Victorian EDPR 2021-26 – online public forum

To assist stakeholders in accessing all responses received to the questions submitted as part of the online public forum, the Australian Energy Regulator (AER) has collated all the responses into this one document. The responses received in their original context have been uploaded on the AER Victorian EDPR 2021-26 public forum webpage.

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Australian Energy Regulator (AER)

Public responses provided by the AER

Received from	Topic	Question	Response
Consumer Challenge Panel 17 (CCP17) (questions for the AER and all DNSPs)	Efficiency	Can an efficient business and a high Efficiency Benefit Sharing Scheme (EBSS) payment for that business co-exist? What factors could lead to such an outcome?	Positive carryovers are accrued through making incremental efficiency gains. The later in the regulatory control period the incremental efficiency gains are made the greater the EBBS carryovers, since less of the gain will be retained within period. Efficiency gains are measured relative to the opex allowances set. Consequently the magnitude of EBSS carryovers will also be influenced by the accuracy of the opex allowances. We have adopted a degree of conservatism in setting these allowances, including on the threshold for considering a business efficient/materially inefficient. In this way the magnitude of EBSS carryovers achieved by an efficient business will depend on the threshold for determining whether a business is materially inefficient or not when we do our efficiency assessment of base opex. The tighter that threshold, and the potentially more accurate the opex forecast in general, the lower you would expect EBSS carryovers to be. Our opex efficiency analysis may also be impacted by changes in cost allocation and capitalisation practices by businesses, which is an issue that we are examining.
CCP17 (questions for the AER and AusNet Services	Asset lives	Is there a standard set of asset lives (and depreciation rates) for all businesses? If not, why not?	Standard asset lives are generally based on the technical lives of the assets that make up the asset classes in the asset base. Businesses may have different asset classes. For example, one business may use 10 asset classes for its asset base. But another business may employ a more disaggregated approach and use 30 asset classes for its asset base. Even for asset classes that appear similar across businesses,

			differences may emerge simply due to the mix of assets that make up those asset classes. We encourage consistency in standard asset lives across businesses. However, we also recognise there may be reasons that could affect the expected technical life of an asset in different locations.
Energy Users Association of Australia (EUAA) (asked from their presentation – to both AusNet and AER)	Capex	What analysis has been done by AusNet and the AER to show the extensive expenditure on mitigating bushfire risk (capex and opex) has been successful in reducing risk? (slide 13 from the EUAA presentation)	The AER's role is to approve prudent and efficient expenditure by distributors to meet their obligations under the Electrical Safety (Bushfire Mitigation) Further Amendment Regulations 2016 and has no role in monitoring bushfire impact and risk. The AER applies incentives on application of the Victorian Government's F factor scheme, which monitors fire starts. Data from this scheme may identify trends over the longer term. The Regulations were developed in the *Powerline Bushfire Safety Program* with extensive consultation, studies and expert guidance though the *Powerline Bushfire Safety Taskforce.* Questions related to the performance of distributors in terms of bushfire prevention and effectiveness of their expenditures to meet the Regulations should be directed to the distributors and the Victorian Government via https://esv.vic.gov.au/safety-education/bushfire-and-powerline-safety/.
EUAA (asked from their presentation)	Role of the AER	Can the AER confirm which particular matters that it proposes to bring less scrutiny to? Are these only the matters where there was agreement between the CF and AusNet or does it include all matters that were in the AER/CF agreed scope or the wider AusNet Services/CF agreed scope? (slide 8)	The AER is still considering all information before it including comments from stakeholders. It will use its various assessment tools – for example , trend analysis, modelling, assessment of bottom up builds, review of top-down challenges – to determine whether further scrutiny on particular matters is warranted.

AusNet Services

Public responses provided by AusNet Services

Received from	Topic	Question	Response
CCP17 (questions for all DNSPs)	Prices and reliability	Consumer engagement has consistently shown that consumers want price reductions and are happy with current reliability levels. The DNSP's have shown that reliability measures are generally improving while repex spending remains a significant proportion of total capex spending. Is price the main driver for considerations of reliability related spending?	Overall, forecast net capex for 2022-26 is 21% lower than net capex in the current regulatory period. The Value of Customer Reliability, determined by the AER through a large Australia wide survey, is a key input into these programs. This detailed and robust piece of customer engagement ensures network investment is aligned with customer preferences. Desired safety outcomes, largely determined by Government and the safety regulator directly, also underpin many replacement decisions. Our repex is generally driven by the need to restore asset condition in the most prudent and efficient way, to maintain reliability levels and safety in line with these customers' expectations. With respect to our proposed repex major stations, we undertook a survey of customers served by the relevant major stations to gauge preferences of price-reliability trade-offs. https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/charges-and-revenue/Major-Projects-Customer-Survey.ashx?la=en While there are limitations to the use of such survey results, generally the findings supported our major projects repex program as being consistent with customer preferences. In addition, this part of our repex proposal was negotiated and agreed with the Customer Forum.

	RAB Growth	We understand that proposed real RAB is growing for all 5 DNSP’s over the next regulatory period. RAB per customer is set to decline for some DNSP’s. Expecting that WACC will increase again, quite possibly during 2021-26, what impact would rising WACC have on customer bills?	We are the only business proposing a declining real RAB per customer. Therefore, as WACC increases, price increases will be lower and the effects of higher WACC relatively more muted. This smooths prices to our customers over time. In most systems, should an input (such as WACC) change, a change in outputs will be seen (although not necessarily on a one for one basis). If we were to increase the expected risk-free rate by 1% (starting from FY22) this would increase the overall forecast nominal WACC in each year by 0.40% out to FY26. This would, in-turn, produce an extra $95.2 million in (smoothed) revenue over the next regulatory period, which means that the average customer bill would increase by around $24 per annum (from $801 per customer (as proposed) to $825 per customer per annum).
	Asset lives	Is there a standard set of asset lives (and depreciation rates) for all businesses? If not, why not?	Clause 6.5.5(b)(1) of the NER, states that “the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets.” When considering the appropriate profile, we look at data on the historical life of our assets. Given differences between networks, including the environment and the historical configuration and use of assets, different asset lives (and depreciation rates) result. Suddenly resetting asset lives to become standardised would be unlikely to better reflect the economic lives for the assets of all networks, so would not meet the requirements of the NER and would likely lead to step increases and reductions in customer prices, depending on their network.

			It would also eliminate the ability for the depreciation profile to smooth customer prices over time.
	Opex	What were the criteria that were taken into account to determine that the proposed base year is efficient?	We nominated the 2018 calendar year as our base year as it was the most recent regulatory year for which audited regulatory accounts and other financial information was available. We note that we achieved significant savings from our efficiency program in both 2017 and 2018, which is captured in our base year expenditure. In 2018 total opex per customer was the lowest of all rural distributors (see figure 10-4 in our revenue proposal). This is despite the stringent bushfire obligations which drive far higher vegetation management costs for AusNet Services than for other distribution networks. The improving trend in efficiency we have achieved since 2016 also demonstrates that we have responded to the incentives under the regulatory regime and continue to seek further efficiency improvements over time.
	Step changes	How do each of the various proposed “step changes” meet step change criteria?	Our opex step changes do not double count costs included in other elements of the opex forecast. They were produced in a manner consistent with the AER’s “Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution” and through negotiations with the Customer Forum. This means that we consider (among other factors): • whether there is uncontrollable change in regulatory obligations; • when this change event occurs and when it is efficient to incur expenditure to comply with the changed obligation; • options to meet the change in regulatory obligations; • whether the option selected was an efficient option;

			• whether we can make the changes to meet the changed regulatory obligations, including whether it can be completed over the regulatory period; • the efficient costs associated with making the step change; and • whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.
	Efficiency	Multifactor productivity analysis (benchmarking) shows a declining utilisation of the network. Does this suggest that there is scope for greater efficiency of network utilisation without more spending, particularly on capital programs?	Asset utilisation in Victoria is much higher than other States (including for AusNet Services), demonstrating we generally run our networks harder. While we have not seen a strong declining trend in utilisation (throughput) over the last few years, we have nonetheless remained relatively constant. In addition, the economic benchmarking does not include the use of the network by solar customers export back into the grid. This has increased steadily over the last few years, so utilisation of the grid including by solar customers has increased. Despite the above, overall proposed net capex is 21% lower than expected net capex in the current regulatory period.
	Efficiency	Can an efficient business and a high EBSS payment for that business co-exist? What factors could lead to such an outcome?	Yes. In the absence of an EBSS there would no incentive for a network to make savings. If the strength of this incentive were to be reduced, it would encourage a lower level of cost savings. The EBSS has led us to pursue efficiencies which result in an opex forecast $148 million lower than would otherwise be the case. The first year of the current period (2015), was actually higher than the AER allowance, demonstrating the original allowance set in the 2015-20 EDPR was appropriate.

	Repex	We are not clear on the status and impact of the ESV report into pole failure risk in Powercor. It appears that the CPU group are approaching this report as a mandatory requirement. Could the DNSPs please be clear what activities are undertaken as a direct result of mandatory (legislative and regulatory) bushfire mitigation requirements, and which are being undertaken for other reasons?	Our REFCL program and REFCL driven augmentation activities are being undertaken as a direct result of mandatory bushfire mitigation requirements. Replacement of overhead conductors with underground or covered conductors in codified areas is also mandatory. There are also mandatory requirements in vegetation management and inspection frequency. Our remaining activities are driven by asset risk, reliability, safety and operational requirements. Some of these activities will also result in bushfire mitigation benefits, however, not as a result of mandatory requirements.
	DER Integration	Analysis from CCP17 and ECA suggests that the costs to integrate DER are similar to, or perhaps even higher than, utilities elsewhere who already have higher DER penetration. We would expect that with the quality and quantity of data available through AMI which provides extensive insights into customer terminal voltage, phase balance and the like, this would provide an almost unique opportunity to efficiently reduce some of the impacts, make better risk management decisions and provide a platform for innovative voltage management. Such opportunities are not clear in the proposals, especially in leading to lower DER integration costs and innovative grid voltage management.	AMI has given us greater visibility of steady state voltage performance. Using AMI data, we have developed a suite of analytical tools that allow us to determine which substations supply customers who experience ongoing, consistent voltage compliance issues. Our proposed program, which is based on AMI data, will allow us to carry out options analysis and propose a preferred solution for each constrained distribution substation (and which will maximise the net economic benefit to customers). The results of this analysis will allow us to observe actual customer voltage performance and the value of unserved generation of rooftop-solar due to voltage constraints using the feed-in-tariff. We note that the impact that different DER penetration levels have on a network depends on the network's configuration. For example, a highly utilised network, with longer low voltage (LV) circuits, will be more greatly impacted by the same level of DER penetration in an under-utilised network with relatively more distribution substation and shorter LV circuits.

		Would the distributors care to comment on this observation?	As noted above, Victorian networks are higher utilised than in other States.
	DER Integration	DER integration costs centre almost exclusively on managing voltage rise above legislated limits. Could the distributors comment on analysis that may have been done to implement advanced grid voltage management strategies or even voltage reduction. We also note that some utilities have offered voltage reduction as a demand response or market response opportunity, suggesting voltage reduction is possible. The change in household appliances suggests sensitivity to low voltage may be less than it has been in the past. Have distributors considered the risk and costs of reducing grid voltage and addressing low voltage issues as an alternative or delaying option to investing as widely in customer controls and LV augmentation? Have any trials to do so been considered or undertaken?	We have already carried out extensive low-cost improvements to manage voltage compliance. These include: • voltage regulating relay (VRR) setting changes at zone substations and line regulators; • distribution transformer tap changes; • mandating Volt-Var and Volt-Watt control requirements for new inverter connections; and • trials on developing an optimisation platform (Distributed Energy Network Optimisation Platform). In many cases, we have exhausted these opportunities. Further work is required to achieve the network performance required to accommodate the anticipated solar uptake and achieve voltage compliance. In many cases, where further work is proposed, lowering voltages is not practical due to the wide spread of voltages experienced by those customers throughout the day. With the increasing uptake of solar PV generation, the spread of voltages that a customer experiences throughout the day is forecast to widen, making simple, low-cost, solutions like lowering voltages less advantageous.
	Forecasts	How material is the disparity between the business's load forecast and AEMO forecasts, and what are the reasons for and implications of the disparity?	The difference between the AEMO demand forecast and our own forecasts was not found to be significant. AEMO and our own growth rates in demand were found to be very similar, which provides confidence in the assumptions around economic conditions and other growth factors that were used. To be precise, the annual growth forecast by AEMO for our terminal stations

			between 2019 and 2026 was 1.31% compared to our forecast growth of 1.34% (for demand at a probability of exceedance of 10%).
	Sensitivity analysis	In these difficult and very uncertain times no doubt the distributors are looking at their forecasts (customer growth, major infrastructure projects, demand growth, energy delivered and cost inputs) very closely. We recognise that there will be an opportunity to revise forecasts at the revised proposal stage. Can the AER and the distributors provide some insight into the key environmental variables they are watching, and what mechanisms they will be employing to revise the forecasts as necessary?	We note that there is a high degree of uncertainty around the current economic environment and how this will play out. We will, therefore, review our forecasts once there is more certainty. Nonetheless, we are tracking the changes in consumption of different customer classes, and will observe how changes in consumption patterns translate to winter peak demands. We also intend to model our summer demand forecasts given the timing of the revised proposal. We will also continue to be an active participant in AEMO's Forecasting Reference Group, which has ongoing discussions on the impact of COVID-19 on demand forecasts.
	Demand Management	Apart from those already outlined in opex step changes, could you provide information about the business's Demand Management programs for 2021-26, and how that differs from current programs?	We are currently proposing to continue the following demand management programs across the next regulatory period: ▪ GoodGrid customer demand response program (which covers both Residential demand response rebates and commercial customer CPD tariff); ▪ Network Support Contracts offered to targeted commercial and industrial customers in areas of network constraint; ▪ Mobile generation deployments to alleviate network loads at peak times; ▪ Non-network solution opportunities offered to the market in order to seek demand side alternatives to network upgrades; and ▪ Continued Critical Peak Demand pricing for large industrial and commercial customers, which has been in place since 2011 and continues to successfully reduce peak demand.

			Rather than deploying additional programs, we are more likely to continue and evolve these programs, including scaling up or down as required. For example, if we find that a demand management technology trialled under the Demand Management Innovation Allowance (DMIA) provides good value, we will seek to incorporate that technology into the way we operate some of our demand management programs. We intend to make full use of the DMIA in order to test and report on new ways in which to provide demand management solutions that can benefit our customers. Successful pilot projects under DMIA will be proposed for transition to "business as usual" deployment. DMIA projects across the next Regulatory period are expected to include the testing of demand response automation and management platforms, a continued focus on air-conditioning load management as well as an increasing focus on the management of electric vehicle charging loads. We also intend to leverage the Demand Management Incentive Scheme to engage third-party service providers to deploy solutions that will alleviate emerging distribution network constraints (e.g. defer traditional network asset augmentation).
	Consumer Engagement	Recognising that COVID-19 has dramatically appeared since revenue proposals were lodged, we would like to know what plans the individual businesses have for engagement in a setting where face to face engagement is likely to be constrained for a while yet? (Note that CCP17 believes that consumer and stakeholder engagement remains essential, but that the	We have been using different technologies (Skype, Microsoft Teams, telephone and email) to effectively engage with stakeholders during the Covid-19 pandemic. We have successfully used this approach for our engagement with CCP-17 and EUAA, Brotherhood of St Lawrence, and our internal CCC and will continue to do so until conditions change. This is in line with the approach taken by many industry bodies. We are open to feedback from customers and advocates of how they would prefer to engage during this time.

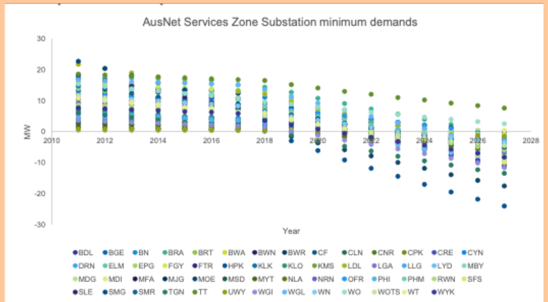
		methodologies for some engagement will need to be adapted.)	We have also been continuing our detailed customer research which has led to changes in business operations to meet changing customer preferences during the crisis.
CCP17 (questions for AusNet Services, Powercor and Jemena)	REFCL benefits	Significant investment has been made in REFCL technologies, along with a long history of other bushfire mitigation investments (sparkless fuses, reclosers and the like) to address fire risk. In addition, we note in the proposals the significant investment and operating costs associated with the need to manage and operate the REFCL systems, address the reliability degradation consequential to these installations and to update plant and equipment that no longer operates as required a result of the REFCL impact on the network. We certainly note the community benefits of the REFCL investment, and do not seek to revisit any cost/benefit considerations associated with this initiative. However, two things would greatly assist consumers' assessment of the DNSP proposals, being: (a) A consolidated view of the aggregate cost of the REFCL program and related expenses, and (b) clarity as to how the DNSPs have changed their approach to evaluating the residual BFM risk that drives their capital program as a result of the installation of the REFCLs? Can the DNSPs point to cost benefit analyses for work proposed	(a) In the current and forthcoming regulatory period, we are proposing to spend \$548.7 million (\$2021) on REFCL. This involves \$152.6 million (\$2021) in the forthcoming period, with the residual (\$396.1 million) incurred in the current period and the 6-month period starting 1 January 2021. (b) 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 world conditions and are delivering reductions in Victoria's bushfire risk. While it is too early in our roll-out of REFCL to accurately quantify this risk reduction (as mentioned above), we know that it is decreasing risk. For lines assets, BFM risk is evaluated based on historical fire ignition probability. When our analysis was undertaken there were no REFCLs installed and therefore no historical data. However, as more data becomes available, we will be able to capture the expected benefits from our approach to safety. However, we note that for some lines assets, the replacement program is driven by consequence, not risk, so REFCLs are not a relevant consideration. For example, bushfire risk is negligible for

		to address BFM risk that have changed since the installation of the REFCL systems?	stations assets as any fire would be contained within the gravel surface of the switchyard.
	Capex	The expenditure on REFCL technology has been significant, and the benefits in the reduction of bushfire start risk are noted. However, the large 'lumpy' expenditure on REFCL projects, in both the current and the next regulatory period, makes a 'top down' assessment of the capital investment proposals difficult. Would the DNSPs consider reframing their capex build-up and current period / proposed comparisons with the REFCL expenditure split out for clarity?	Splitting out our REFCL program results in gross capex of $1759.4 million ($2021) for the current period and $1667.7 million for the next regulatory period. Under this scenario, our forecast is therefore $91.7 million (5.2%) lower than the gross capex expected in the current regulatory period.
CCP17 (question for AusNet Services and the AER)	Bill impacts	Could you clarify the apparent discrepancy between the $110 per customer price reduction documented in AusNet's proposal, and the $12 price reduction in year 1 of Appendix A, Table 8 in the AER Issues Paper?	The $110 per customer headline is proposed total real revenue divided by the total number of customers. It does not include metering. The price path presented by the AER is produced on a very different basis. It presents the first year's price reduction from the 2020-21 year. This includes the mini year (first half of 2021), in which AusNet Services is forecasting revenues in line with 2022-26. AusNet Services has used 2020 as the baseline. The AER's price path is escalated over the period to account for energy, but not customer growth. Under a revenue cap, annual distribution pricing takes both these factors into account. We would

			encourage the AER to factor this into their price path projections for revenue capped networks. The AER's price path is also based on a representative customer on a single rate tariff. A number of assumptions can impact this result. Finally, we note that under our proposal the charge for electricity distribution services (excluding inflation) will be: ▪ $48 ($2021) or 10% less for a residential customer on average; and ▪ $627 ($2021) or 13% less for a non-residential customer on average.
CCP17 (question for AusNet Services)	Consumer Engagement	How will AusNet progress its consumer engagement now that the Customer Forum's role has been completed?	Our interaction with the Customer Forum has been an effective vehicle to drive cultural change across our business to become more customer centric. We will have committed to publishing a public Customer Interactions and Monitoring Report to provide visibility to our customers over the commitments we made to the Customer Forum and other key information that matters to them. In future resets, we will apply the significant learnings of the trial to our engagement approaches, noting that the trial cannot properly be evaluated until after the AER's Final Decision.
Brotherhood of St Laurence, Renew and VCOSS		The solar enablement augmentation works listed include line regulators, LV reconductor and LV split circuit, as well as old-type VRR replacement. Is the purpose of the LV reconductor work to replace these with higher-capacity lines – and does this imply that the exported peak generation will be greater than the	We leverage AMI data and analysis based on the voltage profiles of the meters connected to the substation. LV augmentation is only proposed on substations where customers are experiencing voltages that are outside of both upper and lower limits of AS 61000.3.100. Due to the nature of the voltage profile of these substations, voltage compliance levels cannot be met only by fixing local distribution transformer taps or changing the upstream HV voltage regulation.

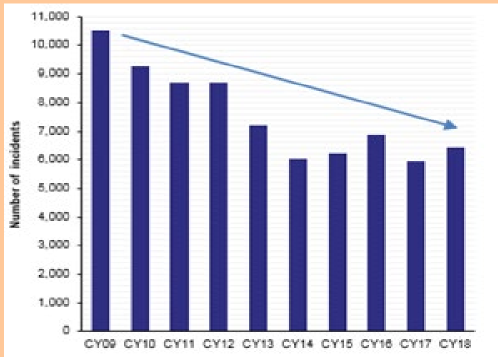
		peak load at these places in the network?	The most likely solution is the reconfiguration of the low voltage network by either reconductoring or splitting low voltage circuits. By reconductoring or splitting low voltage circuits the voltage spread (voltage band) experienced by customers will be narrowed and, while increased circuit capacity is an added benefit of the circuit reconfiguration, in this case the primary driver is the narrowing of the voltage band and the proposed solution does not imply that the exported peak generation will be greater than the peak load, although this could be the case in some locations.
		The augmentation elements of the solar enablement program include augmentation relating to the DENOP system (HV and LV.) What physical infrastructure or equipment does this relate to? Is this e.g. Dynamic switching and/or dynamic voltage tapping?	The augmentation component relating to our DER management capability (expected to be delivered via the DENOP or an equivalent DER Management System - DERMS) relates to sensor hardware for high resolution and real-time network monitoring, such as at distribution transformers. This is expected to be required to dynamically manage DER operation within network limits. Smart meter data is used to inform the overall level of management required, but it is not real-time in nature and therefore cannot be used to drive real-time DER management operations. Dynamic phase balancing and on-load distribution transformer tap changing are examples of techniques currently under consideration from an innovation perspective. If these are progressed towards broader implementation, a DER management platform such as DENOP could be integrated as part of the control environment. However, these techniques are not sufficiently developed at this stage to include in our proposal.
		As it is presented, the DENOP system appears set up in order to communicate with an aggregator or management system etc, while the VPN system seems to interface directly with consumers	The industry is aligning around an expected future state where DNSPs interact with an aggregator, or a management platform acting on behalf of the customer. The current industry working groups on DER management standardisation are focussing on this architecture. However, we do see the need to be able to directly interact with

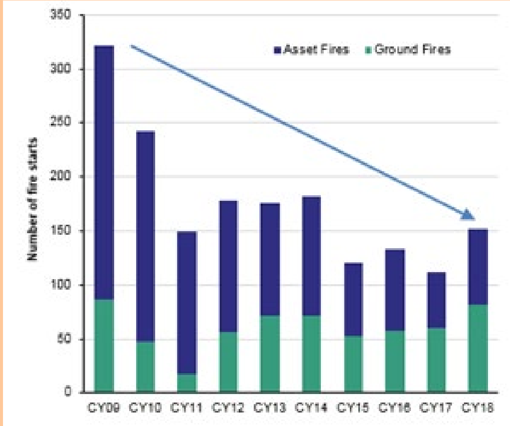
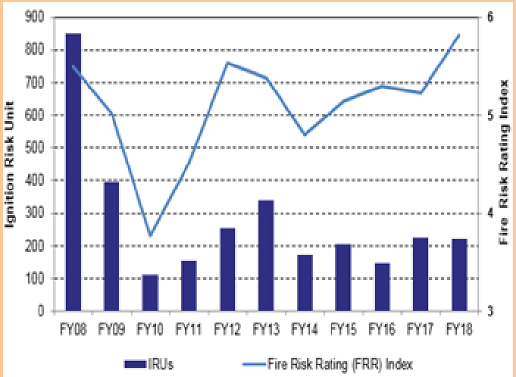
		(interface with IOT devices, DER control etc.) Is there a chance that the proposals from the distributors result in differences for the way customers or aggregators interact with the distribution network?	customers in some cases (such as network-initiated demand response programs, or where customer may prefer direct integration), so we are maintaining capability in our systems to enable this. While there may be some differences in the way that networks position their DER management options to customers, we expect this to be done in accordance with the evolving standards and technical regulations to ensure interoperability of devices and aggregation platforms across networks. This will avoid the so called "rail gauge" problem of different networks proposing to use different communications protocols or standards for DER management.
		Does the DENOP system allow the same functionality that is listed for the VPN digital networks strategy – specifically in relation to: - Dynamic voltage management - Dynamic phase balancing - Dynamic export constraint - LV model and Realtime LV power flow analysis - IOT platform for network sensors and customer sensors How do you understand the differences in functionality between the system proposed by Ausnet Services and the system proposed by VPN networks	Overall, we have a similar approach but with different emphasis. For context, DENOP is just one aspect of our DER management strategy and is our starting point for building capability in DER management through innovation trials. Over the course of the regulatory period we expect to build on the DENOP and ultimately transition to a DER Management System (DERMS) that is integrated into our core technology environment. The enabling technology investments are set out in the Technology capex proposal. The focus of these investments is on the DERMS itself, spatial data and systems integration, an integrated HV-LV load flow model, network sensing, and capability for flexible export management, demand response automation and local energy trading. The technology that we plan to put in place would provide the foundations for additional functions such as dynamic voltage management and dynamic phase balancing that we could deploy if we determine that they offer sufficient value.

		The chart below suggests that more than half of the ZSSs will be exporting generated load to the HV network by 2023. This develops very rapidly over the following 5 years so that almost all ZSSs will be exporting to the HV networks at minimum constraint periods. Much of this export can be expected to occur at the same time. Will this cause constraint on the HV network? How will this be managed?  Figure 3 – Estimated power flows at ZSS based on the pre Solar Homes Package Program (base forecast)	The current progress in addressing voltage issues includes setting changes in voltage regulators in the high voltage 22 kV network from forward line drop compensation (LDC) to uncompensated settings. We have used uncompensated settings to overcome the resulting over voltages in the 22 kV network with the adoption of solar generation in the distribution network. However, as the penetration of solar generation increases more feeders are likely to experience reverse power flow as shown in the figure (on the LHS). With the increase expected in reverse power flows, it is expected that voltage constraints will arise before thermal constraints. It is not possible to reduce the voltage set points further in flat settings in our HV voltage regulators without compromising the number of customers experiencing low voltage breach, generally during high demand periods. The existing voltage regulating relays (VRRs) with uncompensated settings are not sufficient to regulate the voltage for both maximum and minimum (including reverse power flow) loading scenarios expected throughout the day. Therefore, compatible VRRs and regulators are needed at zone substations and line regulators to accommodate customer generation while adhering to compliance requirements.
EUAA (from public forum presentation)		How does AusNet see its trend total/capex/opex productivity and performance against its peers trending if the AER accepts its 2022-26 proposal as currently presented? (slide 5)	While relative productivity will depend on a range of factors including the performance of the other businesses, and what costs are included or excluded (but customers still pay for) our proposal has several elements that will help improve our productivity vis-à-vis our peers. For example, we have committed to absorbing numerous additional opex costs within our regulatory base, contributing to an annual productivity saving of over 1%.

			As outlined above, we have the lowest opex (no exclusions) per customer of all rural distributors. Therefore, on the metric of what customers actually pay, we perform well. This is not readily apparent from the AER's benchmarking analysis as the economic benchmarking embeds historical differences in networks' capitalisation policies and does not always reflect the opex customers actually pay. We note that the AER has committed to reviewing its approach to different capitalisation policies and how to include bushfire risk as an operating environment factor. These issues, when addressed will provide greater transparency on our absolute and relative efficiency.
	Consumer engagement	What form will consumer engagement take from now on given the Customer Forum is finished? (slide 6)	AusNet Services' consumer engagement will take several forms, including: ▪ Continued use of the AusNet Services' Customer Consultative Committee (CCC); ▪ For this reset, discussions on a one-one basis, noting that we have we have used this approach already, including with the CCP-17 and EUAA/ Brotherhood of St Lawrence; and ▪ Continued customer research and increased grass roots engagement and listening (a reflection of the cultural change that has occurred within our businesses). The benefits of this can be seen in our much-improved responses to customer needs during the Bushfire emergency over the Summer and the current COVID-19 crisis. This has included relief and support payments, temporary generation and further investment in community resilience.

			We are also considering the lessons learnt from trialling the New Reg approach, and will look to capture the most successful elements of this going forward. Finally, we note we will be implementing a Customer Satisfaction Incentive Scheme and several customer experience improvement schemes. We will be held accountable for these as we will be monitored and reported on annually via a public Customer Interactions and Monitoring Report.
	Revenue building	What would have been the average price changes for non-residential without WACC and tax alliance changes – to compare with the $430 or 9% quoted (slide 9)	AusNet Services' proposal offers price reductions of $627 ($2021) for non-residential customers, from an average bill in 2020 of $4,798. In the absence of the WACC and the tax changes, and the lower expenditures proposed by AusNet Services, there would be an increase of $669, resulting in an average bill of $5,467. The total price reduction resulting from both lower expenditures and the WACC and the tax changes is $1,296 for non-residential customers. Of this, the WACC and tax changes account for $835, or approximately two thirds of the decline.
	Capex	What is the capex trend (% reduction over 21-26) excluding REFCLs? (slide 13)	As noted above, our REFCL program is significant and splitting this out (from the current and forecast period) would result in gross capex that is 5.2% lower than the current regulatory period.
	Tariffs	What evidence can AusNet provide to give our members comfort that their tariffs are not cross subsidising the Victorian Government roll out of rooftop solar for residential customers? (slide 15)	Our proposed expenditure on DER will put downward pressure on wholesale electricity prices due to additional low marginal cost generation. This benefits all customers, including our business customers. Our proposed expenditure will also ensure our customers can export excess energy only where the cost of us carrying out works is

			economically efficient. That is, we will only invest until such time as our solar, non-solar and business customers are better off. Our pragmatic and prudent approach to DER is reflected in, for example, our $20.9 million program for 'Hosting capacity for DER'. This program will allow us to improve the experience of 97% of our customers and reduce constrained exports by 70% rather than investing $626.1 million to ensure zero constraints.
EUAA (from public forum presentation – asked to both AusNet Services and AER)	**Capex**	**What analysis has been done by AusNet and the AER to show the extensive expenditure on mitigating bushfire risk (capex and opex) has been successful in reducing risk? (slide 13)**	We report our fire starts to the ESV. The current F-Factor regime uses geography and weather severity to convert these fire starts into a numerical measure, IRU's (Ignition risk units). As shown in the figures below, since 2009, the number of incidents with the potential to cause a fire and the actual number of fire starts caused by our assets has fallen absolutely and on a risk adjusted basis. These figures also suggest that despite weather conditions worsening we have been able to keep the number of fires down. **Incidents with fire potential** 

			Fire starts  **Ignition Risk Units vs Fire Risk Rating Index**  *Note 1: Under current arrangements, each fire is weighted by a "location factor" and a "fire risk (timing) factor". By applying these weighting factors to each fire, a fire will have a score called an "ignition risk unit" (IRU). As is demonstrated, the IRU has fallen sharply over the last decade.*

			Note 2: The Fire Risk Rating (FRR) is a risk weighted index of weather elements indicating how conducive the prevailing weather conditions are to ignition.
ECA, all DNSPs	DER Integration	Both the ECA and CCP17 have carried out some broad-brush analysis regarding the cost of integrating Distributed Energy Resources. This is useful analysis, and we appreciate the ECA also exploring this area. It is difficult to draw a conclusion as to the actual cost of DER integration as the costs are often spread across a number of categories (Augex, ICT capex, opex, innovation, LV remediation). Whilst the findings draw similar conclusions, we note some differences in the output of the analysis. CCP17 is happy to share the calculations behind our analysis. Our questions are: a) Could ECA share their analysis to help understand the different analytical approaches taken by ECA and CCP17? b) Could the utilities comment on the findings **[on page 41 of the CCP17's slide pack]**?	(a) N/A – this is a question for ECA. (b) We welcome the analysis that has been undertaken by CCP17. We do not have any concerns with the approach adopted by it in its analysis. It appears to have correctly identified the key DER projects. We note that the $11.4 million LV network capacity project is predominantly non-DER related. In the ordinary course of new customers joining a network or changing their demand profile this will necessitate the LV program even if no one installed solar panels. As such, it is appropriate that it forms part of our augmentation (and not DER) proposal. In developing our DER proposal, we engaged extensively with the Customer Forum, our customers and stakeholders to ensure an approach that focuses on delivering the best value for our customers.

Energy Consumers Australia

Public responses provided by Energy Consumers Australia (ECA)

Received from	Topic	Question	Reponse
CCP17 (questions for all DNSPs)	Opex	Forecast labour cost increases are a concern for most consumer-focussed submissions. Could ECA clarify why they support an averaging of the Deloitte and BIS Oxford forecasts?	Our view is that it is appropriate for the determination to compensate the distribution businesses for reasonable, well justified increases in labour costs over the next regulatory period. We agree with the CCP that it is important that the compensation be of a reasonable amount. That is, neither too low or too high. In reaching a position as to a reasonable compensation, we were informed by Spencer & Co's review of materials provided by the businesses. Spencer & Co took the approach to using an average of the forecasts provided by two reputable forecasters as this reduces the need to rely on the presumed accuracy of a single forecast, and is therefore more likely to result in a robust picture of future costs. In addition, we consider that this approach is more likely to produce a consistency of outcomes over time within each jurisdiction and also nationally. The networks presented evidence that of the two forecasters considered by AER in the past, DEA was a more accurate forecaster of costs at a national level in the case of SAPN, but BIS have been more accurate in Victoria. This suggests that the two forecasters vary in their approach and success between the state and national level forecasts. Given that neither forecaster is shown as being more accurate overall, and particularly at a time when economic conditions are very uncertain due to COVID-19, ECA agrees that it is prudent to use two forecasters rather than pick one against the other in different jurisdictions. We consider that the relevant labour market extends beyond the borders of Victoria. The key technical skills often required by distributors

			can in many cases be sourced from other jurisdictions. Further, it is our understanding that the businesses, as a matter of course, recruit key technical staff from other jurisdictions as their needs dictate. We want to stress that this is not a criticism of the CCP and its choice of the source of data. ECA welcomes the attention of the CCP to this area of costs and the potential impacts on consumers given the extraordinary financial pressure many households and small are under. It is important and appropriate to pursue the lowest possible cost of supply by distributors. Of course, consumers also value a reliable and dependable supply. Moreover, it is ECA's view that the businesses which will be subject to this determination should review further their expectation of labour costs and wage pressures. The economic impacts of COVID-19 may be expected to reduce wage pressures in Victoria and in Australia generally. A slowdown in economic activity is likely to result in a softening of the labour market, at least during the early part of the next regulatory period if not beyond. ECA would welcome further engagement with all stakeholders on the matter of labour costs. We believe it would be helpful for stakeholders to consider the following additional matters: • Three of the distribution businesses have proposed a higher proportion of costs allocated to labour which means that whichever labour escalator is chosen the impact of changes in labour costs will be greater for consumers serviced by those businesses • We are unclear whether all the businesses will pass on the change in the superannuation guarantee through higher wages. If consumers are to agree to add the super guarantee change on top of a wage escalator it would be reasonable for the businesses to provide evidence of wages agreements that every increment will be added to total wages in the next period; and • There is a lack of visibility of in how the businesses allocate costs between labour and materials, particularly when engaging external

			contractors. We expect that there is a significant variation in the proportion of contracted labour used by each of the businesses. More information would help consumers to understand that businesses are not choosing to allocate costs in favour of components likely to be subject to higher escalations.
CCP17 (questions for all DNSPs and ECA)	DER Integration	"Both the ECA and CCP17 have carried out some broad-brush analysis regarding the cost of integrating Distributed Energy Resources. This is useful analysis, and we appreciate the ECA also exploring this area. It is difficult to draw a conclusion as to the actual cost of DER integration as the costs are often spread across a number of categories (Augex, ICT capex, opex, innovation, LV remediation). Whilst the findings draw similar conclusions, we note some differences in the output of the analysis. CCP17 is happy to share the calculations behind our analysis. Our questions are: a) Could ECA share their analysis to help understand the different analytical approaches taken by ECA and CCP17? b) Could the utilities comment on the findings?	Comparing DER-related costs between the businesses is challenging. Each of the businesses has several programs that could be included in calculations of total spending on DER. To illustrate, in the case of Jemena, the Future Grid project has a cost of $31.75 per customer. However, including Jemena's Enabling DER program increases that amount to $98.64 per customer. For AusNet, the information provided in our presentation slides included a cost of roughly $59 per customer based on its Future Grid project. That increases to more than $85 per customer with the inclusion of other DER-related costs and additional LV network capacity. For Citipower, Powercor and United Energy, including the cost of related IT projects for solar enablement results in figures for costs that are close to those provided by the CCP. Advice from Spencer & Co is that discretion can be applied to inclusion / exclusion of certain projects like augmentation of LV capacity and power quality, as well as the Digital network Program at Citipower, Powercor and United Energy. The attached table from Spencer & Co provides updated information for these costs, including all the possible programs that could be included in these calculations.

Programs relating to DER, LV network overloading, PQ

Company	Jemena	AusNet	Citipower	Powercor	United Energy
DER capex	34,800,000	42,850,000	44,600,000	74,300,000	61,800,000
DER capex / customer	98.64	58.14	130.15	88.90	90.22
Future Grid	11,200,000	42,850,000			
Enabling DER - JEN	23,600,000				
Distribution sub augmentation (PQ) - JEN	3,600,000				
DER - Other IT - AUS		8,980,000			
LV Network capacity (due to overloads)		11,400,000			
Customer supply PQ		6,000,000			
Enabling solar			32,500,000	60,700,000	42,400,000
Solar enablement - IT			1,100,000	2,600,000	
Digital network program			11,000,000	11,000,000	19,400,000
Customer enablement			3,500,000	8,100,000	13,300,000
Voltage compliance program					
DER hosting capacity					

CitiPower, Powercor and United Energy

Public responses provided by [CitiPower, Powercor and United Energy]

Received from	Topic	Question	Reponse
CCP17 (questions for all DNSPs)	Prices and reliability	Consumer engagement has consistently shown that consumers want price reductions and are happy with current reliability levels. The DNSP's have shown that reliability measures are generally improving while repex spending remains a significant proportion of total capex spending. Is price the main driver for considerations of reliability related spending?	The AER only provide expenditure allowances to the business to maintain reliability, not to improve it. The distributor's actual expenditure on reliability is based on the AER's incentive schemes. The capital expenditure sharing scheme (CESS) and efficiency benefit sharing scheme (EBSS) provide an incentive to the distributor to spend less than the AER's expenditure allowance. The service target performance incentive scheme (STPIS) provides an incentive for the distributor to improve reliability. The sharing ratios and incentive rates of these schemes are set by the AER based on its assessment of a fair sharing of benefits and the value customers place on reliability.
	RAB Growth	We understand that proposed real RAB is growing for all 5 DNSP's over the next regulatory period. RAB per customer is set to decline for some DNSP's. Expecting that WACC will increase again, quite possibly during 2021-26, what impact would rising WACC have on customer bills?	Regulatory asset base (RAB) growth per customer depends on the level of the RAB, depreciation, net capital expenditure and customer growth. Each of these inputs into RAB growth per customer is a bottom up build and each should be assessed on their own merits. It is unsurprising that AusNet's RAB growth per customer is the lowest because it has the highest RAB per customer and it is proposing the highest accelerated depreciation. The only component of weighted average cost of capital (WACC) that can change over 2021-2026 is the debt rate. The debt rate is fairly stable because it is a trailing average and therefore changes to WACC are unlikely to cause material changes to prices over 2021-2026.

	Asset lives	Is there a standard set of asset lives (and depreciation rates) for all businesses? If not, why not?	Current AER practice is to aim for consistency over time for each distributor, rather than consistency between distributors. The default standard asset lives are based on the lives that were approved for that distributor for the current regulatory period. If a distributor wants to propose a change to a standard life it needs to provide strong evidence to the AER to justify the change. Our networks have not proposed to change their standard lives from the current regulatory period.
	Opex	What were the criteria that were taken into account to determine that the proposed base year is efficient?	We consider our base year expenditure is efficient for the following reasons: • our businesses are classed as the most efficient networks in the National Electricity Market (NEM) • we are subject to an incentive framework to which we have responded and continue to respond • we ensure efficiency of our operations by market-testing and engaging competitive contracts where possible. For further details, please refer to appendices CP APP02, PAL APP02 and UE APP02.
	Step changes	How do each of the various proposed "step changes" meet step change criteria?	Table 1 below summarises how our step changes meet the AER's step change criteria.
	Efficiency	Multifactor productivity analysis (benchmarking) shows a declining utilisation of the network. Does this suggest that there is scope for greater efficiency of network utilisation without more spending, particularly on capital programs?	Localised maximum demand is a key driver of our forecast capital investment. For our businesses this continues to grow in line with Victoria's population growth. Powercor and United Energy networks are also two most heavily utilised networks in Australia. Similarly, CitiPower is

			the most highly utilised CBD networks (recognising it is subject to legislated requirements regarding the security of supply that requires additional redundancy). None of our networks have declining utilisation.
	Efficiency	Can an efficient business and a high EBSS payment for that business co-exist? What factors could lead to such an outcome?	All businesses can achieve efficiency improvements and receive an EBSS reward. However, for efficient networks to achieve efficiency savings they must invest in innovative operations and effectively 'push out the efficiency frontier', rather than implement already established practices that simply allow them to catch-up to the efficiency frontier. We are efficiency frontier networks and the EBSS has created strong incentives for us to continuously invest in innovative ways of reducing costs for long term, e.g. automation technologies, organisation restructuring, contract renegotiations and similar.
	Repex	We are not clear on the status and impact of the ESV report into pole failure risk in Powercor. It appears that the CPU group are approaching this report as a mandatory requirement. Could the DNSPs please be clear what activities are undertaken as a direct result of mandatory (legislative and regulatory) bushfire mitigation requirements, and which are being undertaken for other reasons?	Energy Safe Victoria's (ESV) report set out 13 separate recommendations regarding our wood pole asset management practices. Our pole management improvement plan details how we will respond to each of these recommendations and has been included in our bushfire mitigation plan (BMP). Including the plan in our BMP means it becomes a regulatory obligation, and we will be held hold to account for the delivery of the plan. In addition to ESV's report, we operate in accordance to our mandatory Electricity Safety Management Scheme (ESMS) as accepted by ESV. This ESMS outlines how we deliver our general duties as per section 98 of the Electricity Safety Act, more specifically outlining how we manage our network assets to minimise risk as far as practicable. This means that once a wood pole is classified as 'unserviceable', we must action this

			pole within specified timeframes. Poles can be classified as unserviceable following our inspection and assessment practices (as endorsed by ESV) based on either measured condition or other visual defects that may compromise the structural integrity of the pole (e.g. clear signs of visual rot, termite or fungal damage, or large cracks).
	DER Integration	Analysis from CCP17 and ECA suggests that the costs to integrate DER are similar to, or perhaps even higher than, utilities elsewhere who already have higher DER penetration. We would expect that with the quality and quantity of data available through AMI which provides extensive insights into customer terminal voltage, phase balance and the like, this would provide an almost unique opportunity to efficiently reduce some of the impacts, make better risk management decisions and provide a platform for innovative voltage management. Such opportunities are not clear in the proposals, especially in leading to lower DER integration costs and innovative grid voltage management. Would the distributors care to comment on this observation?	The Powercor and SAPN networks are similar in terms of customers served and line length. Nevertheless our costs are $80-100 million lower than SAPN's to effectively manage 35% solar penetration. Smart meter data has played a critical role in identifying constraints, quantifying impacts and ascertaining the most efficient solution as is evident throughout our business cases. Compared to distributors in other jurisdictions, we are providing clarity on what we will deliver e.g.: • allow all customers to connect solar • enable 5kW export capable connections connection • remove 95% of solar constraints enable customers to export, which means Powercor is unlocking 423 kWh of solar for the average customer per annum at the end of the regulatory period. As discussed in our business cases (PAL BUS 6.02, CP BUS 6.02 and UE BUS 6.06), we are engaging in innovative solution that build on our smart meter capabilities, including developing a dynamic voltage management system and a distributed energy resources management systems.

	DER Integration	DER integration costs centre almost exclusively on managing voltage rise above legislated limits. Could the distributors comment on analysis that may have been done to implement advanced grid voltage management strategies or even voltage reduction. We also note that some utilities have offered voltage reduction as a demand response or market response opportunity, suggesting voltage reduction is possible. The change in household appliances suggests sensitivity to low voltage may be less than it has been in the past. Have distributors considered the risk and costs of reducing grid voltage and addressing low voltage issues as an alternative or delaying option to investing as widely in customer controls and LV augmentation? Have any trials to do so been considered or undertaken?	Our United Energy network operates a dynamic voltage management system (DVMS) and we have proposed to implement this in the CitiPower and Powercor networks as part of Solar Enablement. This solution, both remotely and dynamically, changes zone substation voltage set points. This means at times of high voltages, it will reduce the voltages of every customer on that zone substation and vice versa at times of low voltages. More information is available in our business cases—for example see PAL BUS 6.02, section 5.2.2, B.1.5 and appendix C. As pointed out in the question, we currently offer this type of service for demand management. The key difference is we will now be automating the process with our DVMS to replace the current manual process. A manual process is reasonable for demand management given we only provide this service for a few critical hours per year at particular zone substations. To enable solar however we will need to provide this service network-wide and continuously. We would like to clarify that CitiPower, Powercor and United Energy's solar costs are not centred on managing voltage rise to be within legislated limits. Our costs are centred on customer impact. That is, we are seeking to remove instances of voltages reaching the voltage point at which inverters automatically trip off and stop producing solar, at which point all customers lose the benefit of solar generation. We performed a cost benefit analysis to remove constraints based on the value of enabling solar to customers i.e. where the benefits all customers receive exceed the cost removing the constraint. In our business case we point out that code compliance is not a standalone identified need because it could lead to untenable and uneconomic outcomes. For example, meeting the Code

			requirements with respect to solar could be achieved by restricting all exports or allowing all exports and undertaking significant (and uneconomic) network investment. Both of these options are a simplistic view that does not take customer preferences into account. Therefore we consider any approach to enabling solar should contribute towards, rather than detract from our Code obligations—particularly given these obligations are in place to protect customers from poor supply quality—but not target Code compliance as the primary outcome.
	DER Integration	Both the ECA and CCP17 have carried out some broad-brush analysis regarding the cost of integrating Distributed Energy Resources. This is useful analysis, and we appreciate the ECA also exploring this area. It is difficult to draw a conclusion as to the actual cost of DER integration as the costs are often spread across a number of categories (Augex, ICT capex, opex, innovation, LV remediation). Whilst the findings draw similar conclusions, we note some differences in the output of the analysis. CCP17 is happy to share the calculations behind our analysis. Our questions are: a) Could ECA share their analysis to help understand the different analytical approaches taken by ECA and CCP17?	We consider that the total cost of managing solar should be considered in an analysis of solar costs rather than only the costs over a single regulatory period. SAPN's and Energex's growth in solar occurred predominantly over the period 2015-2020 and they were funded over that period to support that growth. In contrast, we've been managing solar without any regulatory allowance to date. Going forward, we face increasing demand for solar driven by Victorian Government incentive programs that will see similar levels of solar penetration seen by SAPN, particularly in the Powercor network, by 2026. That means the full costs of bridging the gap between current and expected demand for solar will be incurred over the next regulatory period. It is also important to consider the different outcomes of distributors' solar programs. Our solar program delivers: • 5KW export capable connections connection (with some exceptions for customers on SWER) • remove 95% of solar constraints. Powercor is unlocking 423 kWh of solar per customer per annum at the end of the regulatory period, which is more solar than

		b) Could the utilities comment on the findings?	outlined by other distributors. Considering distributors' future network programs more broadly, which include IT costs and operating costs for solar, electric vehicles and operating the network more efficiently in the face of change, further demonstrates the value of our program. This comparison is shown in table 2 below.
	Forecasts	How material is the disparity between the business's load forecast and AEMO forecasts, and what are the reasons for and implications of the disparity?	Our forecasts differ to AEMO's due to methodological differences. A detailed assessment of the differences in our forecasts to AEMO's is provided in attachments CP ATT022, PAL ATT022 and UE ATT022. While we compare our demand forecasts with AEMO's to identify discrepancies, we have found our forecasting approach is more reliable as it takes account of localised network and economic conditions. As the recent maximum demand record shows, some areas of our network are experiencing strong demand growth. We forecast specific demand drivers at each terminal station level to ensure that growth corridors are appropriately captured in the modelling, unlike AEMO that forecast demand based on observed trends in the data at a terminal station level reconciled to state-wide forecasts. An implication of using AEMO's forecasts instead of our methodology would be not capturing growth areas accurately and potentially threatening security of supply in that area. For our 2016-2020 revised regulatory proposal, CIE, Oakley Greenwood and GHD also reviewed AEMO's forecasting approaches and found them to be lacking in a number of aspects. Key areas of concern with AEMO's approach include: AEMO's connection point forecasts fail to incorporate key drivers of demand at the connection point level and therefore do not allow the responsiveness of demand to key drivers to

			differ spatially • AEMO's reconciliation process under-utilises information at the connection point level and results in a simple apportionment of state-wide forecast growth across connection points • AEMO's forecasts are insufficiently weather normalised and therefore result in unrealistically low starting point for the forecasts, leading to lower demand across the forecast period AEMO's forecasts are not accurate and unbiased.
	Sensitivity analysis	In these difficult and very uncertain times no doubt the distributors are looking at their forecasts (customer growth, major infrastructure projects, demand growth, energy delivered and cost inputs) very closely. We recognise that there will be an opportunity to revise forecasts at the revised proposal stage. Can the AER and the distributors provide some insight into the key environmental variables they are watching, and what mechanisms they will be employing to revise the forecasts as necessary?	In the preparation of forecasts, the key variables we will be watching are gross state product (GSP) for Victoria and population growth by statistical region. We will also be closely examining movements in interest rates, inflation and Electricity, Gas, Water and Waste (EGWW) services wage price index for Victoria. Finally we will be monitoring data produced by the Australian Construction Industry Forum (ACIF) for Victoria and our region. From an internal perspective, we will be closely examining demand over summer 2019/2020 and our pipeline of high and low volume connection activity. In terms of when we may revise our forecasts, at this stage that is not likely to occur until our revised proposals. The advice we have been provided by our external forecasters is that at this point, it is very difficult to forecast what may occur until the Federal and State Government roadmap out of COVID-19 restrictions is known.
	Demand Management	Apart from those already outlined in opex step changes, could you provide information about	United Energy has been leading the industry in seeking and implementing opportunities to deliver savings through demand management programs, which substitute capital

		the business's Demand Management programs for 2021-26, and how that differs from current programs?	expenditure with operational expenditure. As outlined in the regulatory proposal, we are continuing to expand the Summer Saver demand management program, to defer augmentation at the distribution substation and low voltage level of the network. We are also deferring $32 million of capital investment for a new line in the Lower Mornington Peninsula via a demand management solution with Greensync, and deferring around $26 million of capital works at Cranbourne Terminal Station. We will continue to contract with large commercial and industrial customers to avoid load shedding from network capacity constraints and to participate in the AEMO's scheme to reduce demand and avoid load shedding on peak days when there is a shortfall of generation. We have also recently begun the Bayside Battery trial in which we will mount two 75kWh batteries on poles that will charge when demand is low or solar exports are high, and discharge during peak times to avoid augmentation. This is the first time batteries have been used on low voltage network to power homes and businesses. CitiPower and Powercor also participate in AEMO's scheme to avoid load shedding. We are also continuing the energy partner program (EPP) works by offering eligible customers (i.e. those in locations where our network is constrained) a smart device that controls the temperature settings of their air conditioner during scheduled demand response events. For example, in the 2019/2020 summer, 1,067 customers on the Bellarine Peninsula were enrolled in our EPP. We will be developing a new platform that will automatically identify and schedule demand response events using historical data and forecast weather conditions.

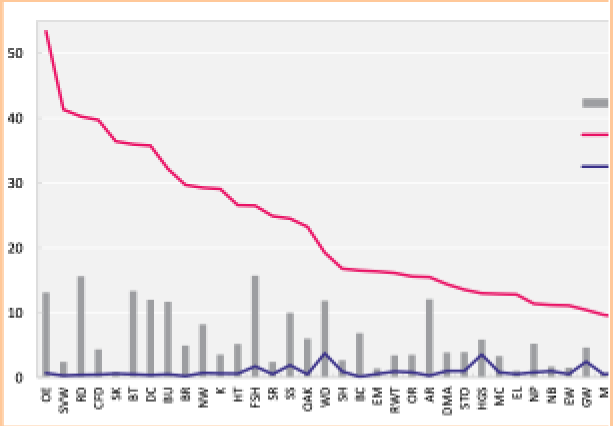
			Our Digital Network proposals will help us to expand our demand management capabilities further and defer more augmentation in the future.
	Consumer Engagement	Recognising that COVID-19 has dramatically appeared since revenue proposals were lodged, we would like to know what plans the individual businesses have for engagement in a setting where face to face engagement is likely to be constrained for a while yet? (Note that CCP17 believes that consumer and stakeholder engagement remains essential, but that the methodologies for some engagement will need to be adapted.)	Whilst we do not have firm plans for our post draft decision engagement, we are currently consulting on our proposed Customer Service Incentive Scheme (CSIS). Based on advice for our engagement specialist, we are conducting an adaptive engagement that uses remote online focus groups to test our proposals with consumers. The groups provide large flexibility to for participants to participate at a time that best suits them, and in a manner they prefer. This program is currently being undertaken. We continue our meetings with key stakeholders online, which has in some aspects improved communication with inter-state stakeholders. Beyond that it is difficult to be specific but whatever approach we do take will be guided by State Government health advice and the advice of our engagement experts.
CCP17 (questions for AusNet Services, Powercor and Jemena)	REFCL benefits	Significant investment has been made in REFCL technologies, along with a long history of other bushfire mitigation investments (sparkless fuses, reclosers and the like) to address fire risk. In addition, we note in the proposals the significant investment and operating costs associated with the need to manage and operate the REFCL systems, address the reliability degradation consequential to these installations and to update plant and equipment that no longer operates as required a result of the REFCL	Powercor has received $365m ($2021) for REFCL deployment so far through the 2016–2020 regulatory determination and contingent project applications. For the 2021–2026 regulatory period, we are seeking a further $102m ($2021) of capital expenditure to complete the deployment program and $60m ($2021) of capital expenditure to maintain ongoing compliance. In addition, we have sought $13.3m ($2021) of operating expenditure for annual compliance testing, re-balancing works and engineering support for REFCLs over the 2021–2026 regulatory period. In 2019, with the assistance of CSIRO, Powercor developed a

		impact on the network. We certainly note the community benefits of the REFCL investment, and do not seek to revisit any cost/benefit considerations associated with this initiative. However, two things would greatly assist consumers' assessment of the DNSP proposals, being: (a) A consolidated view of the aggregate cost of the REFCL program and related expenses, and (b) clarity as to how the DNSPs have changed their approach to evaluating the residual BFM risk that drives their capital program as a result of the installation of the REFCLs? Can the DNSPs point to cost benefit analyses for work proposed to address BFM risk that have changed since the installation of the REFCL systems?	bushfire risk model that quantifies the residual bushfire risk throughout our network. The model is also able to calculate the risk reduction that will be achieved for a given mitigation option. The model includes a risk reduction factor for REFCLs that was calculated by the Powerline Bushfire Safety Taskforce (PBST). When a REFCL is placed into service, the residual risk on that part of the REFCL-protected network reduces (note: REFCL risk reduction benefits are only applicable on the 22kV network). Powercor uses this model for any ongoing bushfire mitigation investments. Where a further mitigation option is being considered on a REFCL network, there is less residual risk to mitigate, which will be reflected in future investment proposal analysis.
	Capex	The expenditure on REFCL technology has been significant, and the benefits in the reduction of bushfire start risk are noted. However, the large 'lumpy' expenditure on REFCL projects, in both the current and the next regulatory period, makes a 'top down' assessment of the capital investment proposals difficult. Would the DNSPs consider reframing their capex build-up and current period / proposed comparisons with the REFCL expenditure split out for clarity?	Our investments in REFCL technology are a key component of our historical and forecast expenditure program. The modelling we submitted with our regulatory proposal (e.g. PAL MOD 6.09) provides stakeholders clear visibility on the impact of this program on our total investment portfolio.
CCP17 (question for CitiPower, Powercor	Step changes	Why are the EPA amendment step changes higher than those for the other businesses?	Our EP Amendment Act step change is based on our interpretation of the draft regulations published in September 2019. We cannot speak to other distributors' interpretation of the draft regulations however, it is possible our interpretations of the draft regulations are different. This can be for a number

and United Energy)			of reasons: • they have a different starting point—our status quo under the existing regulations is to react to already occurred environmental damage (at a lower cost to our customers) while others may already have proactive measures in place to reduce risk of environmental damage occurring • they have different building standards—each distributor manages their assets to their asset management policies and standards, resulting in different zone substation layouts between distributors and varying environmental challenges • they have a different approach to measuring environmental risk—our proposed environmental program is based on a desk-top risk assessment that ranks sites according to risk of environmental damage occurring, and proposes mitigation of highest risk sites first. Others may not have a risk-based approach developed to date, or their risk appetite may differ. We are currently considering implications of the 12 month deferral of the new EP Amendment Act and the likely delay in the final regulations on our regulatory proposals.
	Repex	We appreciate the feedback received from engagement that reinforces the concern by some communities regarding the current state of pole safety and bushfire start risk. We also understand the need for some utilities, especially Powercor, to respond to that engagement. The change to pole safety assessments to include wood fibre strength is noted. Could PC in particular outline what they have done in pursuing 'non-asset' solutions to mitigate the perceived risk of pole failure and	In May 2019, we changed our asset management practices to increase the frequency of inspections for wood poles classified as 'added-control serviceable'. The increased frequency of our inspection program is reflected in our forecast improved pole staking ratio (i.e. the percentage of pole reinforcements relative to total interventions). Pole reinforcement extends the life of wood poles where safe and practicable, and is an alternative to replacement. Our 2019 asset management changes also included changing the labelling of 'limited life' poles to 'added-control serviceable' poles. The change was driven by concerns from the public

		fire start? For instance, we would expect changes to pole inspection frequencies in high risk areas, different staking regimes, recognition of the impact of bushfire mitigation (BFM) measures and the like to be a large part of the response.	that poles identified as 'limited life' had not been replaced, even though it was not necessary to replace or reinforce the pole based on our condition assessment. We also changed our practices to affix an 'added-control serviceable' sign to poles, whereas these poles were previously marked with a large white 'X'. In effect, both these non-asset changes were aimed at better educating and communicating with our customers. A further focus area, as set out in our pole management improvement plan, is to develop the use of non-destructive technologies for inspecting wood poles. The intention of this initiative is to identify technologies to support assessments where our current system relies solely on visual observations, and to do so in a way that does not compromise the integrity of the existing asset. In regard to the impact of other bushfire measures, our pole consequence stratification distinguishes between SWER and non-SWER REFCL areas (with non-SWER being lower consequence, due to REFCL coverage). REFCLs, however, only operate for single-phase to ground faults, meaning it remains important to ensure we undertake prudent measures to manage our wood pole population in REFCL areas.
	IT Capex	Please clarify how CPU's investment in IT facilities to provide customer usage data will relate to or interface with AEMO's implementation of the Consumer Data Right for energy.	The Consumer Data Right allows AEMO to provide individual and aggregated usage data to customers and third parties (with customers' approval), based on day-old MSAT data. Our customer enablement program will provide customers access to near real-time usage data at 15-minute intervals and on a mobile application. The IT platform within the customer enablement program will also provide a one-stop-shop portal where customers can view all the information related to their supply under one login,

			including insights into their usage and export patterns. It will also allow for enhanced customer experience through improved online capabilities, more effective outage SMS notifications and notifications on the efficiency of customers' rooftop solar output and exports
Brotherhood of St Laurence, Renew and VCOSS		In point 5.2.2 of the Solar Enablement business case, you explained that the DVMS (dynamic voltage management system) would allow a greater amount of solar PV to be connected before experiencing constraints. How much does dynamic voltage control increase the PV capacity of a line? If constraints are assumed to occur at 30% penetration normally, at what penetration would they occur if voltage control was implemented (if that is a simplification – are you able to express the extent of improvement in other terms?) Do you have a sense of how the chart below would be impacted for each distributor by rolling out DVMS and dynamic controls, without the augmentation such as transformer and LV asset replacement needed to allow PV to be exported to the HV network?	The impact of DVMS depends on the site. Where there is a tight voltage range between all the customers supplied from a zone substation, it will have more impact. However, on some zone substations, there is a greater voltage range and some customers will be experiencing lower voltages while others experience higher voltages. In these circumstances, it is not possible to alter zone substation voltages (via DVMS) as much because doing so affects every customers supplied by it. Figures 1 and 2 are recreated charts for CitiPower and Powercor to show the impact of DVMS, United Energy already has a DVMS in place and so this analysis is not relevant. While DVMS has a broad impact, there will still be material solar constraints if it is the only solution implemented. For example, customer connected to the Geelong zone substation will still be constrained from using solar 42% of the time in 2025 even after implementing a DVMS. Also DVMS requires field work to be implemented effectively – much of this field work incorporates the costs contained in the business case.

		Figure 10 Solar constraints by zone substation (percentage of daylight hou 	
		A large cost item in the DER plan is the replacement of transformers, and sometimes other LV assets. Replacing transformers appears to differ from the augmentation proposed by Ausnet Services, who are proposing to replace old type ZSS and line regulator VRRs with 2-way models, as well as LV reconductor work and split circuits. Why have the VPN networks determined that transformer replacement is required, rather than VRR replacement? Are these transformers being replaced to accommodate a larger (reverse) peak flow, or are they being replaced for specific functionality reasons (Eg 2-way flow)?	Our proposed augmentations (which only occur if lower cost solutions are not available and there are net benefits from undertaking the augmentation) are based on the historical make-up and cost of remediating supply quality issues We already have two way voltage regulation relays (VRR) at most of our zone substations. This is the key network hardware that will allow us to implement a DVMS. Splitting circuits typically involves installing distribution transformers, and the cost build-up of our solution also includes a component for LV conductor works. As such, the capital solutions that we and AusNet are proposing are not so different based on the information in your question. Transformers are typically replaced because higher capacity transformers can supply more current and new transformers have a greater tapping range—both of which improve supply quality. 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.
		As it's presented, Ausnet's DENOP system appears set up in order to communicate with an aggregator or management system etc, while the VPN Digital Networks program seems to interface directly with consumers (interface with IOT devices, DER control etc.) Is there a chance that the proposals from the distributors result in differences for the way customers or aggregators interact with the distribution network? How do you understand the differences in the functionality between the two proposed programs?	We are building a platform that interfaces with customers' inverters to dynamically set minimum (e.g. for batteries) and maximum operational limits (called an operating envelope). Aggregators can use their own platforms to control inverters within these envelopes or they can use our digital network platform. This is best illustrated with an example. At times of / locations with low solar production, we may set a dynamic maximum export limit of 5kW, which is the same as our static limit whereby customers can install inverters capable of exporting a maximum of 5kW. However as exports and network voltages rise, we may change our dynamic limit to 4kW. We will do this via direct interface with customers' inverters, so that each inverter is only capable of exporting 4kW. Within this operating envelope of 0-4kW of export, an aggregator may decide to control customers' inverters to only export 3kW (perhaps to charge customers' batteries for later use when the aggregator can extract more value from exports), however, they will physically not be able to enable customers to export more than our dynamic limit of 4kW. An aggregator could also choose to use our platform to control customers' inverters. If so, they would send us an instruction in alignment with the customers' connection agreement (via a common language, or API) to only allow its customers to export 3kW, which we will action on its behalf. Thus, we will interface directly with inverters to set operating envelopes, but will not otherwise control inverters as this will

			be the role of aggregators. We consider it important to directly interface with customers' inverters when setting our operating envelope rather than sending this envelope to aggregators because we are not aware of any aggregator that has or intends to have the necessary platforms required to manage DER within dynamic network operating envelopes and we believe this is the most robust solution to maintain the integrity of our network.
		Do you expect solar exports to the HV network to lead to constraints on the HV network? How will this be managed?	We manage voltages on the HV network via HV regulators and other network devices, as well as stipulating that customers operate within certain performance metrics (e.g. variable speed drives for pumping operations). We are also developing an HV DERMs. This will help us manage the connection and operation of embedded generators
		How many noise complaints from the public have you had in relation to the ZSSs where noise related repex is proposed?	We receive around 20 noise complaints per year per network

Table 1 How our step changes meet the AER criteria

Step change	New regulatory obligation	Material increase costs of existing obligations outside of our control	Efficient opex/capex trade-off	Delivers customers benefits	Comments
5-minute settlement	✓				Currently reviewing implications of 12 month delay in new obligation
Security of critical infrastructure	✓				
Increasing insurance premiums		✓			Material increase in costs by more than 30% per year in 2018/19 and 2019/20
REFCL on-going costs	✓				Currently reviewing implications of potential change in obligations indicated by ESV
EP Amendment Act 2018 and draft regulations	✓				Currently reviewing implications of 12 month delay in new obligation
Reclassification of food belt to HBRA	✓				Currently reviewing implications of potential change in obligations indicated by CFA
Increase in ESV levy		✓			Material increase in costs by more than 33% in total during 2019/20 and 2020/21

Financial year RIN	✓				A legislated move to a financial year regulatory years requires us to double RIN audits per year

1.

EDO fuse replacements	✓			✓	Commitment in ESV approved bushfire mitigation plan reducing bushfire risk
Yarra Trams works		✓	✓		Significant works program initiated by Yarra Trams, where the operating expenditure solutions is more efficient than the capital expenditure solution
Solar enablement			✓	✓	Solar enablement represents opportunities to use an operating expenditure solution instead of augmenting the network, while delivering customer benefits
IT cloud mitigation			✓	✓	Trade-off between on-premise capital solutions and cloud operating expenditure solution
Demand management programs			✓	✓	Programs where demand management is the most efficient solution and defers capital investment

Figure 1 CitiPower, percentage of time solar is constrained (showing the impact of DVMS)

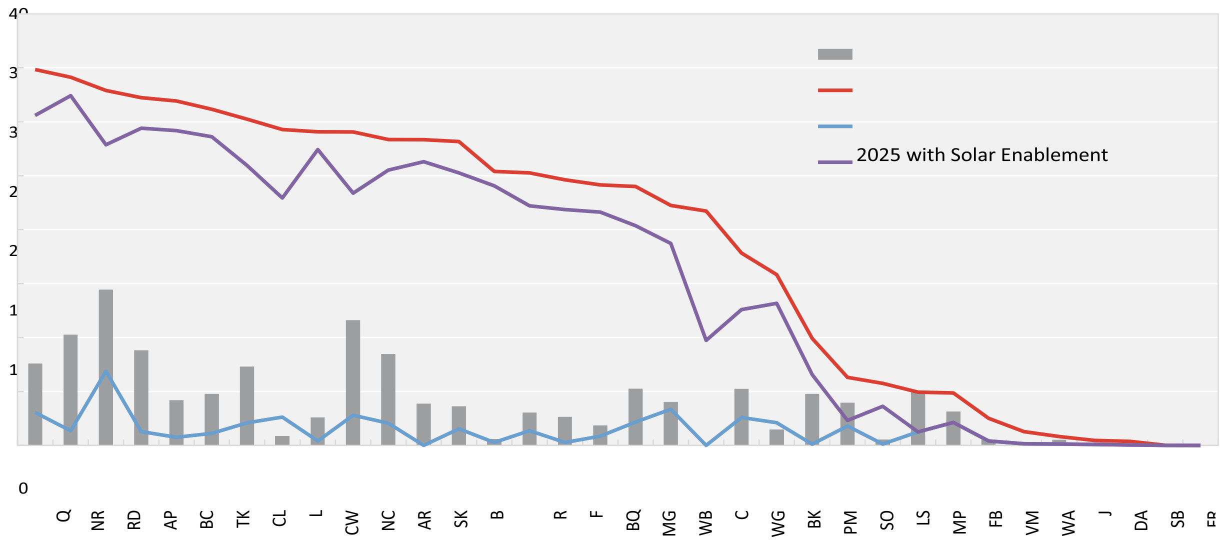


Figure 1 Powercor, percentage of time solar is constrained (showing the impact of DVMS)

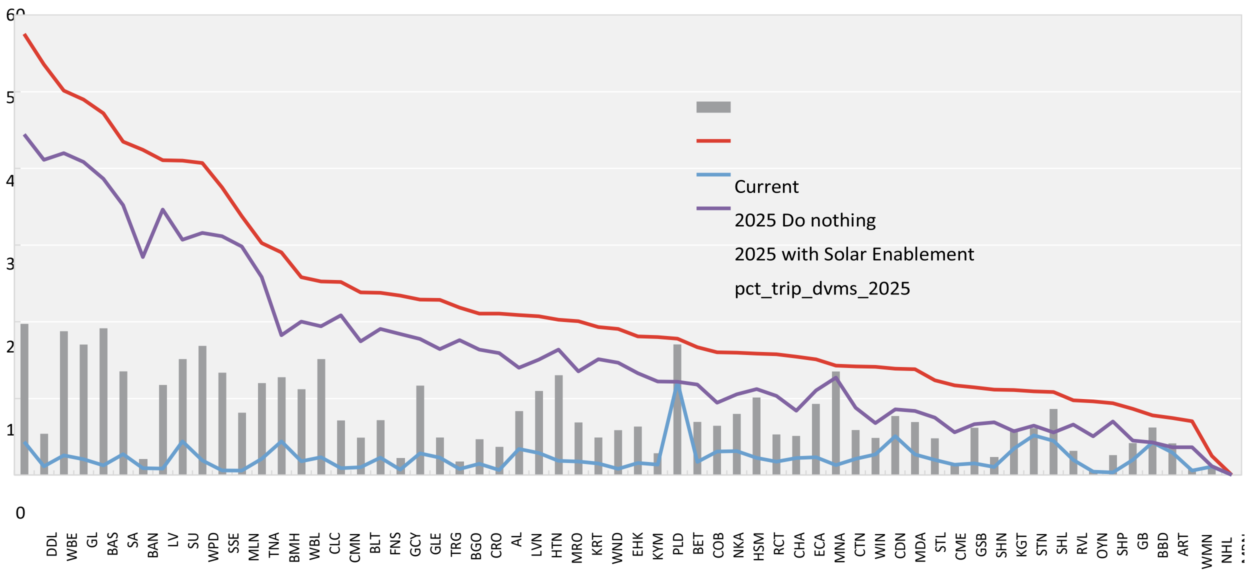


Table 2 Future network comparison

Description	CitiPower	Powercor	United Energy	AusNet
Cost information				
IT costs for digital network & solar ($m)	12	14	23	60
Solar Enablement capex ($m)	32	60	42	46
Solar Enablement opex ($m)	1.2	5.8	4.0	-
Total cost per typical residential customer p.a.	1.40	1.62	2.41	2.66
Outcomes				
Deliverables	**Digital Network** • Support innovations such as electric vehicles, DER, batteries and demand response • Proposing more granular and automated real-time capabilities, such as LV DERMS • Optimising asset management and safety benefits—energy theft detection, enhancing neutral fault detection, improving phase identification proactively manage asset failures and prevent blown fuses. **Solar Enablement** • 5KW export connection • Remove 95% of solar constraints			**Digital Network** • Support innovations such as electric vehicles, DER, batteries and demand response • Trial mini-grids **Solar Enablement** • Remove 70% of solar constraints

Jemena

Public responses provided by Jemena

Received from	Topic	Question	Reponse
Dr Judith Landsberg **Chair, Village Power**		Jemena says they want to encourage DER and in order to do this are upgrading software and sub-stations (to reduce local congestion). There appears to be little consideration of absorbing the afternoon solar peak using distributed (community) batteries to provide a more efficient response to increasing local solar energy than up-grading substations. This approach has been recommended by the WA grid as a vital component of future distributed energy resources. Furthermore it sounds like this is what the community wanted '*we consistently heard that our customers want us to green the grid*' (Future Network: Customer Engagement). The current network tariffs charged by Jemena and other networks penalise local trading by effectively doubling the network charge as energy is fed into the battery and then returned to consumers. In effect the current tariffs actively discourages community batteries and local energy trading. Is there scope to change this tariff policy or at least introduce special tariffs for	It is important that the incentives provided for the use of community batteries align to positive outcomes for all our customers, especially where its operation extends beyond the community and uses the shared network. These incentives could occur contractually or via a price signal. In terms of price signal, JEN's tariff proposal includes options that a community battery could benefit from, including demand charges and time of use charges that provide an incentive to charge before 3pm and discharge between 3-9pm. In terms of contractual or other solutions, we recognise that local trading and incentives for community batteries is a very topical discussion, and more thinking across the energy sector is required to ensure long term outcomes that benefit customers and society. For example, these issues are being considered by the Energy Security Board's two-sided markets review and the Distributed Energy Integration Program (DEIP).

		community batteries and local energy trading?	
CCP17 (questions for all DNSPs)	Prices and reliability	Consumer engagement has consistently shown that consumers want price reductions and are happy with current reliability levels. The DNSP's have shown that reliability measures are generally improving while repex spending remains a significant proportion of total capex spending. Is price the main driver for considerations of reliability related spending?	Price implications of investments are a consideration in reliability planning, however, the main driver for reliability-related spending is maintaining the current levels of service and risk. Through our engagement, customers directed us to continue with existing practices of ensuring safety risks are as low as practicable, and customer supply risks are maintained at existing levels. To ensure customers understood the price versus reliability trade-offs inherent in reliability planning, we presented them scenarios for improving, maintaining or reducing reliability, together with the associated price impacts of these scenarios. Initially, our People's Panel cohort was divided between maintaining and improving reliability. They ultimately landed on recommending we maintain current levels of reliability, but challenged us to continue to find ways to invest in ways that should see the customer experience improving, as has occurred with our use of AMI data to be faster at responding to outages.
	RAB Growth	We understand that proposed real RAB is growing for all 5 DNSP's over the next regulatory period. RAB per customer is set to decline for some DNSP's. Expecting that WACC will increase again, quite possibly during 2021-26, what impact would rising WACC have on customer bills?	Our proposal is guided by the objective of addressing affordability concerns of our customers and one way of doing that is to remain focused on a low growth in RAB per customer. Our proposal shows that it is expected to increase by an average of [x%] driven by x,y,z. A view that WACC will increase over 2021-26 is not assured. The regulatory WACC allowances are based on market conditions that would exist in the averaging period approved for a DNSP and these may result in higher or lower allowances and customer bills. We consider that movements in market conditions—which are outside of Jemena's control—are automatically reflected through the mechanisms in the AER's rate of return guideline and these will ultimately be reflected in customers' bills.

	Asset lives	Is there a standard set of asset lives (and depreciation rates) for all businesses? If not, why not?	Every business has approved standard lives for different asset categories – these categories may sometimes differ as well. The weighted asset live for a particular asset category could differ across businesses due to different asset mix within asset categories – for example, some businesses may have more rural infrastructure and some more urban, etc.
	Opex	What were the criteria that were taken into account to determine that the proposed base year is efficient?	Jemena applied AER's benchmarking techniques (including partial performance indicators, multilateral productivity and econometric methods) as well as performing a comparison to its regulatory allowances to ensure that the base year proposed is efficient and suitable for forecasting opex for the next regulatory period. (Refer to section 4.4 of our opex chapter for more details).
	Step changes	How do each of the various proposed "step changes" meet step change criteria?	The operating expenditure criteria [NER 6.5.6(c)], requires that the cost be prudent, efficient and realistic. For each step change proposed, we have only included new obligations that we cannot avoid or change in the market where Jemena has no ability to influence. In all cases, we have considered the options available, through market testing and options analysis, and have only included those costs that we believe meet the operating expenditure criteria.
	Efficiency	Multifactor productivity analysis (benchmarking) shows a declining utilisation of the network. Does this suggest that there is scope for greater efficiency of network utilisation without more spending, particularly on capital programs?	Multifactor productivity analysis measures the change in productivity (output produced per unit of labour and capital input) over time. It does not provide any useful measure of network utilisation. However, Grattan Institute undertook independent work on network investment where it benchmarked network utilisation for Australian DNSPs.[1]1 Grattan defined network use as the aggregate growth in customer numbers and growth in maximum demand. They measured network utilisation as the increase in RAB relative to growth in network use which indicates the highest network utilisation for JEN (figure 3.2 of the report). Figure 2.6 in the same report also shows

[1] Grattan Institute, *Down to the write: A sustainable electricity network for Australia*, March 2018.

			that JEN's RAB growth aligns closely to the growth in demand, implying a high network utilisation rate.
	Efficiency	Can an efficient business and a high EBSS payment for that business co-exist? What factors could lead to such an outcome?	It is possible for an already efficient business to continue reducing costs through innovation and improvements in productivity and receive EBSS payments for doing so.
	Repex	We are not clear on the status and impact of the ESV report into pole failure risk in Powercor. It appears that the CPU group are approaching this report as a mandatory requirement. Could the DNSPs please be clear what activities are undertaken as a direct result of mandatory (legislative and regulatory) bushfire mitigation requirements, and which are being undertaken for other reasons?	The Electricity Safety (Bushfire Mitigation) Regulations 2013 contain a number of specific actions which must be undertaken (e.g. installation of REFCLs, vibration dampers and armour rods) as well the requirement to develop a Bushfire Mitigation Plan which must be accepted by Energy Safe Victoria. JEN's Bushfire Mitigation Plan contains a number of programs (e.g. relating to Electric Line Clearance, Poles in Hazardous Bushfire Risk Areas (**HBRA**), installing crossarms in HBRA, overhead conductors in HBRA) ensuring we have appropriate controls in place to manage bushfire ignition risks.
	DER Integration	Analysis from CCP17 and ECA suggests that the costs to integrate DER are similar to, or perhaps even higher than, utilities elsewhere who already have higher DER penetration. We would expect that with the quality and quantity of data available through AMI which provides extensive insights into customer terminal voltage, phase balance and the like, this would provide an almost unique opportunity to efficiently reduce some of the impacts, make better risk management decisions and provide a platform for innovative voltage management. Such opportunities are not clear in the proposals, especially in leading to lower DER integration costs and innovative grid	AMI data provides us with extensive insights into the issues that high levels of DER penetration create. From this AMI data we are able to identify customers who are experiencing high/low voltages, as well as customers with high impedance connections (which we use a part of our service replacement program). However, the AMI data does not in itself make the network capable of receiving higher levels of export from DER customers. Our Future Grid Investment Proposal is based on a strategy of developing Low Voltage (**LV**) network modelling tools (using both AMI data and LV circuit/distribution substation asset data) to enable us to determine what is the most prudent and efficient approach to increasing DER hosting capacity (i.e. minimising DER export constraints) for each LV circuit and distribution substation in our network, noting that there is not one solution for them all.

		voltage management. Would the distributors care to comment on this observation?	This foundation piece of work, which is needed before we start upgrading the network to enable more DER, will require investment in our AMI systems, as well as upgrades, process changes and data capture/validation on our asset data systems GIS and SAP. Developing these LV network models will ultimately improve our customer connections, operations and network planning processes in the future, when other technologies (e.g. electric vehicles) are connected to the network.
	DER Integration	DER integration costs centre almost exclusively on managing voltage rise above legislated limits. Could the distributors comment on analysis that may have been done to implement advanced grid voltage management strategies or even voltage reduction. We also note that some utilities have offered voltage reduction as a demand response or market response opportunity, suggesting voltage reduction is possible. The change in household appliances suggests sensitivity to low voltage may be less than it has been in the past. Have distributors considered the risk and costs of reducing grid voltage and addressing low voltage issues as an alternative or delaying option to investing as widely in customer controls and LV augmentation? Have any trials to do so been considered or undertaken?	JEN has investigated various voltage management strategies and has determined that distributed voltage control is required to enable the increasing levels of DER penetration, as voltage regulation only at the zone substation level is inadequate. At our Coolaroo zone substation, which supplies several new estates in the Northern Growth Corridor, we have some customers experiencing DER inverter trips due to high voltages. In this situation, we identified that existing voltage control systems (e.g. ZSS voltage setpoints & LDC, and distribution transformer tapping) are unable to be configured to keep all customers in the supply area within the maximum and minimum voltage limits. We have also observed different LV circuits supplied from our Sunbury zone substation experiencing high volts and low volts, at the same time.
	Forecasts	How material is the disparity between the business's load forecast and AEMO forecasts, and what are the reasons for and implications of the disparity?	Each year JEN undertakes a comparison of the AEMO transmission connection point forecasts against the forecasts developed by our independent consultant. AEMO's 2019 summer POE10 connection point forecasts for Victorian predict demand growth at terminal stations BTS, SMTS,

			TSTS, KTS and WMTS, and declining demand at terminal stations BLTS and TTS. This outcome is consistent with our forecasts.
	Sensitivity analysis	In these difficult and very uncertain times no doubt the distributors are looking at their forecasts (customer growth, major infrastructure projects, demand growth, energy delivered and cost inputs) very closely. We recognise that there will be an opportunity to revise forecasts at the revised proposal stage. Can the AER and the distributors provide some insight into the key environmental variables they are watching, and what mechanisms they will be employing to revise the forecasts as necessary?	We are keenly watching out for the impacts of the current environment on many fronts. Our immediate concern is on the health and safety of our customers, contractors and staff, and we are making operational changes to address these. From an industry support point of view, we have developed a relief package to respond to the current situation, this will help to alleviate the stresses in the industry and get us all through the current challenges. With the situation changing rapidly, it is too early to make a statement around changes to our regulatory proposal because of the impacts of Covid-19.
	Demand Management	Apart from those already outlined in opex step changes, could you provide information about the business's Demand Management programs for 2021-26, and how that differs from current programs?	JEN is not proposing any step changes associated with Demand Management programs, or any specific Demand Management projects in the next regulatory period. When developing our forecast capital projects for 2021 26, JEN tested a variety of non-network options for load-driven augmentation projects and zone substation transformer and switchgear replacement projects. This analysis did not identify any demand management projects which could economically defer these investments. During the next regulatory period, at the time of these projects being initiated, we will again test non-network alternatives as part of regulatory investment test and internal processes, recognising that Demand Management and other non-network technologies continue to evolve rapidly and can be deployed outside of a price reset process. JEN will also continue to trial various demand management initiatives under the Demand Management Innovation Allowance

			Mechanism, with the aim of identifying viable demand management opportunities in the future.
	Consumer Engagement	Recognising that COVID-19 has dramatically appeared since revenue proposals were lodged, we would like to know what plans the individual businesses have for engagement in a setting where face to face engagement is likely to be constrained for a while yet? (Note that CCP17 believes that consumer and stakeholder engagement remains essential, but that the methodologies for some engagement will need to be adapted.)	Our customer engagement is a centre-piece in developing our proposal, and we have every intention of continuing this through to the final decision stage. However, the rapid and significant changes requiring social distancing will make this objective more difficult to achieve. Moving forward, we will seek to engage customer groups through the robust and reliable channel we have developed, along with the ongoing use of our customer council. We continue to maintain our relationship with members of the Peoples Panel through social media and through the jemena.yourgrid.com.au website, which is a channel that these members are accustomed to.
CCP17 (questions for AusNet, Powercor and Jemena)	REFCL benefits	Significant investment has been made in REFCL technologies, along with a long history of other bushfire mitigation investments (sparkless fuses, reclosers and the like) to address fire risk. In addition, we note in the proposals the significant investment and operating costs associated with the need to manage and operate the REFCL systems, address the reliability degradation consequential to these installations and to update plant and equipment that no longer operates as required a result of the REFCL impact on the network. We certainly note the community benefits of the REFCL investment, and do not seek to revisit any cost/benefit considerations associated with this initiative. However, two things would greatly assist consumers' assessment of the DNSP proposals, being: (a) A consolidated view of	A consolidated view of JEN's proposed REFCL program expenditure during the 2021-26 regulatory period is provided below (real June 2021 dollars, excluding overheads): Capital expenditure: $43.3M Operating expenditure step change: $1.3M Total expenditure: $44.6M Once JEN installs, commissions and has some operational experience with the REFCL installed to meet our bushfire mitigation obligations at our Coolaroo Zone Substation (by May 2023), we will assess the impact this may have on the residual bushfire mitigation risk in this area. Because the deployment of REFCLs to mitigate bushfire risk to the specification mandated in Victoria is new and has not been previously undertaken internationally, until we gain this operational experience we are unable to comment on what impact having the REFCL will have on other bushfire mitigation programs. We do, however, note that the risks associated with asset failure (e.g. poles or crossarms) in the HBRA will remain even with a REFCL installed, with *some* risk consequences being reduced.

		the aggregate cost of the REFCL program and related expenses, and (b) clarity as to how the DNSPs have changed their approach to evaluating the residual BFM risk that drives their capital program as a result of the installation of the REFCLs? Can the DNSPs point to cost benefit analyses for work proposed to address BFM risk that have changed since the installation of the REFCL systems?	
	Capex	The expenditure on REFCL technology has been significant, and the benefits in the reduction of bushfire start risk are noted. However, the large 'lumpy' expenditure on REFCL projects, in both the current and the next regulatory period, makes a 'top down' assessment of the capital investment proposals difficult. Would the DNSPs consider reframing their capex build-up and current period / proposed comparisons with the REFCL expenditure split out for clarity?	Our Proposal Attachment 05-01 presents our forecast REFCL capital expenditure separately to other programs and subcategories.
Brotherhood of St Laurence, Renew and VCOSS		A large cost item in the DER plan is the replacement of transformers, and sometimes other LV assets. Replacing transformers appears to differ from the augmentation proposed by Ausnet Services, who are proposing to replace old type ZSS and line regulator VRRs with 2-way models, as well as LV reconductor work and split circuits.	There are a number of different technical strategies and solutions which can enable more DER to be connected to the grid. Once JEN has developed our LV network modelling tools, we expect that most of our existing DER constraints will be addressed by replacing LV circuit joints, rebalancing and reconfiguring the LV network, and installing LV voltage regulation assets—with these solutions likely similar to those which the other Victorian distributors may implement. Replacing or adding new distribution transformers is one of the more costly solutions to enable DER, but remains part of our toolkit when individually assessing each identified network problem. There will likely be some instances (with particularly high levels of DER

		Why has Jemena determined that transformer replacement is required, rather than VRR replacement? Are these transformers being replaced to accommodate a larger (reverse) peak flow, or are they being replaced for specific functionality reasons (Eg 2-way flow)?	penetration) where the most prudent and efficient solution may be to replace or install a new distribution transformer. Given the relatively low levels of DER penetration for most of our network, we have not included replacement or augmentation of any HV feeder or ZSS assets in our forecast capital expenditure—however we note that each distributor may face different levels of DER penetration and different technical challenges.
		Do you expect solar exports to the HV network to lead to constraints on the HV network? How will this be managed?	Our forecasts of DER penetration suggest we are unlikely to see HV network constraints during the 2021-26 regulatory period. We may be required to modify some of our HV protection settings, and possibly replace some of our HV circuit re-closers to be by-directional. Nonetheless, our focus during the next regulatory period is on the LV network.
ECA, all DNSPs	DER integration	Both the ECA and CCP17 have carried out some broad-brush analysis regarding the cost of integrating Distributed Energy Resources. This is useful analysis, and we appreciate the ECA also exploring this area. It is difficult to draw a conclusion as to the actual cost of DER integration as the costs are often spread across a number of categories (Augex, ICT capex, opex, innovation, LV remediation). Whilst the findings draw similar conclusions, we note some differences in the output of the analysis. CCP17 is happy to share the calculations behind our analysis. Our questions are:	JEN notes that two of the capital expenditure items included in its total (the ‘Optimised Asset Investment’ projects under the augmentation and non-network IT categories) do not relate to DER integration or hosting capacity (despite forming part of our broader ‘Future Grid’ program). The objectives and drivers of our Optimised Asset Investment initiative are explained in Proposal Attachment 05-01. Once this initiative is excluded, JEN’s DER integration capex per customer using the other information contained in the CCP’s email is $69 (opex per customer unchanged). We echo the views of the CCP that there are different issues and concerns that each distributor will need to address in relation to DER. It is difficult to comment on comparisons between proposals, however, at a high level, we note that the technical challenges and external factors are likely to vary considerably between distributors, and indeed even within a single network.

		a) Could ECA share their analysis to help understand the different analytical approaches taken by ECA and CCP17? b) Could the utilities comment on the findings?	For example, not only will DER penetration levels vary, but LV network designs and configurations can result in very different problems. The solutions required to address these problems can, therefore, also vary significantly. As noted in our responses to questions above, JEN envisages deploying several different technical solutions to different DER integration issues even within our own network. Additionally, a number of the activities JEN proposes to undertake, such as the development of an LV network model, require the implementation of new IT systems. Although there may be a degree in the scalability of the expenditure required for some DER-enablement activities, the implementation of IT systems is likely to involve higher degrees of fixed costs, which may not vary according to the size of customer base—noting that JEN has a smaller customer base than most other distributors.