a number of permanent and transient faults. With each fire season, we obtain more data on the operation of the REFCLs and soon we will be able to draw conclusions on their performance. Powercor has seen a reduction in fire starts across its network in recent years. This reduction can be attributed to our broader bushfire mitigation program rather than just REFCLs. We would support a government-led review of the effectiveness of the performance of REFCLs.